Joint Meeting of the WRCOG Executive Committee and Supporting Foundation

AGENDA

Monday, May 4, 2026
2:00 PM

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

Remote Meeting Location:

Sheraton Grand Hotel
1230 J Street
Sacramento, CA 95814

Members of the public are welcome to participate remotely from any location. Committee member participation is limited to locations that are listed on the published agenda.

Public Zoom Link
Meeting ID: 893 7088 6219
Passcode: 20252025
Dial in: 669 444 9171 U.S.

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) 405-6702. 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 1955 Chicago Avenue, Suite 200, Riverside, CA, 92507.

In addition to commenting at the Committee meeting, members of the public may also submit written comments before or during the meeting, prior to the close of public comment to jleonard@wrcog.us. To ensure distribution to Committee members prior to the meeting, please submit comments no later than two hours before the meeting is scheduled to begin. Public comments will also be accepted in person and via Zoom during the meeting.

Any member of the public requiring a reasonable accommodation to participate in this meeting in light of this announcement shall contact Janis Leonard 72 hours prior to the meeting at (951) 405-6702 or jleonard@wrcog.us. Later requests will be accommodated to the extent feasible.

1. CALL TO ORDER (Brenda Dennstedt, Chair)

2. PLEDGE OF ALLEGIANCE

3. ROLL CALL

4. PUBLIC COMMENTS

At this time members of the public can address the Committee regarding any items within the subject matter jurisdiction of the 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 Committee in writing and only pertinent points presented orally.

5. 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 Committee, any public comments on any of the Consent Items will be heard. There will be no separate action unless members of the Committee request specific items be removed from the Consent Calendar.

A. Action Minutes from the April 6, 2026, Meeting of the Executive Committee

Requested Action(s):

1. Approve the Action Minutes from the April 6, 2026, meeting of the Executive Committee.

B. Action Minutes from the March 27, 2026, Special Meeting of the Executive Committee

Requested Action(s):

1. Approve the Action Minutes from the March 27, 2026, special meeting of the Executive Committee.

C. WRCOG Committees and Agency Activities Update

Requested Action(s):

1. Receive and file.

D. Report out of WRCOG Representatives on Various Committees

Requested Action(s):

1. Receive and file.

E. I-REN Monthly Activities Update

Requested Action(s):

1. Receive and file.

F. Approval of a First Amendment to the Memorandum of Understanding between WRCOG and SCAG for the Regional Early Action Planning 2.0 Grant Subregional

Partnership Program

Requested Action(s):

1. Approve a First Amendment to the Memorandum of Understanding between WRCOG and SCAG for the Regional Early Action Planning (REAP) 2.0 Grant Subregional Partnership Program.
2. Authorize legal counsel to make any nonmaterial changes to the Amendment that are deemed necessary for the execution of the amendment and consistent with the project purpose.

G. Annual Used Oil Payment Program Authorization - Cycle 17

Requested Action(s):

1. Adopt Resolution Number 04-26; A Resolution of the Executive Committee of the Western Riverside Council of Governments to support Regional Application – Used Oil Payment Program – 17.

H. TUMF Program Activities Update: One TUMF Reimbursement Agreement

Requested Action(s):

1. Authorize the Executive Director to execute a TUMF Reimbursement Agreement with the County of Riverside for the Planning Phase of the Nuevo Road Widening Project in an amount not to exceed $500,000.

I. Approval of Revised Fiscal Year 2025/2026 Agency Salary Schedule

Requested Action(s):

1. Adopt Resolution Number 07-26; A Resolution of the Executive Committee of the Western Riverside Council of Governments adopting the revised Fiscal Year 2025/2026 publicly available Salary Schedule effective July 1, 2025, through June 30, 2026, as required by the California Public Employees' Retirement System, rescinding Resolution Number 20-25.

6. REPORTS / DISCUSSION

Members of the public will have an opportunity to speak on agendized items at the time the item is called for discussion.

A. Approval of a Fiscal Year 2025/2026 Supporting Foundation Budget Amendment and Adoption of Fiscal Year 2026/2027 Supporting Foundation Budget

Requested Action(s):

1. Approve the Fiscal Year 2025/2026 Supporting Foundation Budget Amendment.
2. Adopt Resolution Number 01-26; A Resolution of the Board of Directors of the Western Riverside Council of Governments Supporting Foundation adopting the Fiscal Year 2026/2027 Supporting Foundation Budget.

B. Energy Resilience Plan 2.0 Final Deliverables

Requested Action(s):

1. Receive and file.

C. Western Riverside County Clean Cities Coalition Activities Update

Requested Action(s):

1. Receive and file.

D. Regional Food Rescue Program Activities Update

Requested Action(s): 1. Receive and file.

7. REPORT FROM THE TECHNICAL ADVISORY COMMITTEE CHAIR
Craig Miller, Western Water

8. REPORT FROM COMMITTEE REPRESENTATIVES
CALCOG, Brian Tisdale
SANDAG Borders Committee, Colleen Wallace
SAWPA OWOW Steering Committee, Wes Speake
SCAG Regional Council and Policy Committee Representatives
WRCOG Ad Hoc Committees
I-REN Executive Committee

9. REPORT FROM THE EXECUTIVE COMMITTEE CHAIR
Brenda Dennstedt, Western Water

10. REPORT FROM THE INTERIM EXECUTIVE DIRECTOR
Chris Gray

Access the report here.

11. ITEMS FOR FUTURE AGENDAS
Members are invited to suggest additional items to be brought forward for discussion at future Committee meetings.

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

13. NEXT MEETING
The next Joint WRCOG Executive Committee and Supporting Foundation meeting has yet to be scheduled.

The next WRCOG Executive Committee meeting scheduled for Monday, June 1, 2026, at 2:00 p.m., in the County of Riverside Administrative Center, 4080 Lemon Street, 1st Floor, Board Chambers, Riverside.

14. ADJOURNMENT

Joint Meeting of the WRCOG Executive Committee and Supporting Foundation Board of Directors

Action Minutes

1. CALL TO ORDER

The meeting of the WRCOG Executive Committee was called to order by Chair Brenda Dennstedt at 2:18 p.m., on Monday, April 6, 2026, at the Riverside County Administrative Center, 1st Floor Board Chambers.

2. PLEDGE OF ALLEGIANCE

Caroline Hammond, WRCOG Analyst, led Committee members and guests in the Pledge of Allegiance.

3. ROLL CALL

- City of Banning - Sheri Flynn
- City of Beaumont - Mike Lara
- City of Calimesa - Eric Cundieff
- City of Canyon Lake - Mark Terry
- City of Corona - Jacque Casillas
- City of Eastvale - Christian Dinco
- City of Hemet - Connie Howard-Clark
- City of Jurupa Valley - Chris Barajas
- City of Lake Elsinore - Brian Tisdale
- City of Menifee - Bob Karwin
- City of Moreno Valley - Elena Baca - Santa Cruz
- City of Murrieta - Lori Stone
- City of Norco - Kevin Bash
- City of Perris - Michael Vargas
- City of Riverside - Chuck Conder
- City of San Jacinto - Crystal Ruiz
- City of Wildomar - Ashlee DePhillippo
- County of Riverside, District 1 - Jose Medina
- County of Riverside, District 2 - Karen Spiegel
- County of Riverside, District 3 - Chuck Washington
- Eastern Municipal Water District (EMWD) - David Slawson
- Western Water - Brenda Dennstedt

Absent:

- City of Temecula
- County of Riverside, District 5

- Riverside Co. Sup. of Schools

4. PUBLIC COMMENTS

There were no Public Comments.

5. CLOSED SESSION

1. PUBLIC EMPLOYMENT APPOINTMENT
   Title: INTERIM EXECUTIVE DIRECTOR
2. CONFERENCE WITH LABOR NEGOTIATORS
   Agency designated representatives: CHAIR and GENERAL COUNSEL
   Unrepresented employee: Deputy Executive Director / Interim Executive Director

6. OPEN SESSION

Actions:

1. Approved a bonus of $15,000.00 for the Deputy Executive Director.

RESULT:	**APPROVED AS RECOMMENDED**
MOVER:	Lake Elsinore
SECONDER:	Perris
AYES:	Banning, Beaumont, Calimesa, Canyon Lake, Corona, Eastvale, Hemet, Jurupa Valley, Lake Elsinore, Menifee, Moreno Valley, Murrieta, Norco, Perris, Riverside, Wildomar, Dist. 1, Dist. 2, Dist. 3, EMWD, Western Water
ABSENT:	San Jacinto (away from the dais)

2. Appointed Christopher Gray as the interim Executive Director.

RESULT:	**APPROVED AS RECOMMENDED**
MOVER:	Perris
SECONDER:	Moreno Valley
AYES:	Banning, Beaumont, Calimesa, Canyon Lake, Corona, Eastvale, Hemet, Jurupa Valley, Lake Elsinore, Menifee, Moreno Valley, Murrieta, Norco, Perris, Riverside, Wildomar, Dist. 1, Dist. 2, Dist. 3, EMWD, Western Water
ABSTAIN:	San Jacinto

3. Authorized an Employment Agreement with the Interim Executive Director in the amount of $289,000.00, and authorized the Chair to execute the Employment Agreement after review by legal counsel.

RESULT:	**APPROVED AS RECOMMENDED**
MOVER:	Perris
SECONDER:	Hemet
AYES:	Banning, Beaumont, Calimesa, Canyon Lake, Corona, Eastvale, Hemet, Jurupa Valley, Lake Elsinore, Menifee, Moreno Valley, Murrieta, Norco, Perris, Riverside, Wildomar, Dist. 1, Dist. 2, Dist. 3, EMWD, Western Water
ABSTAIN:	San Jacinto

7. CONSENT CALENDAR

RESULT:	**APPROVED AS RECOMMENDED**
MOVER:	Riverside
SECONDER:	Perris
AYES:	Banning, Beaumont, Calimesa, Canyon Lake, Corona, Eastvale, Hemet, Jurupa Valley, Lake Elsinore, Menifee, Moreno Valley, Murrieta, Norco, Perris, Riverside, San Jacinto, Wildomar, Dist. 1, Dist. 2, Dist. 3, EMWD, Western Water

A. Action Minutes from the March 2, 2026, Meeting of the Executive Committee

Action:

1. Approved the Action Minutes from the March 2, 2026, meeting of the Executive Committee.

B. WRCOG Committees and Agency Activities Update

Action:

1. Received and filed.

C. Report out of WRCOG Representatives on Various Committees

Action:

1. Received and filed.

D. I-REN Monthly Activities Update

Action:

1. Received and filed.

E. Vehicle Miles Traveled Mitigation Program – Credit Generator Participation Agreements with the County of Riverside Housing Authority and the City of Murrieta

Action:

1. Authorized the Executive Director to execute Credit Generator Participation Agreements with the County of Riverside Housing Authority and the City of Murrieta for the Vehicle Miles Traveled Mitigation Program.

F. Approval of a Professional Services Agreement with WSP to Provide Technical Support for the Riverside County Transportation Analysis Model Update

Action:

1. Approved the Professional Services Agreement between WRCOG and WSP to provide technical and advisory support for the update of the Riverside County Transportation Analysis Model in an amount not to exceed $449,168.

G. TUMF Program Activities Update: Two TUMF Reimbursement Agreement Amendments

Actions:

1. Authorized the Executive Director to execute a TUMF Reimbursement Agreement Amendment with the City of Wildomar for the Planning, Engineering, Right-of-Way, and Construction phases of the Palomar Road (Mission Trail to Jefferson) Project in an amount not to exceed $5,361,517.
2. Authorized the Executive Director to execute a TUMF Reimbursement Agreement Amendment with the County of Riverside for the Right-of-Way and Construction phases of the Rancho California Road-Calle Contento Roundabout Project in an amount not to exceed $9,200,000.

8. REPORTS / DISCUSSION

Items were presented out of order.

C. Approval of Updated Personnel Policies Related to WRCOG Employee Leave Benefits

RESULT:	**APPROVED AS RECOMMENDED**
MOVER:	San Jacinto
SECONDER:	Perris
AYES:	Banning, Beaumont, Calimesa, Canyon Lake, Corona, Eastvale, Hemet, Jurupa Valley, Lake Elsinore, Menifee, Moreno Valley, Murrieta, Norco, Perris, Riverside, San Jacinto, Wildomar, Dist. 1, Dist. 2, Dist. 3, EMWD, Western Water

Actions:

1. Approved the following updated personnel policies:
    A. X.1 Employee Leave Benefits: Paid Time Off Policy
    B. X.2 Employee Leave Benefits: Holidays
    C. X.3 Employee Leave Benefits: Family Medical Leave and Pregnancy Disability
    D. X.5 Employee Leave Benefits: Military Leave
    E. X.6 Employee Leave Benefits: Catastrophic Voluntary Time Bank Program

A. 2026 General Assembly Community Service Awards

RESULT:	**APPROVED AS RECOMMENDED**
MOVER:	Perris
SECONDER:	Canyon Lake
AYES:	Banning, Beaumont, Calimesa, Canyon Lake, Corona, Eastvale, Hemet, Jurupa Valley Lake Elsinore, Menifee, Moreno Valley, Murrieta, Norco, Perris, Riverside, San Jacinto, Wildomar, Dist. 1, Dist. 2, Dist. 3, EMWD, Western Water

Action:

1. Approved the following nominations for the 2026 Awards for Outstanding Community Service to be presented at the General Assembly & Leadership Address on June 18, 2026: Individuals - Mary Carnes and Monica Lyons; Groups - Eastvale Chinese American Association and Rotary Club of Murrieta.

B. I-REN Energy Fellowship 2026/2027 Program Service Year

Action:

1. Received and filed.

9. REPORT FROM THE TECHNICAL ADVISORY COMMITTEE (TAC) CHAIR

The TAC Chair was not present.

10. REPORT FROM COMMITTEE REPRESENTATIVES

Committee representatives had nothing to report.

11. REPORT FROM THE EXECUTIVE COMMITTEE CHAIR

Chair Dennstedt had nothing to report.

12. REPORT FROM THE DEPUTY EXECUTIVE DIRECTOR

Chris Gray asked the Committee to fill out the hotel reservation form if they are staying for Friday's Executive Committee meeting the day after the General Assembly event. WRCOG is currently in the process of producing a video for the General Assembly and reminded Committee members to please be on time for their scheduled filming time, as rescheduling would be costly. Finally, Mr. Gray reminded the Committee that they and their City Council members are all members of the General Assembly, and asked to confirm registration with their respective staff.

13. ITEMS FOR FUTURE AGENDAS

There were no items for future agendas.

14. GENERAL ANNOUNCEMENTS

Committee member Lori Stone wished Committee member Phil Paule a happy birthday. Ms. Stone also stated that she, Chris Gray, and elected officials from southwest Riverside County, as well as members from the Riverside Transit Agency and the Riverside County Transportation Commission will be attending a meeting in Sacramento on April 13, 2026, to testify before the Transportation Commission about Assembly Bill 2307 and discuss traffic signal synchronization to help alleviate traffic congestion on local roads.

Committee member Michael Vargas congratulated Mr. Gray on his new designation as Interim Executive Director.

Committee member Karen Spiegel also wished Phil Paule a happy birthday, and congratulated Mr. Gray on his new position.

15. NEXT MEETING

The next Executive Committee meeting is scheduled for Monday, May 4, 2026, at 2:00 p.m., in the County of Riverside Administrative Center, 4080 Lemon Street, 1st Floor, Board Chambers, Riverside.

16. ADJOURNMENT

The meeting was adjourned at 3:23 p.m.

Joint Meeting of the WRCOG Executive Committee and Supporting Foundation Board of Directors

Action Minutes

1. CALL TO ORDER

The special meeting of the WRCOG Executive Committee was called to order by Chair Brenda Dennstedt at 9:14 a.m., on Friday, March 27, 2026, at Western Municipal Water District.

2. PLEDGE OF ALLEGIANCE

Steve DeBaun, WRCOG legal counsel, led Committee members and guests in the Pledge of Allegiance.

3. ROLL CALL

- City of Banning - Sheri Flynn
- City of Beaumont - Mike Lara
- City of Calimesa - Eric Cundieff
- City of Canyon Lake - Mark Terry
- City of Corona - Jacque Casillas
- City of Eastvale - Christian Dinco
- City of Hemet - Connie Howard-Clark
- City of Lake Elsinore - Brian Tisdale
- City of Menifee - Bob Karwin
- City of Murrieta - Lori Stone
- City of Norco - Kevin Bash
- City of Riverside - Chuck Conder
- City of San Jacinto - Clarisa Sanchez*
- City of Wildomar - Ashlee DePhillippo
- County of Riverside, District 3 - Chuck Washington
- Eastern Municipal Water District (EMWD) - David Slawson
- Riverside County Superintendent of Schools - Dr. Edwin Gomez
- Western Water - Brenda Dennstedt

*Arrived after Roll Call

Absent:

- City of Jurupa Valley
- City of Moreno Valley
- City of Perris
- City of Temecula
- County of Riverside, District 1
- County of Riverside, District 2

- County of Riverside, District 5

4. PUBLIC COMMENTS

There were no Public Comments

5. CLOSED SESSION

PUBLIC EMPLOYEE DISCIPLINE / DISMISSAL / RELEASE

Action:

1. The Executive Committee voted to dismiss the Executive Director.

RESULT:	**APPROVED AS RECOMMENDED**
AYES:	Banning, Beaumont, Calimesa, Canyon Lake, Corona, Eastvale, Hemet, Lake Elsinore, Murrieta, Norco, Riverside, San Jacinto, Wildomar, Dist. 3, EMWD, Western Water
NO:	Menifee

6. REPORT FROM THE EXECUTIVE COMMITTEE CHAIR

This item was not heard.

7. ITEMS FOR FUTURE AGENDAS

This item was not heard.

8. GENERAL ANNOUNCEMENTS

This item was not heard.

9. NEXT MEETING

The next Executive Committee meeting is scheduled for Monday, April 6, 2026, at 2:00 p.m., in the County of Riverside Administrative Center, 4080 Lemon Street, 1st Floor, Board Chambers, Riverside.

10. ADJOURNMENT

The meeting was adjourned at 3:15 p.m.

Western Riverside Council of Governments Joint Meeting of the WRCOG Executive Committee and Supporting Foundation Board of Directors

Staff Report

Subject: WRCOG Committees and Agency Activities Update

Contact: Chris Gray, Deputy Executive Director, cgray@wrcog.us, (951) 405-6710

Date: May 4, 2026

Recommended Action(s):

1. Receive and file.

Summary:

Attached are summary recaps of actions and activities from recent WRCOG standing Committee meetings that occurred during the month of April 2026.

Purpose / WRCOG 2022-2027 Strategic Plan Goal:

The purpose of this item is to inform the Committee of actions and activities from WRCOG standing Committee meetings. This item aligns with WRCOG's 2022-2027 Strategic Plan Goal #4 (Communicate proactively about the role and activities of the Council of Governments).

Discussion:

A summary is provided for the following meetings that occurred in April 2026:

- April 6, 2026: Executive Committee
- April 9, 2026: Planning Directors Committee
- April 9, 2026: Public Works Committee
- April 16, 2026: Technical Advisory Committee

Prior Action(s):

None.

Financial Summary:

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

Attachment(s):

Attachment 1 - WRCOG Committees Activities Update April 2026.pdf

Western Riverside Council of Governments
Executive Committee Meeting Recap
April 6, 2026

Following is a summary of key items discussed at the last Executive Committee meeting.

Agenda Packet: https://www.wrcog.us/wp-content/uploads/2025/11/EC-0426-AP.pdf

PowerPoint Presentation: https://www.wrcog.us/wp-content/uploads/2026/04/EC-040626-PPT.pdf

2026 General Assembly Community Service Awards

- Community service Award nominees were selected by the A & F Committee and brought to the Executive Committee for approval.
- The Committee approved Mary Carnes, and Monica Lyons for the individual award, and the Eastvale Chinese American Association, and the Rotary Club of Murrieta for the group award.
- Awardees will be recognized at the 35th Annual General Assembly and Leadership Address on June 18, 2026.

I-REN Energy Fellowship 2026/2027 Program Service Year

- I-REN Energy Fellowship host agency recruitment cycle is open March 19 through May 14, 2026.
- Applications can be accessed at Partner - CivicSpark.
- Participation in the Fellowship Program comes at no cost to the participant agencies. Agencies will receive a Fellow for 11 months (full-time) to work on an agency's energy initiatives.
- Since 2023, I-REN has funded over 50 Fellows who have provided over 80,000 hours of service toward public sector agencies' energy initiatives. Many of the Fellows have helped to secure over $2M in energy incentives for their host agencies.

Approval of Updated Personnel Policies Related to WRCOG Employee Leave Benefits

- All updated employee leave-related personnel policies were reviewed and approved by the Executive Committee following prior recommendation from the Administration & Finance Committee and input from the Ad Hoc Personnel Policies Committee.
- The approved updates modernize WRCOG's policies to align with current legal requirements, streamline leave administration, and better support both operational needs and employee flexibility.
- The following policies were approved:
    1. Employee Leave Benefits: Paid Time Off (PTO) Policy
    2. Employee Leave Benefits: Holidays
    3. Employee Leave Benefits: Family Medical Leave and Pregnancy Disability Leave
    4. Employee Leave Benefits: Military Leave
    5. Employee Leave Benefits: Catastrophic Voluntary Time Bank Program

Next Meeting

The next Executive Committee meeting is scheduled for Monday, May 4, 2026, at 2:00 p.m., in the County of Riverside Administrative Center, 4080 Lemon Street, 1st Floor, Board Chambers, Riverside.

Western Riverside Council of Governments
Planning Directors Committee Meeting Recap
April 9, 2026

Following is a summary of key items discussed at the last Planning Directors Committee meeting.

Agenda Packet: https://www.wrcog.us/wp-content/uploads/2026/04/PDC-0426-AP.pdf

PowerPoint Presentation: https://www.wrcog.us/wp-content/uploads/2026/04/PDC-040926-PPT.pdf

Housing Implementation Tool (HIT) Update

- WRCOG, in partnership with Amplify Communities, has launched the Housing Implementation Tool (HIT) for member-agencies to access.
- HIT is a regional platform designed to help planners navigate and implement California's evolving housing laws by providing shared structure, reference points, and practical implementation tools. It is structured around three hubs—Planning for Housing, Housing Review & Approvals, and Resource Management—and helps agencies quickly identify applicable housing policies and supporting resources.
- Committee members and designated alternates have access to the HIT using your agency email and Microsoft login credentials here: https://wrcog.sharepoint.com/:u:/r/sites/HousingImplementation/SitePages/HomePage.aspx?csf=1&web=1&e=rsyK4y
- Access to the HIT for other users may be requested via this form: https://forms.gle/MzLAJqA1zYH4KSx96

Future Meeting Topics

- WRCOG reviewed key findings from the 2025 Annual Planning Survey, which identified staffing and funding limitations as major barriers to completing planning initiatives and complying with state requirements.
- Survey respondents requested more technical assistance, particularly templates, best practices, grant support, housing planning help, and general plan update guidance.
- The discussion during this item focused on further development of tools like the HIT, as well as how WRCOG can assist its members with the upcoming RHNA cycle. WRCOG will look into ways it can assist with the upcoming RHNA cycle and provide a staff report at a future meeting.

I-REN Energy Fellowship 2026/2027 Program Service Year

- I-REN Energy Fellowship host agency recruitment cycle is open through May 14, 2026.
- Applications can be accessed at Partner - CivicSpark.
- Participation in the Fellowship Program comes at no cost to the participant agencies. Agencies will receive a Fellow for 11 months (full-time) to work on an agency's energy initiatives.
- Since 2023, I-REN has funded over 50 Fellows who have provided over 80,000 hours of service toward public sector agencies' energy initiatives. Many of the Fellows have helped to secure over $2M in energy incentives for their host agencies.

Next Meeting

The next Planning Directors Committee meeting is scheduled for Thursday, May 14, 2026, at 9:30 a.m., at WRCOG's new office at 1955 Chicago Avenue, Riverside.

Western Riverside Council of Governments
Public Works Committee Meeting Recap
April 9, 2026

Following is a summary of key items discussed at the last Public Works Committee meeting.

Agenda Packet: https://www.wrcog.us/wp-content/uploads/2026/04/PWC-0426-AP.pdf

PowerPoint Presentation: https://www.wrcog.us/wp-content/uploads/2026/04/PWC-040926-PPT.pdf

I-REN Energy Fellowship 2026/2027 Program Service Year Activities Update

- I-REN Energy Fellowship host agency recruitment cycle is open through May 14, 2026.
- Applications can be accessed at Partner - CivicSpark.
- Participation in the Fellowship Program comes at no cost to the participant agencies. Agencies will receive a Fellow for 11 months (full-time) to work on an agency's energy initiatives.
- Since 2023, I-REN has funded over 50 Fellows who have provided over 80,000 hours of service toward public sector agencies' energy initiatives. Many of the Fellows have helped to secure over $2M in energy incentives for their host agencies.

Interstate 15 Smart Freeway Pilot Project Overview

- The I-15 Smart Freeway Pilot Project is deploying an advanced traffic management system along an eight-mile northbound corridor to reduce recurring congestion.
- The project includes enhanced vehicle detection, expanded CCTV coverage, coordinated adaptive ramp metering, part-time ramp shoulder use, and advisory variable speed limits and message signs.
- The system was undergoing baseline data collection, with full activation expected in late May 2026, followed by a two-year demonstration period to evaluate congestion, safety, travel time, and operational impacts.

Energy Resilience Plan 2.0 Final Deliverable

- The Energy Resilience Plan 2.0 has been completed and includes 8 microgrid studies, 8 community resilience center (CRC) feasibility studies, a microgrid regulatory memorandum, and an implementation plan. This project was completed with the Adaptation Planning Grant received in 2023 and builds upon the initial Energy Resilience Plan.
- The feasibility studies have been designed with future implementation in mind and aim to align potential projects with future funding for microgrids and CRCs. Each study includes a summary of the proposed microgrid system, project economics, community profile, gaps and recommendations, and next steps.
- The Implementation Plan can be used as a roadmap to conceptualize microgrid or community resilience center projects and identify the necessary steps to move towards construction.

TUMF Program Status Overview

- As of March 31, 2026, the TUMF Program has collected $36.1M for the fiscal year, with $9.6M collected in March alone. Reimbursements continue to exceed collections on active projects. A total of $57.9M has been reimbursed across 33 different projects.
- WRCOG is moving forward with adopting the Construction Cost Index (CCI) Update, which will require all member agencies to introduce new ordinances that automatically set annual fee level updates based on the CCI. The first fee schedule change is set for July 1, 2026, with subsequent updates every July

1st until a new Nexus Study is adopted. April is the last month for agencies to hold their first readings to ensure timely implementation.

- Following last month's yearly TIP meetings with each zone, all five TIPs were passed and are now advancing to Zone Executive Committee approval. Scheduled approval meetings include: Central Zone (May 19), Pass Zone (May 20), Hemet/San Jacinto Zone (May 20), Southwest Zone (May 21), and Northwest Zone (May 21).

Next Meeting

The next Public Works Committee meeting is scheduled for Thursday, April 9, 2026, at 2:00 p.m., at WRCOG's new office at 1955 Chicago Avenue, Riverside.

Western Riverside Council of Governments
Technical Advisory Committee Meeting Recap
April 16, 2026

Following is a summary of key items discussed at the last Technical Advisory Committee meeting.

Agenda Packet: https://www.wrcog.us/wp-content/uploads/2025/11/tac-0426-ap.pdf

PowerPoint Presentation: https://www.wrcog.us/wp-content/uploads/2026/04/TAC-ppt-0426.pdf

Energy Resilience Plan 2.0 Final Deliverables

- The Energy Resilience Plan 2.0 has been completed and includes 8 microgrid studies, 8 community resilience center (CRC) feasibility studies, a microgrid regulatory memorandum, and an implementation plan. This project was completed with the Adaptation Planning Grant received in 2023 and builds upon the initial Energy Resilience Plan.
- The feasibility studies have been designed with future implementation in mind and aim to align potential microgrid and CRC projects with future funding opportunities. Each study includes a summary of the proposed microgrid system and project economics, community profile, gaps and recommendations for the CRC, and next steps.
- The Implementation Plan can be used as a roadmap to conceptualize microgrid or CRC projects and identify the necessary steps to move towards construction. WRCOG and the Inland Regional Energy Network can assist agencies with exploring potential projects and providing assistance.

Next Meeting

The next Technical Advisory Committee meeting is scheduled for Thursday, May 21, 2026, at 9:30 a.m., at WRCOG's office at 1955 Chicago Avenue, Riverside.

Western Riverside Council of Governments Joint Meeting of the WRCOG Executive Committee and Supporting Foundation Board of Directors

Staff Report

Subject: Report out of WRCOG Representatives on Various Committees
Contact: Chris Gray, Interim Executive Director, cgray@wrcog.us, (951) 405-6710
Date: May 4, 2026

Recommended Action(s):

1. Receive and file.

Summary:

One key function of the Executive Committee is to appoint representatives to various external agencies, groups, and committees on behalf of WRCOG. This Staff Report provides a summary of activities related to appointments for CALCOG, the SANDAG Borders Committee, and the SAWPA OWOW Steering Committee.

Purpose / WRCOG 2022-2027 Strategic Plan Goal:

The purpose of this item to provide information regarding various external agencies, groups, and committees related to WRCOG where WRCOG has appointed one or more representative(s) to serve as its representative. This item supports WRCOG's 2022-2027 Strategic Plan Goal #4 (Communicate proactively about the role and activities of the Council of Governments).

Discussion:

CALCOG Board of Directors (Brian Tisdale)

The CALCOG Board of Directors has not met since March 9, 2026. The next CALCOG Board of Directors meeting is scheduled for June 3, 2026.

SANDAG Borders Committee (Colleen Wallace)

The SANDAG Borders Committee has not met since its last meeting of January 23, 2026. The next SANDAG Borders Committee meeting is scheduled for July 24, 2026.

SAWPA OWOW Steering Committee (Wes Speake)

The SAWPA OWOW Steering Committee has not met since its last meeting of February 26, 2026. The next SAWPA OWOW Steering Committee meeting is scheduled for May 28, 2026.

Prior Action(s):

None.

Financial Summary:

Appointed Committee members are paid $150 to attend their respective meetings. WRCOG stipends are included in the Agency's adopted Fiscal Year 2025/2026 Budget under the Administration Department in the General Fund (Fund 110).

Attachment(s):

None.

Western Riverside Council of Governments Joint Meeting of the WRCOG Executive Committee and Supporting Foundation Board of Directors

Staff Report

Subject: I-REN Monthly Activities Update

Contact: Benjamin Druyon, Program Manager, bdruyon@wrcog.us, (951) 405-6727

Date: May 4, 2026

Recommended Action(s):

1. Receive and file.

Summary:

The Inland Regional Energy Network (I-REN) is a coalition of three Councils of Government - WRCOG, the Coachella Valley Association of Governments (CVAG), and the San Bernardino Council of Governments (SBCOG) - encompassing Riverside and San Bernardino Counties, and all their respective jurisdictions within the region. These organizations have joined to establish locally administered, designed, and delivered energy efficiency programs. This report will be provided at each meeting to inform the Committee of I-REN's progress.

Purpose / WRCOG 2022-2027 Strategic Plan Goal:

The purpose of this item is to provide regular updates on I-REN activities. This effort aligns with WRCOG's 2022-2027 Strategic Plan Goal #6 (Develop and implement programs that support resilience for our region).

Discussion:

Background

In February 2021, I-REN applied for REN Program Administrator status in order to offer a portfolio of programs serving the Public, Codes & Standards, and Workforce Education & Training Sectors, with governance from WRCOG as the lead agency. In November 2021, I-REN was approved in Decision (D.) 21-11-013, Approval of Inland Regional Energy Network Energy Efficiency Business Plan, which funded I-REN to offer energy efficiency programs through program year 2027.

Present Situation

Public Sector (PS) Programs: I-REN offers two PS programs - the Technical Assistance and Strategic Energy Planning (TA) Program, and the Normalized Metered Energy Consumption (NMEC) Incentive Program. The TA Program helps agencies secure funding and financing to implement projects and provide support through construction and project close-out. The NMEC Program (publicly known as Cash for Kilowatts) provides technical support such as eligibility screening and measurement & verification, as well as incentives for meter-based energy savings. Combined with technical assistance and reinforcement of operations and management best practices, public agencies will experience maximized savings for their communities. Attachment 1 to this Staff Report highlights the Cash For Kilowatt projects currently being processed. Below are notable activities for the Public Sector this past month.

- I-REN met with staff from the City of Temecula, including its Mayor, to discuss I-REN program services and presented an updated preliminary roadmap. After the discussion, city staff were eager to engage in future opportunities across I-REN sectors.
- In late March, I-REN conducted a site visit at the County of Riverside's Benoit Detention Center in Indio. This was the County's first project and focused solely on reducing natural gas use.
- In late March, I-REN staff presented an Initial Measures List to the City of Fontana for three of its facilities (Community Center, Aquatic Center, and Library). City staff are currently reviewing the findings and will contact the I-REN team for next steps.
- The City of Blythe recently completed construction at its Police Department, Community Center, and City Hall and received installation report approval through the Southern California Regional Energy Network's (SoCalREN) Rural/Hard-to-Reach Direct Install program.
    - This marks the first collaborative effort between I-REN and SoCalREN, resulting in project success and channeled savings.
- San Bernardino Community College District's Library and North Hall Cash for Kilowatts projects both received approval for their Quarterly Savings Reports, enabling the disbursement of their first sets of Cash for Kilowatts incentive checks totaling $92,905.
- I-REN conducted its first Clean Energy & Resilience audit for the SBCTA Santa Fe Train Depot, exploring new technologies such as Solar, Battery Storage Systems, and EV Charging Infrastructure.
- I-REN tabled at United States Green Building Council's Local Government Leadership Summit hosted in the City of Riverside on March 5th, showcasing I-REN's impact to attendees.

Codes & Standards (C&S) Programs: The shared goal of I-REN's C&S Programs is to work closely with local building departments and the building industry to support, train, and enable long-term streamlining of energy code compliance. I-REN's programs will nurture the confidence, skills, and existing C&S knowledge of local building department staff, provide technical assistance to jurisdictions pursuing reach codes and local ordinances, and support building and construction industry actors to foster increased compliance. Below are updates for the C&S Programs this past month.

- On April 2, I-REN hosted its first forum of 2026: Climate Smart Compliance: Energy Code Applications for the Inland Empire. There were 54 registrants and 36 attendees, representing 10 different jurisdictions in the I-REN territory, along with strong private sector attendance.
- On April 9, I-REN partnered with the California Energy Commission (CEC) to host a webinar on the 2025 Restructured Code, supporting the CEC's efforts to solicit feedback on this proposal. This webinar garnered 41 registrants and 21 attendees.
- On April 23, I-REN hosted its third C&S event of the month, focusing on multi-family ventilation updates in the 2025 Energy Code, in partnership with Energy Code Ace.

Workforce Education & Training (WE&T) Programs: The goal of I-REN's WE&T cross-cutting Sector activities is to ensure there is a trained workforce to support and realize energy efficiency (EE) savings goals across all market sectors. I-REN is committed to identifying the most effective and accessible ways to increase the number of skilled EE workers, especially those within underserved, hard-to-reach, tribal, and disadvantaged communities. Below are updates for the WE&T Programs for this past month.

- The WE&T team published a paper through the Association of Energy Services Professional (AESP). The paper was centered around "Building Energy Workforce Pathways and Career Opportunities."
- During the months of March and April, the I-REN WE&T team attended 38 events, providing outreach and educational opportunities regarding the services I-REN provides.
- The I-REN WE&T team was able to sponsor and attend the Inland Regional Sustainability Summit on April 8th at the Riverside Convention Center. The event had over 300 people registered to attend and over 13 Energy Fellows volunteered to support the event.
- The I-REN Fellowship application opened on April 9th and will close May 22nd. Future Fellows for the upcoming 4th Cycle of the Fellowship will serve between October 2026 - September 2027.

I-REN Events / Activities Around the Region: In the coming months, I-REN activities updates will include member agency updates and spotlights on successes achieved throughout the I-REN territory.

Other Activities: Sign up for I-REN updates and learn more about all the programs, services, and resources I-REN has to offer by visiting www.iren.gov or emailing info@iren.gov.

Prior Action(s):

None.

Financial Summary:

All costs associated with I-REN Program activities are included in WRCOG's adopted Fiscal Year 2025/2026 Agency Budget under I-REN Program (Fund 180) in the Energy & Environmental Department.

Attachment(s):

Attachment 1 - Cash for Kilowatts Dashboard April 2026.pdf

iren.gov

Cash for Kilowatts April 2026 Dashboard

Incentives Update[1]

The table below shows all Cash for Kilowatts projects that have received incentive application approval. * indicates that construction start / end dates are estimated. Notable milestones to highlight for this month include:

- SBCCD Lighting SBVC Library's 1st incentive check ($43,239.34) disbursement request
- Palm Springs WB Fire Station #1 completed construction on 3/27/2026

Project	Incentive Payment	Application Approval Date	Construction Start	Construction End	Estimated Payment Date	Incentive Amount	Disbursement Request Date
Joe Baca Middle School LED Lighting Retrofit	1	7/5/2024	6/4/2024	12/20/2024	**June 2025**	$88,348.99	5/8/2025
	2				**Feb. 2026**	$132,523.81	2/19/2026
SBCCD Lighting SBVC North Hall	1	2/7/2025	2/12/2025	9/12/2025	**Feb. 2026**	$49,666.22	2/9/2026
	2				**Nov. 2026**	$74,499.34	

[1] As of 4/10/2026

The Coachella Valley Association of Governments and San Bernardino Council of Governments have partnered with the Western Riverside Council of Governments to develop I-REN to serve the cities and communities of our region.

Project	Incentive Payment	Application Approval Date	Construction Start	Construction End	Estimated Payment Date	Incentive Amount	Disbursement Request Date
SBCCD Lighting SBVC Library	1	2/24/2025	2/12/2025	9/12/2025	**April 2026**	$43,239.34	4/9/2026
	2				**Dec. 2026**	$64,859.01	
Calimesa WB Senior Center	1	4/4/2025	7/1/2025	9/27/2025	**May 2026**	$1,197.70	
	2				**Jan. 2027**	$1,796.54	
Calimesa WB City Hall	1	4/7/2025	7/1/2025	11/7/2025	**May 2026**	$1,912.53	
	2				**Dec. 2026**	$2,868.80	
Housing Authority of the County of San Bernardino WB Victorville Office	1	4/14/2025	9/2/2025	3/4/2026	**Aug. 2026**	$5,287.75	
	2				**April 2027**	$7,931.62	
Indian Wells Fire Station #55	1	3/2/2026	7/1/2026*	6/12/2027*	**Oct. 2027**	$7,494.64	
	2				**July 2028**	11,241.96	
Indian Wells Public Works Yard	1	5/21/2025	1/22/2026	8/28/2026*	**Dec. 2026**	$1,861.60	
	2				**Sept. 2027**	$2,792.40	
Housing Authority of the County of San Bernardino WB San Bernardino	1	7/16/2025	10/2/2025	11/26/2025	**May 2026**	$15,479.43	

Project	Incentive Payment	Application Approval Date	Construction Start	Construction End	Estimated Payment Date	Incentive Amount	Disbursement Request Date
Admin Office HVAC & Lighting	2				**Jan. 2027**	$23,219.15	
Rancho Mirage-I-REN-WB-Library Observatory	1	8/13/2025	5/2/2026*	12/31/2026*	**May 2027**	$9,056.48	
	2				**Feb. 2028**	$13,584.72	
Rancho Mirage-I-REN-WB-City Hall	1	8/15/2025	5/2/2026*	12/31/2026*	**April 2027**	$22,964.65	
	2				**Jan. 2028**	$34,446.98	
Town of Apple Valley WB Corporate Yard	1	9/4/2025	6/1/2026*	10/21/2026*	**Feb. 2027**	$17,270.71	
	2				**Nov. 2027**	$25,906.07	
Town of Apple Valley WB Dev. Services & Conf. Center	1	9/4/2025	6/1/2026*	10/21/2026*	**Feb. 2027**	$63,899.12	
	2				**Nov. 2027**	$95,848.68	
SBCOG Whole Building Santa Fe Train Depot	1	10/1/2025	3/30/2026	7/23/2026*	**Dec. 2026**	$37,626.48	
	2				**Sept. 2027**	$56,439.72	
Town of Apple Valley Police Department	1	10/10/2025	6/1/2026*	10/1/2026*	**Feb. 2027**	$37,904.76	
	2				**Nov. 2027**	$56,857.14	

Project	Incentive Payment	Application Approval Date	Construction Start	Construction End	Estimated Payment Date	Incentive Amount	Disbursement Request Date
Norco WB City Hall	1	10/27/2025	4/29/2026*	10/31/2026*	**Mar. 2027**	$16,693.92	
	2				**Dec. 2027**	$11,129.28	
Palm Springs WB Fire Station #1	1	11/25/2025	3/23/2026	3/27/2026	**Aug. 2026**	$3,654.00	
	2				**April 2027**	$5,481.00	
City of Murrieta Library Lighting	1	1/12/2026	6/30/2026*	8/28/2026*	**Feb. 2027**	$12,560.00	
	2				**Sept. 2027**	$18,840.00	
Beaumont Community Center Lighting	1	3/2/2026	6/1/2026*	7/1/2026*	**Nov. 2026**	$20,520.18	
	2				**July 2027**	$30,780.28	
Total Committed (includes disbursed)						**$1,127,685.00**	
Total Incentives Disbursed							**$313,778.36**

Predictability Analyses Update[2]

The table below shows Cash for Kilowatts projects that have completed a predictability analysis for the current dashboard reporting period.

Project	Pass/Fail	If failed, notes on why
Grand Terrace Richard Rollins Park WB	Electric Pass	

[2] From 3/11/2026 - 4/10/2026

Palm Desert City Hall	Electric Pass + Gas Pass	
Desert Willow Golf Resort	Electric Pass	

Incentive Rates

Base Rates

Energy Savings	Base Incentive Rate
kWh	$0.50
kW	$200.00
therms	$1.00

Incentive Kickers

Tiered kWh incentive "kickers" will also be available to encourage deep energy savings (over 15% total savings at the meter) and holistic projects. Additionally, kWh incentives will be doubled for projects that occur at a critical cooling or resiliency center.

In 2024-2026, I-REN offered its maximum incentive rate of $2.00/kWh for projects that submitted an application.

Total Savings Percentage*	Incentive Rate	Critical/Cooling/Resiliency Center Rate
Up to 15%	$0.50/kWh	$1.00/kWh
16-30%	$0.60/kWh	$1.20/kWh
31-50%	$0.70/kWh	$1.40/kWh
Over 50%	$1.00/kWh	$2.00/kWh

* Total project savings will have to pass eligibility criteria as per the NMEC Rulebook

Incentive Payout Timeline

- 3 month project completion incentive - 40% of incentive amount

  - Measures installed and post-installation inspection completed
  - 3 months of data is analyzed and incentive amount determined
- 12 month final incentive - remaining incentive payout
  - 12 months of data is analyzed and remaining incentive amount determined

Western Riverside Council of Governments Joint Meeting of the WRCOG Executive Committee and Supporting Foundation Board of Directors

Staff Report

Subject: **Approval of a First Amendment to the Memorandum of Understanding between WRCOG and SCAG for the Regional Early Action Planning 2.0 Grant Subregional Partnership Program**

Contact: **Kassie Vickers, Planner II, kvickers@wrcog.us, (951) 405-6719**

Date: **May 4, 2026**

Recommended Action(s):

1. Approve a First Amendment to the Memorandum of Understanding between WRCOG and SCAG for the Regional Early Action Planning (REAP) 2.0 Grant Subregional Partnership Program.
2. Authorize legal counsel to make any nonmaterial changes to the Amendment that are deemed necessary for the execution of the amendment and consistent with the project purpose.

Summary:

SCAG's Regional Early Action Planning (REAP) Grants 2.0 Program seeks to accelerate progress toward State housing goals and climate commitments through a strengthened partnership between the State, its regions, and local entities. Through the Subregional Partnership Program, WRCOG originally received approximately $1.6M. By approving a First Amendment to the Memorandum of Understanding, the existing budget would be reallocated. This change is inclusive of $200,000 being directed to the Riverside County Revolving Loan Fund and $26,900.42 in unallocated funds to be returned to SCAG for reprogramming.

Purpose / WRCOG 2022-2027 Strategic Plan Goal:

The purpose of this item is to reintroduce the REAP 2.0 Subregional Partnership 2.0 Program Grant. This item aligns with WRCOG's 2022-2027 Strategic Plan Goal #2 (Identify and help secure grants and other potential funding opportunities for projects and programs that benefit member agencies).

Discussion:

Background

The REAP 2.0 Program was established as part of the 2021 California Comeback Plan under AB 140 and builds on REAP 1.0, which was established in 2019, but expanded the Program focus by integrating

housing and climate goals. The Program objectives for REAP 2.0 are as follows:

1. Accelerate infill development that facilitates housing supply, choice, and affordability;
2. Affirmatively Further Fair Housing; and
3. Reduce Vehicle Miles Traveled (VMT).

The State made approximately $560M available state-wide to fund REAP Programs. Of that, SCAG received approximately $231.5M. A majority of this funding was made available to eligible entities through the following programmatic funding areas: 1) Transportation Partnership Programs; 2) Partnerships to Affirmatively Transform Homes; and 3) Subregional Partnership Program (SRP) 2.0. The SRP 2.0 Program allocated approximately $23M to subregional councils of governments (COGs) on a non-competitive basis for activities supporting cities and counties to implement projects and programs identified in their Housing Elements. The SRP approach supported housing element implementation and created a means for local efforts to align with SCAG's regional plans, implement the infill and VMT reduction goals of the Connect SoCal Plan, and support State planning goals.

WRCOG was originally awarded roughly $1.6M in funds to provide technical assistance to member agencies on qualifying REAP 2.0 projects.

Present Situation

REAP 2.0 activities must be complete by June 2026. With the Program coming to a close, WRCOG had funds that were not allocated to individual projects. To make the best use of these funds, staff is requesting $200,000 be redirected to the Riverside County Revolving Loan Fund and $26,900.42 in unallocated funds to be returned to SCAG for reprogramming. The action requested is for the WRCOG Executive Committee to authorize the Interim Executive Director to execute a First Amendment to the MOU.

Prior Action(s):

October 6, 2025: The Executive Committee approved Exhibit 1 of the MOU between WRCOG and SCAG for the REAP 2.0 grant.

December 2, 2024: The Executive Committee approved an MOU between WRCOG and SCAG for the REAP 2.0 grant.

March 6, 2023: The Executive Committee directed staff to submit a grant application to the Southern California Association of Governments for the SRP under REAP 2.0 Program in the amount of $1.6M.

Financial Summary:

Activities related to REAP 2.0 are included in WRCOG's Fiscal Year 2025/2026 budget under the General Fund (Fund 110).

Attachment(s):

Attachment 1 - First amendment to the MOU with SCAG.pdf

Docusign Envelope ID: 9240170D-96AF-4A83-93E7-2E9157845CF4

COVER PAGE
MEMORANDUM OF UNDERSTANDING
AMENDMENT NO. 1
No. M-018-25

SCAG Overall Work Program (OWP) No: 305-4927.04

MOU No: M-018-25
MOU Execution Date: February 19, 2025
Agency Contact: Christopher Tzeng (ctzeng@wrcog.us)

Sub-Recipient Name: Western Riverside Council of Governments
Sub-Recipient's UEI No: C589CLZSR4J7
MOU Amount: $1,402,933.58

Subaward Period of Performance Start Date: See Section 37
Subaward Period of Performance End Date: June 30, 2026

Type of Contract: Project Specific
Method of Payment: See Section 6 of this MOU

Project Title: Western Riverside Council of Governments REAP 2.0 Subregional Partnership 2.0 Program Grant

Project Description: Western Riverside Council of Governments will utilize REAP 2.0 funding for eligible uses and activities as provided in the Subregional Partnership Program Guidelines.

Docusign Envelope ID: 9240170D-96AF-4A83-93E7-2E9157845CF4

AMENDMENT NO. 1
TO
MEMORANDUM OF UNDERSTANDING
No. M-018-25

BETWEEN THE
SOUTHERN CALIFORNIA ASSOCIATION OF GOVERNMENTS AND
WESTERN RIVERSIDE COUNCIL OF GOVERNMENTS FOR
REAP 2.0 SUBREGIONAL PARTNERSHIP 2.0 PROGRAM GRANT

(SCAG Project/OWP No. 305-4927.04)

This Amendment No. 1 ("Amendment") to the underlying Memorandum of Understanding No. (M-018-25) ("MOU") is by and between the **SOUTHERN CALIFORNIA ASSOCIATION OF GOVERNMENTS** ("SCAG") and **WESTERN RIVERSIDE COUNCIL OF GOVERNMENTS** ("WRCOG"), subsequently herein referred to as the "Sub-Recipient," for a Subregional Partnership ("SRP") 2.0 Program Grant. SCAG and the Sub-Recipient are individually referred to herein as "Party" and may be collectively referred to herein as "Parties."

RECITALS

WHEREAS, the Parties entered into the MOU dated February 19, 2025; and

WHEREAS, Section 11 of the MOU permits the Parties to amend the MOU through written amendment; and

WHEREAS, the purpose of Amendment 1 is to amend Section 4 (Project Management): the SCAG Project Manager and Section 5 (Funding) to reflect funds directed to the Riverside County Revolving Loan Fund and funds returned to SCAG.

NOW THEREFORE, IT IS MUTUALLY AGREED THAT:

1. Section 4 (Project Management) subsection (c) is amended to read:

   b. For purposes of this MOU, Sub-Recipient designates the following individual(s) as its Project Manager:

   Kaitlin McCafferty
   Associate Regional Planner
   (213) 630-1538
   Mccafferty@scag.ca.gov

   Sub-Recipient reserves the right to change this designation upon written notice to SCAG.

Docusign Envelope ID: 9240170D-96AF-4A83-93E7-2E9157845CF4

2. **Section 5 (Funding) sub-section (a) is amended to read:**

   a. SCAG's contribution to the Projects is funded wholly with REAP 2.0 funds, in an amount not to exceed $1,402,933.58 ("Grant Funds"). The individual Projects shall be funded as follows ("Project Funds"):

      Housing Technical Assistance – $1,402,933.58

      Pursuant to WRCOG Executive Committee action, Sub-Recipient requested that $200,000 in grant funds (from the initial award of $1,629,834.00) is to be redirected to the County of Riverside, Riverside County Revolving Loan Fund and $26,900.42 in unallocated grant funds is to be returned to SCAG for reprogramming.

[Signatures on Following Page]

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SIGNATURE PAGE TO
AMENDMENT NO. 1
TO
MEMORANDUM OF UNDERSTANDING
NO. M-018-25

IN WITNESS WHEREOF, the Parties have caused this Amendment No. 1 to be executed by their duly authorized representatives as of the dates indicated below:

SOUTHERN CALIFORNIA ASSOCIATION OF GOVERNMENTS ("SCAG")

DocuSigned by:
By: Cindy Giraldo 00E46B3F0E8F43F...
Cindy Giraldo
Chief Financial Officer

4/20/2026
Date

APPROVED AS TO FORM:

DocuSigned by:
By: Richard Lam D5866DAB132A453...
Richard Lam
Senior Deputy Legal Counsel

4/20/2026
Date

WESTERN RIVERSIDE COUNCIL OF GOVERNMENTS ("Sub-Recipient")

DocuSigned by:
By: Christopher J. Gray 1C62143FCB06496...
Christopher Gray
Interim Executive Director

4/20/2026
Date

APPROVED AS TO FORM:

DocuSigned by:
By: E54DE3F1B3634C0...
Steven DeBaun
General Counsel

4/20/2026
Date

Western Riverside Council of Governments Joint Meeting of the WRCOG Executive Committee and Supporting Foundation Board of Directors

Staff Report

Subject: Annual Used Oil Payment Program Authorization - Cycle 17

Contact: Mei Wu Nguyen, Analyst I, mwu@wrcog.us, (951) 405-6734

Date: May 4, 2026

Recommended Action(s):

1. Adopt Resolution Number 04-26; A Resolution of the Executive Committee of the Western Riverside Council of Governments to support Regional Application – Used Oil Payment Program – 17.

Summary:

The Used Oil Payment Program (OPP) is provided by the California Department of Resources Recycling and Recovery (CalRecycle), which develops and promotes alternatives to the illegal disposal of used oil. Through the OPP grant, WRCOG's Used Oil Program performs outreach to used oil collection centers in our participating member cities. Additionally, the Program conducts public education and informs the public of locally available used oil and used oil filter recycling opportunities. WRCOG prepared the online annual report for the previous fiscal year's OPP activities for all participating member agencies.

Purpose / WRCOG 2022-2027 Strategic Plan Goal:

The purpose of this item is to obtain authorization from the Executive Committee to apply for annual funding on behalf of its participating member agencies and make payments for program-related matters. This effort aligns with WRCOG's 2022-2027 Strategic Plan Goal #6.3 (Continuing to support the Solid Waste & Recycling Program).

Discussion:

Background

The California Oil Recycling Enhancement Act provides funds to cities and counties for establishing and maintaining local used oil collection programs to encourage recycling and proper disposal of used oil and used oil filters. CalRecycle is responsible for administering the OPP.

WRCOG has successfully administered the regional OPP in past years on behalf of requesting member

jurisdictions. OPP funds allow WRCOG to host used oil recycling events, oil filter exchanges, education and outreach to the public, and more, on behalf of itself and the Cities of Banning, Beaumont, Calimesa, Canyon Lake, Corona, Eastvale, Hemet, Jurupa Valley, Lake Elsinore, Menifee, Murrieta, Norco, Perris, Riverside, San Jacinto, Temecula, and Wildomar.

Present Situation

Oil Payment Program - Cycle 17: During the OPP 17 cycle, WRCOG staff will host an event(s) for each participating city during Fiscal Year 2027/2028. Events can include a used oil and used oil filter exchange (and receive a new filter at no cost) at an auto parts store where residents will receive information on where to recycle household hazardous waste (HHW), antifreeze, paint, oil, batteries, and safe medicine and sharps disposals.

Events may also be other special events that the city may provide oil recycling outreach for. WRCOG can provide participants with informational flyers and an oil drain recycling container. Oil and filters may only be recycled at an auto parts store; there is no collection of used oil at special events.

WRCOG will prepare and submit the online annual report on OPP activities on behalf of all participating member agencies.

Adoption of the attached resolution authorizes WRCOG to act as a Regional Lead Participant on behalf of the specifically named participants and to make payments for program-related matters.

Prior Action(s):

None.

Financial Summary:

This funding pertains to the Used Oil Program activities for Fiscal Year 2027/2028, which will be included in the Agency's proposed Fiscal Year 2027/2028 Budget under the Environmental Department (Fund 140).

Attachment(s):

Attachment 1 - Resolution Number 04-26 to Support OPP 17.pdf

Attachment 2 - A Letter of Designation to Support Regional Application OPP 17.pdf

Attachment

Resolution Number 04-26 to support
OPP 17

RESOLUTION NUMBER 04-26

A RESOLUTION OF THE EXECUTIVE COMMITTEE OF THE WESTERN RIVERSIDE COUNCIL OF GOVERNMENTS TO SUPPORT REGIONAL APPLICATION - USED OIL PAYMENT PROGRAM - 17

WHEREAS, the Western Riverside Council of Governments ("WRCOG") is a joint powers authority consisting of the County of Riverside and 18 cities, the Eastern Municipal Water District, the Western Municipal Water District, and the Riverside County Superintendent of Schools, situated in Western Riverside County; and

WHEREAS, WRCOG operates on a fiscal year basis, beginning on July 1 of each year and continuing until June 30 of the succeeding year; and

WHEREAS, pursuant to Public Resource Code § 48690, the Department of Resources Recycling and Recovery (CalRecycle) has established the Used Oil Payment Program - 17 to make payments to qualifying jurisdictions for implementation of their used oil programs; and

WHEREAS, in furtherance of this authority, CalRecycle is required to establish procedures governing the administration of the Used Oil Payment Program - 17; and

WHEREAS, the Used Oil Payment Program - 17 allows regional participation; and

WHEREAS, CalRecycle procedures for administering the Used Oil Payment Program - 17 require, among other things, a regional applicant's governing body to declare by resolution certain authorizations related to the administration of the Used Oil Payment Program - 17.

NOW THEREFORE, BE IT RESOLVED that the WRCOG Executive Committee hereby authorizes the submittal of a regional application on behalf of itself and the Cities of Banning, Beaumont, Calimesa, Canyon Lake, Corona, Eastvale, Hemet, Jurupa Valley, Lake Elsinore, Menifee, Murrieta, Norco, Perris, Riverside, San Jacinto, Temecula and Wildomar to CalRecycle for a Local Government Used Oil Payment Program - 17.

BE IT FURTHER RESOLVED that the Executive Director, or his/her designee, is hereby authorized and empowered to execute in the name of WRCOG, all grant documents, including but not limited to, applications, agreements, annual reports including expenditure reports and amendments necessary to secure said payments to support the Used Oil Payment Program - 17; and

BE IT FURTHER RESOLVED that this authorization is effective until rescinded by the Executive Committee of the Western Riverside Council of Governments.

PASSED AND ADOPTED by the Executive Committee of the Western Riverside Council of Governments on May 4, 2026.

_____
Brenda Dennstedt, Chair
WRCOG Executive Committee

_____
Chris Gray, Secretary
WRCOG Executive Committee

Approved as to form:

_____
Steven DeBaun
WRCOG Legal Counsel

AYES: _____ NAYS: _____ ABSENT: _____ ABSTAIN: _____

Attachment

A Letter of Designation to Support Regional Application – Used Oil Payment Program - 17

May 4, 2026

California Department of Resources Recycling and Recovery (CalRecycle)
P.O Box 4025
Sacramento, CA 95812-4025

Subject: Letter of Designation – Grant and Payment Programs

Dear CalRecycle:

Pursuant to Western Riverside Council of Governments' (WRCOG) Resolution Number 04-26 authorizing an application for the Used Oil Payment Program – Cycle 17, I am the designated Signature Authority for WRCOG. I am authorized by the Resolution to execute on behalf of WRCOG, all documents, including but not limited to, applications, agreements, amendments and requests for payment, necessary to secure funds and implement the approved project. The Resolution also authorizes me to delegate this authority. Accordingly, I hereby delegate this authority to Casey Dailey, Director of Energy & Environmental Programs.

Please feel free to contact me should you have any questions at (951) 405-6710 or cgray@wrcog.us.

Sincerely,

Christopher J. Gray
Interim Executive Director

Western Riverside Council of Governments Joint Meeting of the WRCOG Executive Committee and Supporting Foundation Board of Directors

Staff Report

Subject: TUMF Program Activities Update: One TUMF Reimbursement Agreement

Contact: Brian Piche-Cifuentes, Transportation Analyst I, bpiche-cifuentes@wrcog.us, (951) 405-6705

Date: May 4, 2026

Recommended Action(s):

1. Authorize the Executive Director to execute a TUMF Reimbursement Agreement with the County of Riverside for the Planning Phase of the Nuevo Road Widening Project in an amount not to exceed $500,000.

Summary:

The County of Riverside is requesting to enter into TUMF Reimbursement Agreement with WRCOG for the Nuevo Road Widening Project. The total allocation of money across the project is $500,000.

Purpose / WRCOG 2022-2027 Strategic Plan Goal:

The purpose of this item is to request approval of one TUMF Reimbursement Agreement. This effort supports WRCOG's 2022-2027 Strategic Plan Goal #5 (Develop projects and programs that improve infrastructure and sustainable development in our subregion).

Discussion:

Background

WRCOG's TUMF Program is a subregional fee program designed to provide transportation and transit infrastructure that mitigates the impact of new growth in western Riverside County. A Reimbursement Agreement is a document between WRCOG and a member agency that allows WRCOG to provide funding for TUMF expenses incurred for the Planning, Design, Engineering, and/or Construction Phase(s) of a TUMF project. To enter into a Reimbursement Agreement, the funding for the project must first be allocated in the appropriate TUMF Zone Transportation Improvement Program (TIP). TUMF Agreements and Amendments are initiated by their respective agencies when that agency is ready for the infrastructure development.

Present Situation

TUMF Reimbursement Agreement:

1. The proposed Nuevo Road Widening Project will study the widening of the road between Dunlap Drive to Menifee Road from a two-lane roadway to a four-lane roadway. The amount of funding in the Planning Phase is set not to exceed $500,000.

Prior Action(s):

None.

Financial Summary:

TUMF activities are included in the Agency's adopted Fiscal Year 2025/2026 Budget under the Transportation Department (Program 1148, Fund 110) and the Reimbursement Agreement is consistent with the Central Zone TIP.

Attachment(s):

Attachment 1 - TUMF Reimbursement Agreement - Nuevo Road (23-CN-RCY-1199).pdf

Attachment

TUMF Reimbursement Agreement – Nuevo Road Widening

23-CN-RCY-1199

TRANSPORTATION UNIFORM MITIGATION FEE PROGRAM
AGREEMENT TO REIMBURSE TUMF FUNDS
NUEVO ROAD WIDENING
PLANNING (PLN) PHASE

THIS REIMBURSEMENT AGREEMENT ("Agreement") is entered into as of this _____day of _____, 20__, by and between the Western Riverside Council of Governments ("WRCOG"), a California joint powers authority and the County of Riverside, a political subdivision of the State of California ("AGENCY"). WRCOG and AGENCY are sometimes hereinafter referred to individually as "Party" and collectively as "Parties".

RECITALS

A. WRCOG is the Administrator of the Transportation Uniform Mitigation Fee Program of Western Riverside County ("TUMF Program").

B. WRCOG has identified and designated certain transportation improvement projects throughout Western Riverside County as projects of regional importance ("Qualifying Projects" or "Projects"). The Qualifying Projects are more specifically described in that certain WRCOG study titled "TUMF Nexus Study", as may be amended from time to time. Qualifying Projects can have Regional or Zonal significance as further described in the TUMF Nexus Study.

C. The TUMF Program is funded by TUMF fees paid by new development in Western Riverside County (collectively, "TUMF Program Funds"). TUMF Program Funds are held in trust by WRCOG for the purpose of funding the Qualifying Projects.

D. The AGENCY proposes to implement a Qualifying Project, and it is the purpose of this Agreement to identify the project and to set forth the terms and conditions by which WRCOG will release TUMF Program Funds.

AGREEMENT

NOW, THEREFORE, in consideration of the mutual covenants and subject to the conditions contained herein, the Parties hereby agree as follows:

1. Description of the Qualifying Project. This Agreement is intended to distribute TUMF Program Funds to the AGENCY for **NUEVO ROAD WIDENING**, (the "Project"), a Qualifying Project. The Work, including a timetable and a detailed scope of work, is more fully described in Exhibit "A" attached hereto and incorporated herein by reference and, pursuant to Section 20 below, is subject to modification if requested by the AGENCY and approved by WRCOG. The work shall be consistent with one or more of the defined WRCOG Call for Projects phases detailed herein as follows:

1) Planning (PLN)

2. WRCOG Funding Amount. WRCOG hereby agrees to distribute to AGENCY, on the terms and conditions set forth herein, a sum not to exceed **FIVE HUNDRED THOUSAND DOLLARS ($500,000.00),** to be used for reimbursing the AGENCY for eligible

Project expenses as described in Section 3 herein ("Funding Amount"). The Parties acknowledge and agree that the Funding Amount may be less than the actual cost of the Project. Nevertheless, the Parties acknowledge and agree that WRCOG shall not be obligated to contribute TUMF Program Funds in excess of the maximum TUMF share identified in the TUMF Nexus Study ("Maximum TUMF Share"), as may be amended from time to time.

3. Project Costs Eligible for Advance/Reimbursement. The total Project costs ("Total Project Cost") may include the following items, provided that such items are included in the scope of work attached hereto as Exhibit "A" ("Scope of Work"): (1) AGENCY and/or consultant costs associated with direct Project coordination and support; (2) funds expended in preparation of preliminary engineering studies; (3) funds expended for preparation of environmental review documentation for the Project; (4) all costs associated with right-of-way acquisition, including right-of-way engineering, appraisal, acquisition, legal costs for condemnation procedures if authorized by the AGENCY, and costs of reviewing appraisals and offers for property acquisition; (5) costs reasonably incurred if condemnation proceeds; (6) costs incurred in the preparation of plans, specifications, and estimates by AGENCY or consultants; (7) AGENCY costs associated with bidding, advertising and awarding of the Project contracts; (8) construction costs, including change orders to construction contract approved by the AGENCY; (9) construction management, field inspection and material testing costs; and (10) any AGENCY administrative cost to deliver the Project.

4. Ineligible Project Costs. The Total Project Cost shall not include the following items which shall be borne solely by the AGENCY without reimbursement: (1) any AGENCY administrative fees attributed to the reviewing and processing of the Project; and (2) expenses for items of work not included within the Scope of Work in Exhibit "A".

5. Procedures for Distribution of TUMF Program Funds to AGENCY.

(a) Initial Payment by the AGENCY. The AGENCY shall be responsible for initial payment of all the Project costs as they are incurred. Following payment of such Project costs, the AGENCY shall submit invoices to WRCOG requesting reimbursement of eligible Project costs. Each invoice shall be accompanied by detailed contractor invoices, or other demands for payment addressed to the AGENCY, and documents evidencing the AGENCY's payment of the invoices or demands for payment. Documents evidencing the AGENCY'S payment of the invoices shall be retained for four (4) years and shall be made available for review by WRCOG. The AGENCY shall submit invoices not more often than monthly and not less often than quarterly.

(b) Review and Reimbursement by WRCOG. Upon receipt of an invoice from the AGENCY, WRCOG may request additional documentation or explanation of the Project costs for which reimbursement is sought. Undisputed amounts shall be paid by WRCOG to the AGENCY within thirty (30) days. In the event that WRCOG disputes the eligibility of the AGENCY for reimbursement of all or a portion of an invoiced amount, the Parties shall meet and confer in an attempt to resolve the dispute. If the meet and confer process is unsuccessful in resolving the dispute, the AGENCY may appeal WRCOG's decision as to the eligibility of one or more invoices to WRCOG's Executive Director. The WRCOG Executive Director shall provide his/her decision in writing. If the AGENCY disagrees with the Executive Director's

decision, the AGENCY may appeal the decision of the Executive Director to the full WRCOG Executive Committee, provided the AGENCY submits its request for appeal to WRCOG within ten (10) days of the Executive Director's written decision. The decision of the WRCOG Executive Committee shall be final. Additional details concerning the procedure for the AGENCY's submittal of invoices to WRCOG and WRCOG's consideration and payment of submitted invoices are set forth in Exhibit "B", attached hereto and incorporated herein by reference.

(c) Funding Amount/Adjustment. If a post Project audit or review indicates that WRCOG has provided reimbursement to the AGENCY in an amount in excess of the Maximum TUMF Share of the Project, or has provided reimbursement of ineligible Project costs, the AGENCY shall reimburse WRCOG for the excess or ineligible payments within 30 days of notification by WRCOG.

6. Increases in Project Funding. The Funding Amount may, in WRCOG's sole discretion, be augmented with additional TUMF Program Funds if the TUMF Nexus Study is amended to increase the maximum eligible TUMF share for the Project. Any such increase in the Funding Amount must be approved in writing by WRCOG's Executive Director. In no case shall the amount of TUMF Program Funds allocated to the AGENCY exceed the then-current maximum eligible TUMF share for the Project. No such increased funding shall be expended to pay for any Project already completed. For purposes of this Agreement, the Project or any portion thereof shall be deemed complete upon its acceptance by WRCOG's Executive Director which shall be communicated to the AGENCY in writing.

7. No Funding for Temporary Improvements. Only segments or components of the construction that are intended to form part of or be integrated into the Project may be funded by TUMF Program Funds. No improvement which is temporary in nature, including but not limited to temporary roads, curbs, tapers or drainage facilities, shall be funded with TUMF Program Funds, except as needed for staged construction of the Project.

8. AGENCY's Funding Obligation to Complete the Project. In the event that the TUMF Program Funds allocated to the Project represent less than the total cost of the Project, the AGENCY shall provide such additional funds as may be required to complete the Project.

9. AGENCY's Obligation to Repay TUMF Program Funds to WRCOG; Exception For PA&ED Phase Work. Except as otherwise expressly excepted within this paragraph, in the event that: (i) the AGENCY, for any reason, determines not to proceed with or complete the Project; or (ii) the Project is not timely completed, subject to any extension of time granted by WRCOG pursuant to the terms of this Agreement; the AGENCY agrees that any TUMF Program Funds that were distributed to the AGENCY for the Project shall be repaid in full to WRCOG, and the Parties shall enter into good faith negotiations to establish a reasonable repayment schedule and repayment mechanism. If the Project involves work pursuant to a PA&ED phase, AGENCY shall not be obligated to repay TUMF Program Funds to WRCOG relating solely to PA&ED phase work performed for the Project.

10. AGENCY's Local Match Contribution. AGENCY local match funding is not required, as shown in Exhibit "A" and as called out in the AGENCY's Project Nomination Form submitted to WRCOG in response to its Call for Projects."]

11. Term/Notice of Completion. The term of this Agreement shall be from the date first herein above written until the earlier of the following: (i) the date WRCOG formally accepts the Project as complete, pursuant to Section 6; (ii) termination of this Agreement pursuant to Section 15; or (iii) the AGENCY has fully satisfied its obligations under this Agreement. All applicable indemnification provisions of this Agreement shall remain in effect following the termination of this Agreement.

12. Representatives of the Parties. WRCOG's Executive Director, or his or her designee, shall serve as WRCOG's representative and shall have the authority to act on behalf of WRCOG for all purposes under this Agreement. The AGENCY hereby designates **DENNIS ACUNA, DIRECTOR OF TRANSPORTATION**, or his or her designee, as the AGENCY's representative to WRCOG. The AGENCY's representative shall have the authority to act on behalf of the AGENCY for all purposes under this Agreement and shall coordinate all activities of the Project under the AGENCY's responsibility. The AGENCY shall work closely and cooperate fully with WRCOG's representative and any other agencies which may have jurisdiction over or an interest in the Project.

13. Expenditure of Funds by AGENCY Prior to Execution of Agreement. Nothing in this Agreement shall be construed to prevent or preclude the AGENCY from expending funds on the Project prior to the execution of the Agreement, or from being reimbursed by WRCOG for such expenditures. However, the AGENCY understands and acknowledges that any expenditure of funds on the Project prior to the execution of the Agreement is made at the AGENCY's sole risk, and that some expenditures by the AGENCY may not be eligible for reimbursement under this Agreement.

14. Review of Services. The AGENCY shall allow WRCOG's Representative to inspect or review the progress of the Project at any reasonable time in order to determine whether the terms of this Agreement are being met.

15. Termination.

(a) Notice. Either WRCOG or AGENCY may, by written notice to the other party, terminate this Agreement, in whole or in part, in response to a material breach hereof by the other Party, by giving written notice to the other party of such termination and specifying the effective date thereof. The written notice shall provide a 30 day period to cure any alleged breach. During the 30 day cure period, the Parties shall discuss, in good faith, the manner in which the breach can be cured.

(b) Effect of Termination. In the event that the AGENCY terminates this Agreement, the AGENCY shall, within 180 days, repay to WRCOG any unexpended TUMF Program Funds provided to the AGENCY under this Agreement and shall complete any portion or segment of work for the Project for which TUMF Program Funds have been provided. In the event that WRCOG terminates this Agreement, WRCOG shall, within 90 days, distribute to the

AGENCY TUMF Program Funds in an amount equal to the aggregate total of all unpaid invoices which have been received from the AGENCY regarding the Project at the time of the notice of termination; provided, however, that WRCOG shall be entitled to exercise its rights under Section 5(b), including but not limited to conducting a review of the invoices and requesting additional information. Upon such termination, the AGENCY shall, within 180 days, complete any portion or segment of work for the Project for which TUMF Program Funds have been provided. This Agreement shall terminate upon receipt by the non-terminating Party of the amounts due to it hereunder and upon completion of the segment or portion of Project work for which TUMF Program Funds have been provided.

(c) Cumulative Remedies. The rights and remedies of the Parties provided in this Section are in addition to any other rights and remedies provided by law or under this Agreement.

16. Prevailing Wages. The AGENCY and any other person or entity hired to perform services on the Project are alerted to the requirements of California Labor Code Sections 1770 et seq., which would require the payment of prevailing wages were the services or any portion thereof determined to be a public work, as defined therein. The AGENCY shall ensure compliance with these prevailing wage requirements by any person or entity hired to perform the Project. The AGENCY shall defend, indemnify, and hold harmless WRCOG, its officers, employees, consultants, and agents from any claim or liability, including without limitation attorneys, fees, arising from its failure or alleged failure to comply with California Labor Code Sections 1770 et seq.

17. Progress Reports. WRCOG may request the AGENCY to provide WRCOG with progress reports concerning the status of the Project.

18. Indemnification.

(a) AGENCY Responsibilities. In addition to the indemnification required under Section 16, the AGENCY agrees to indemnify and hold harmless WRCOG, its officers, agents, consultants, and employees from any and all claims, demands, costs or liability arising from or connected with all activities governed by this Agreement including all design and construction activities, due to negligent acts, errors or omissions or willful misconduct of the AGENCY or its subcontractors. The AGENCY will reimburse WRCOG for any expenditures, including reasonable attorneys' fees, incurred by WRCOG, in defending against claims ultimately determined to be due to negligent acts, errors or omissions or willful misconduct of the AGENCY.

(b) WRCOG Responsibilities. WRCOG agrees to indemnify and hold harmless the AGENCY, its officers, agents, consultants, and employees from any and all claims, demands, costs or liability arising from or connected with all activities governed by this Agreement including all design and construction activities, due to negligent acts, errors or omissions or willful misconduct of WRCOG or its sub-consultants. WRCOG will reimburse the AGENCY for any expenditures, including reasonable attorneys' fees, incurred by the AGENCY, in defending against claims ultimately determined to be due to negligent acts, errors or omissions or willful misconduct of WRCOG.

(c) Effect of Acceptance. The AGENCY shall be responsible for the professional quality, technical accuracy and the coordination of any services provided to complete the Project. WRCOG's review, acceptance or funding of any services performed by the AGENCY or any other person or entity under this Agreement shall not be construed to operate as a waiver of any rights WRCOG may hold under this Agreement or of any cause of action arising out of this Agreement. Further, the AGENCY shall be and remain liable to WRCOG, in accordance with applicable law, for all damages to WRCOG caused by the AGENCY's negligent performance of this Agreement or supervision of any services provided to complete the Project.

19. Insurance. The AGENCY shall require, at a minimum, all persons or entities hired to perform the Project to obtain, and require their subcontractors to obtain, insurance of the types and in the amounts described below and satisfactory to the AGENCY and WRCOG. Such insurance shall be maintained throughout the term of this Agreement, or until completion of the Project, whichever occurs last.

(a) Commercial General Liability Insurance. Occurrence version commercial general liability insurance or equivalent form with a combined single limit of not less than $1,000,000.00 per occurrence. If such insurance contains a general aggregate limit, it shall apply separately to the Project or be no less than two times the occurrence limit. Such insurance shall:

(i) Name WRCOG and AGENCY, and their respective officials, officers, employees, agents, and consultants as insured with respect to performance of the services on the Project and shall contain no special limitations on the scope of coverage or the protection afforded to these insured;

(ii) Be primary with respect to any insurance or self-insurance programs covering WRCOG and AGENCY, and/or their respective officials, officers, employees, agents, and consultants; and

(iii) Contain standard separation of insured provisions.

(b) Business Automobile Liability Insurance. Business automobile liability insurance or equivalent form with a combined single limit of not less than $1,000,000.00 per occurrence. Such insurance shall include coverage for owned, hired and non-owned automobiles.

(c) Professional Liability Insurance. Errors and omissions liability insurance with a limit of not less than $1,000,000.00 Professional liability insurance shall only be required of design or engineering professionals.

(d) Workers' Compensation Insurance. Workers' compensation insurance with statutory limits and employers' liability insurance with limits of not less than $1,000,000.00 each accident.

20. Project Amendments. Changes to the characteristics of the Project, including the deadline for Project completion, and any responsibilities of the AGENCY or WRCOG may be requested in writing by the AGENCY and are subject to the approval of WRCOG's Representative, which approval will not be unreasonably withheld, provided that extensions of time for completion of the Project shall be approved in the sole discretion of WRCOG's Representative. Nothing in this Agreement shall be construed to require or allow completion of the Project without full compliance with the California Environmental Quality Act (Public Resources Code Section 21000 *et seq.;* "CEQA") and the National Environmental Policy Act of 1969 (42 USC 4231 *et seq.*), if applicable, but the necessity of compliance with CEQA and/or NEPA shall not justify, excuse, or permit a delay in completion of the Project.

21. Conflict of Interest. For the term of this Agreement, no member, officer or employee of the AGENCY or WRCOG, during the term of his or her service with the AGENCY or WRCOG, as the case may be, shall have any direct interest in this Agreement, or obtain any present or anticipated material benefit arising therefrom.

22. Limited Scope of Duties. WRCOG's and the AGENCY's duties and obligations under this Agreement are limited to those described herein. WRCOG has no obligation with respect to the safety of any Project performed at a job site. In addition, WRCOG shall not be liable for any action of AGENCY or its contractors relating to the condemnation of property undertaken by AGENCY or construction related to the Project.

23. Books and Records. Each party shall maintain complete, accurate, and clearly identifiable records with respect to costs incurred for the Project under this Agreement. They shall make available for examination by the other party, its authorized agents, officers or employees any and all ledgers and books of account, invoices, vouchers, canceled checks, and other records or documents evidencing or related to the expenditures and disbursements charged to the other party pursuant to this Agreement. Further, each party shall furnish to the other party, its agents or employees such other evidence or information as they may require with respect to any such expense or disbursement charged by them. All such information shall be retained by the Parties for at least four (4) years following termination of this Agreement, and they shall have access to such information during the four-year period for the purposes of examination or audit.

24. Equal Opportunity Employment. The Parties represent that they are equal opportunity employers and they shall not discriminate against any employee or applicant of reemployment because of race, religion, color, national origin, ancestry, sex or age. Such non-discrimination shall include, but not be limited to, all activities related to initial employment, upgrading, demotion, transfer, recruitment or recruitment advertising, layoff or termination.

25. Governing Law. This Agreement shall be governed by and construed with the laws of the State of California.

26. Attorneys' Fees. If either party commences an action against the other party arising out of or in connection with this Agreement, the prevailing party in such litigation shall be entitled to have and recover from the losing party reasonable attorneys' fees and costs of suit.

27. Time of Essence. Time is of the essence for each and every provision of this Agreement.

28. Headings. Article and Section Headings, paragraph captions or marginal headings contained in this Agreement are for convenience only and shall have no effect in the construction or interpretation of any provision herein.

29. Public Acknowledgement. The AGENCY agrees that all public notices, news releases, information signs and other forms of communication shall indicate that the Project is being cooperatively funded by the AGENCY and WRCOG TUMF Program Funds.

30. No Joint Venture. This Agreement is for funding purposes only and nothing herein shall be construed to make WRCOG a party to the construction of the Project or to make it a partner or joint venture with the AGENCY for such purpose.

31. Compliance With the Law. The AGENCY shall comply with all applicable laws, rules and regulations governing the implementation of the Qualifying Project, including, where applicable, the rules and regulations pertaining to the participation of businesses owned or controlled by minorities and women promulgated by the Federal Highway Administration and the Federal Department of Transportation.

32. Notices. All notices hereunder and communications regarding interpretation of the terms of this Agreement or changes thereto shall be provided by the mailing thereof by registered or certified mail, return receipt requested, postage prepaid and addressed as follows:

If to AGENCY:
County of Riverside
Transportation Department
4080 Lemon Street, 8th Floor
Riverside, CA 92501
Attention: Dennis Acuna, Director of Transportation
Telephone: (951) 955-6820
Facsimile: (951) 955-3198

If to WRCOG:
Western Riverside Council of Governments
3390 University Avenue; Suite 200
Riverside, California 92501
Attention: Christopher Gray, Interim Executive Director
Telephone: (951) 405-6710
Facsimile: (951) 223-9720

Any notice so given shall be considered served on the other party three (3) days after deposit in the U.S. mail, first class postage prepaid, return receipt requested, and addressed to the party at its applicable address. Actual notice shall be deemed adequate notice on the date actual notice occurred regardless of the method of service.

33. Integration; Amendment. This Agreement contains the entire agreement between the PARTIES. Any agreement or representation respecting matters addressed herein that are not expressly set forth in this Agreement is null and void. This Agreement may be amended only by mutual written agreement of the PARTIES.

34. Severability. If any term, provision, condition or covenant of this Agreement is held invalid or unenforceable, the remainder of this Agreement shall not be affected thereby.

35. Conflicting Provisions. In the event that provisions of any attached appendices or exhibits conflict in any way with the provisions set forth in this Agreement, the language, terms and conditions contained in this Agreement shall control the actions and obligations of the Parties and the interpretation of the Parties' understanding concerning the Agreement.

36. Independent Contractors. Any person or entities retained by the AGENCY or any contractor shall be retained on an independent contractor basis and shall not be employees of WRCOG. Any personnel performing services on the Project shall at all times be under the exclusive direction and control of the AGENCY or contractor, whichever is applicable. The AGENCY or contractor shall pay all wages, salaries and other amounts due such personnel in connection with their performance of services on the Project and as required by law. The AGENCY or consultant shall be responsible for all reports and obligations respecting such personnel, including, but not limited to: social security taxes, income tax withholding, unemployment insurance and workers' compensation insurance.

37. Effective Date. This Agreement shall not be effective until executed by both Parties. The failure of one party to execute this Agreement within forty-five (45) days of the other party executing this Agreement shall render any execution of this Agreement ineffective.

38. No Third Party Beneficiaries. There are no intended third party beneficiaries of any right or obligation assumed by the Parties.

39. Counterparts. This Agreement may be signed in counterparts, each of which shall constitute an original and which collectively shall constitute one instrument.

40. Electronic Signatures. Each Party to this Agreement agrees to the use of electronic signatures, such as digital signatures that meet the requirements of the California Uniform Electronic Transactions Act ((“CUETA”) Cal. Civ. Code §§ 1633.1 to 1633.17), for executing this Agreement as well as any amendments to this Agreement . The Parties further agree that the electronic signatures of the Parties included in this Agreement are intended to authenticate this writing and to have the same force and effect as manual signatures. Electronic signature means an electronic sound, symbol, or process attached to or logically associated with an electronic record and executed or adopted by a person with the intent to sign the electronic record pursuant to the CUETA as amended from time to time. The CUETA authorizes use of an electronic signature for transactions and contracts among parties in California, including a government agency. Digital signature means an electronic identifier, created by computer, intended by the party using it to have the same force and effect as the use of a manual signature, and shall be reasonably relied upon by the parties. For purposes of this Section, a digital

signature is a type of "electronic signature" as defined in subdivision (i) of Section 1633.2 of the Civil Code.

[SIGNATURES ON FOLLOWING PAGE]

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized representatives to be effective on the day and year first above-written.

WESTERN RIVERSIDE COUNCIL OF GOVERNMENTS

By:_____
Chris Gray
Interim Executive Director

APPROVED TO FORM:

By:_____
Steven C. DeBaun
General Counsel

COUNTY OF RIVERSIDE

RECOMMENDED FOR APPROVAL:

By: _____:_____
Dennis Acuna
Director of Transportation

APPROVED AS TO FORM:
Minh C. Tran
County Counsel

By:_____
Stephanie Nelson
Deputy County Counsel

APPROVAL BY THE COUNTY BOARD OF SUPERVISORS:

By:_____

Chairman, County Board of Supervisors

ATTEST:
Kimberly Rector
Clerk of the Board

By:_____

Deputy

EXHIBIT "A"

SCOPE OF WORK

The project phase to be funded under this Agreement consists of Planning (PLN) Phase.

Nuevo Road (Project) is located in Perris, California in the unincorporated area of the County of Riverside (Agency) that connects the Nuevo community at the east end and the City of Perris and Interstate 215 (I-215) at the west end. The proposed Project will study the widening of the road between Dunlap Drive to Menifee Road from a two-lane roadway (1 lane in each direction) to a four-lane roadway (2 lanes in each direction).

The PLN phase will include data collection, field reviews, geometrics concept/alternatives needed to establish a design footprint. Once the footprint is established, environmental studies and preliminary engineering can be performed to support the environmental document. PLN phase will also include determination of utility conflicts, establishing a Right of Way Requirements Map, data sheet map, aerial and field surveys, preliminary construction cost estimates and Final Project Study Report equivalent to support the future Engineering (ENG) Phase.

EXHIBIT "A-1"

ESTIMATE OF COST

Phase	TUMF	LOCAL	TOTAL
PLANNING (PLN)	$500,000.00	$0	$500,000.00
ENGINEERING (ENG)			
RIGHT OF WAY (ROW)			
CONSTRUCTION (CON)			
TOTAL	$500,000.00	$0	$500,000.00

EXHIBIT "A-2"

PROJECT SCHEDULE

Phase	Estimated Completion Date	Estimated Cost	Comments
PLN	FY 27/28	$500,000.00	
ENG			
ROW			
CON			
TOTAL		$500,000.00	

Elements of Compensation

EXHIBIT "B"

PROCEDURES FOR SUBMITTAL, CONSIDERATION AND PAYMENT OF INVOICES

1. For professional services, WRCOG recommends that the AGENCY incorporate this Exhibit "B-1" into its contracts with any subcontractors to establish a standard method for preparation of invoices by contractors to the AGENCY and ultimately to WRCOG for reimbursement of AGENCY contractor costs.

2. Each month the AGENCY shall submit an invoice for eligible Project costs incurred during the preceding month. The original invoice shall be submitted to WRCOG's Executive Director with a copy to WRCOG's Project Coordinator. Each invoice shall be accompanied by a cover letter in a format substantially similar to that of Exhibit "B-2".

3. For jurisdictions with large construction projects (with the total construction cost exceeding $10 million) under construction at the same time, may with the approval of WRCOG submit invoices to WRCOG for payment at the same time they are received by the jurisdiction. WRCOG must receive the invoice by the 5th day of the month in order to process the invoice within 30 days. WRCOG will retain 10% of the invoice until all costs have been verified as eligible and will release the balance at regular intervals not more than quarterly and not less than semi-annually. If there is a discrepancy or ineligible costs that exceed 10% of the previous invoice WRCOG will deduct that amount from the next payment.

4. Each invoice shall include documentation from each contractor used by the AGENCY for the Project, listing labor costs, subcontractor costs, and other expenses. Each invoice shall also include a monthly progress report and spreadsheets showing the hours or amounts expended by each contractor or subcontractor for the month and for the entire Project to date. Samples of acceptable task level documentation and progress reports are attached as Exhibits "B-4" and "B-5". All documentation from the Agency's contractors should be accompanied by a cover letter in a format substantially similar to that of Exhibit "B-3".

5. If the AGENCY is seeking reimbursement for direct expenses incurred by AGENCY staff for eligible Project costs, the AGENCY shall provide the same level of information for its labor and any expenses as required of its contractors pursuant to Exhibit "B" and its attachments.

6. Charges for each task and milestone listed in Exhibit "A" shall be listed separately in the invoice.

7. Each invoice shall include a certification signed by the AGENCY Representative or his or her designee which reads as follows:

"I hereby certify that the hours and salary rates submitted for reimbursement in this invoice are the actual hours and rates worked and paid to the contractors or subcontractors listed.

Signed _____

Title _____

Date _____

Invoice No. _____

8. WRCOG will pay the AGENCY within 30 days after receipt by WRCOG of an invoice. If WRCOG disputes any portion of an invoice, payment for that portion will be withheld, without interest, pending resolution of the dispute, but the uncontested balance will be paid.

9. The final payment under this Agreement will be made only after: (I) the AGENCY has obtained a Release and Certificate of Final Payment from each contractor or subcontractor used on the Project; (ii) the AGENCY has executed a Release and Certificate of Final Payment; and (iii) the AGENCY has provided copies of each such Release to WRCOG.

EXHIBIT "B-1"
[Sample for Professional Services]

For the satisfactory performance and completion of the Services under this Agreement, Agency will pay the Contractor compensation as set forth herein. The total compensation for this service shall not exceed (_____INSERT WRITTEN DOLLAR AMOUNT___) ($___INSERT NUMERICAL DOLLAR AMOUNT___) without written approval of Agency's City Manager [or applicable position] ("Total Compensation").

1. ELEMENTS OF COMPENSATION.

Compensation for the Services will be comprised of the following elements: 1.1 Direct Labor Costs; 1.2 Fixed Fee; and 1.3 Additional Direct Costs.

1.1 DIRECT LABOR COSTS.

Direct Labor costs shall be paid in an amount equal to the product of the Direct Salary Costs and the Multiplier which are defined as follows:

1.1.1 DIRECT SALARY COSTS

Direct Salary Costs are the base salaries and wages actually paid to the Contractor's personnel directly engaged in performance of the Services under the Agreement. (The range of hourly rates paid to the Contractor's personnel appears in Section 2 below.)

1.1.2 MULTIPLIER

The Multiplier to be applied to the Direct Salary Costs to determine the Direct Labor Costs is _____, and is the sum of the following components:

1.1.2.1 Direct Salary Costs _____

1.1.2.2 Payroll Additives _____

The Decimal Ratio of Payroll Additives to Direct Salary Costs. Payroll Additives include all employee benefits, allowances for vacation, sick leave, and holidays, and company portion of employee insurance and social and retirement benefits, all federal and state payroll taxes, premiums for insurance which are measured by payroll costs, and other contributions and benefits imposed by applicable laws and regulations.

1.1.2.3 Overhead Costs _____

The Decimal Ratio of Allowable Overhead Costs to the Contractor Firm's Total Direct Salary Costs. Allowable Overhead Costs include general, administrative and overhead costs of maintaining and operating established offices, and consistent with established firm policies, and as defined in the Federal Acquisitions Regulations, Part 31.2.

Total Multiplier _____
(sum of 1.1.2.1, 1.1.2.2, and 1.1.2.3)

1.2 FIXED FEE.

1.2.1 The fixed fee is $_____.

1.2.2 A pro-rata share of the Fixed Fee shall be applied to the total Direct Labor Costs expended for services each month, and shall be included on each monthly invoice.

1.3 ADDITIONAL DIRECT COSTS.

Additional Direct Costs directly identifiable to the performance of the services of this Agreement shall be reimbursed at the rates below, or at actual invoiced cost.

Rates for identified Additional Direct Costs are as follows:

ITEM	REIMBURSEMENT RATE
	[___insert charges___]
Per Diem	$ /day
Car mileage	$ /mile
Travel	$ /trip
Computer Charges	$ /hour
Photocopies	$ /copy
Blueline	$ /sheet
LD Telephone	$ /call
Fax	$ /sheet
Photographs	$ /sheet

Travel by air and travel in excess of 100 miles from the Contractor's office nearest to Agency's office must have Agency's prior written approval to be reimbursed under this Agreement.

2. DIRECT SALARY RATES

Direct Salary Rates, which are the range of hourly rates to be used in determining Direct Salary Costs in Section 1.1.1 above, are given below and are subject to the following:

2.1 Direct Salary Rates shall be applicable to both straight time and overtime work, unless payment of a premium for overtime work is required by law, regulation or craft agreement, or is otherwise specified in this Agreement. In such event, the premium portion of Direct Salary Costs will not be subject to the Multiplier defined in Paragraph 1.1.2 above.

2.2 Direct Salary Rates shown herein are in effect for one year following the effective date of the Agreement. Thereafter, they may be adjusted annually to reflect the Contractor's adjustments to individual compensation. The Contractor shall notify Agency in writing prior to a change in the range of rates included herein, and prior to each subsequent change.

POSITION OR CLASSIFICATION	RANGE OF HOURLY RATES
[___sample___]	
Principal	$ .00 - $ .00/hour
Project Manager	$ .00 - $ .00/hour
Sr. Engineer/Planner	$ .00 - $ .00/hour
Project Engineer/Planner	$ .00 - $ .00/hour
Assoc. Engineer/Planner	$ .00 - $ .00/hour
Technician	$ .00 - $ .00/hour
Drafter/CADD Operator	$ .00 - $ .00/hour
Word Processor	$ .00 - $ .00/hour

2.3 The above rates are for the Contractor only. All rates for subcontractors to the Contractor will be in accordance with the Contractor's cost proposal.

3. INVOICING.

3.1 Each month the Contractor shall submit an invoice for Services performed during the preceding month. The original invoice shall be submitted to Agency's Executive Director with two (2) copies to Agency's Project Coordinator.

3.2 Charges shall be billed in accordance with the terms and rates included herein, unless otherwise agreed in writing by Agency's Representative.

3.3 Base Work and Extra Work shall be charged separately, and the charges for each task and Milestone listed in the Scope of Services, shall be listed separately. The charges for each individual assigned by the Contractor under this Agreement shall be listed separately on an attachment to the invoice.

3.4 A charge of $500 or more for any one item of Additional Direct Costs shall be accompanied by substantiating documentation satisfactory to Agency such as invoices, telephone logs, etc.

3.5 Each copy of each invoice shall be accompanied by a Monthly Progress Report and spreadsheets showing hours expended by task for each month and total project to date.

3.6 If applicable, each invoice shall indicate payments to DBE subcontractors or supplies by dollar amount and as a percentage of the total invoice.

3.7 Each invoice shall include a certification signed by the Contractor's Representative or an officer of the firm which reads as follows:

I hereby certify that the hours and salary rates charged in this invoice are the actual hours and rates worked and paid to the employees listed.

Signed _____

Title _____

Date _____

Invoice No. _____

4. PAYMENT

4.1 Agency shall pay the Contractor within four to six weeks after receipt by Agency of an original invoice. Should Agency contest any portion of an invoice, that portion shall be held for resolution, without interest, but the uncontested balance shall be paid.

4.2 The final payment for Services under this Agreement will be made only after the Contractor has executed a Release and Certificate of Final Payment.

EXHIBIT B-2
Sample Cover Letter to WRCOG

Date
Western Riverside Council of Governments
3390 University Avenue; Suite 450
Riverside, California 92501
Attention: Deputy Executive Director
ATTN: Accounts Payable

Re: Project Title - Invoice #__

Enclosed for your review and payment approval is the AGENCY's invoice for professional and technical services that was rendered by our contractors in connection with the 2002 Measure "A" Local Streets and Roads Funding per Agreement No. _____ effective __(Month/Day/Year)__. The required support documentation received from each contractor is included as backup to the invoice.

Invoice period covered is from __Month/Date/Year__ to __Month/Date/Year__.

Total Authorized Agreement Amount:	$0,000,000.00
Total Invoiced to Date:	$0,000,000.00
Total Previously Invoiced:	$0,000,000.00
Balance Remaining:	$0,000,000.00
Amount due this Invoice:	**$0,000,000.00**

I certify that the hours and salary rates charged in this invoice are the actual hours and rates worked and paid to the contractors listed.

By: _____
Name
Title

cc:

EXHIBIT B-3
Sample Letter from Contractor to AGENCY

Month/Date/Year

Western Riverside Council of Governments
3390 University Avenue; Suite 200
Riverside, California 92501
Attention: Deputy Executive Director
Attn: Accounts Payable Invoice #_____

For **[type of services]** rendered by **[contractor name]** in connection with **[name of project]** This is per agreement No. XX-XX-XXX effective Month/Date/Year .

Invoice period covered is from Month/Date/Year to Month/Date/Year .

Total Base Contract Amount:	$000,000.00
Authorized Extra Work (if Applicable)	$000,000.00

TOTAL AUTHORIZED CONTRACT AMOUNT:	$000,000.00
Total Invoice to Date:	$000,000.00
Total Previously Billed:	$000,000.00
Balance Remaining:	$000,000.00
Amount Due this Invoice:	$000,000.00
	==========

I certify that the hours and salary rates charged in this invoice are the actual hours and rates worked and paid to the employees listed,

By: _____
Name
Title

EXHIBIT B-4
SAMPLE TASK SUMMARY SCHEDULE
(OPTIONAL)

EXHIBIT B-5
Sample Progress Report

REPORTING PERIOD: Month/Date/Year to Month/Date/Year
PROGRESS REPORT: #1

A. Activities and Work Completed during Current Work Periods

TASK 01 – 100% PS&E SUBMITTAL
1. Responded to Segment 1 comments from Department of Transportation
2. Completed and submitted Segment 1 final PS&E

B. Current/Potential Problems Encountered & Corrective Action

Problems	Corrective Action
None	None

C. Work Planned Next Period

TASK 01 – 100% PS&E SUBMITTAL
1. Completing and to submit Traffic Signal and Electrical Design plans
2. Responding to review comments

Western Riverside Council of Governments Joint Meeting of the WRCOG Executive Committee and Supporting Foundation Board of Directors

Staff Report

Subject: Approval of Revised Fiscal Year 2025/2026 Agency Salary Schedule

Contact: Andrew Ruiz, Chief Financial Officer, aruiz@wrcog.us, (951) 405-6741

Date: May 4, 2026

Recommended Action(s):

1. Adopt Resolution Number 07-26; A Resolution of the Executive Committee of the Western Riverside Council of Governments adopting the revised Fiscal Year 2025/2026 publicly available Salary Schedule effective July 1, 2025, through June 30, 2026, as required by the California Public Employees' Retirement System, rescinding Resolution Number 20-25.

Summary:

WRCOG is required by CalPERS to have its governing body approve its annual Agency Salary Schedule. For Fiscal Year 2025/2026, WRCOG's Salary Schedule has been revised to reflect the Interim Executive Director's salary.

Purpose / WRCOG 2022-2027 Strategic Plan Goal:

The purpose of this item is to request adoption of the revised Fiscal Year 2025/2026 Agency Salary Schedule. This item aligns with WRCOG's 2022-2027 Strategic Plan Goal #3 (Ensure fiscal solvency and stability of the Western Riverside Council of Governments).

Discussion:

Background

Per California Code of Regulations Section 570.5, a public agency must have its salary schedules approved by its Board, or highest governing body. Attachment 1 to this Staff Report includes the Agency's revised Salary Schedule, effective July 1, 2025.

Present Situation

A revised salary schedule is being brought forward in order to reflect the Interim Executive Director's salary. No other changes are being made to the salary schedule.

Prior Action(s):

None.

Financial Summary:

The revised salary schedule, incorporating the recently approved Interim Executive Director salary, is fully supported within WRCOG's adopted Fiscal Year 2025/2026 budget; therefore, no budget amendments are required.

Attachment(s):

Attachment 1 - Resolution Number 07-26 Adopting Publicly Available Pay Schedules for FY 2025/2026.pdf

Attachment

Resolution Number 07-26 adopting a revised FY 2025/2026 salary schedule

RESOLUTION NUMBER 07-26

A RESOLUTION OF THE EXECUTIVE COMMITTEE OF THE WESTERN RIVERSIDE COUNCIL OF GOVERNMENTS ADOPTING A REVISED FISCAL YEAR 2025/2026 PUBLICLY AVAILABLE SALARY SCHEDULE EFFECTIVE JULY 1, 2025, THROUGH JUNE 30, 2026, AS REQUIRED BY THE CALIFORNIA PUBLIC EMPLOYEES' RETIREMENT SYSTEM, RESCINDING RESOLUTION NUMBER 20-25

WHEREAS, the Western Riverside Council of Governments (WRCOG) is a participant in the California Public Employees' Retirement System (CalPERS); and

WHEREAS, as defined in the California Code of Regulations, Title 2, Section 570.5, pay schedules must indicate the time base and must be approved and adopted by the Agency's governing body in accordance with requirements of applicable public meeting laws; and

WHEREAS, per California Code of Regulations, Title 2, Section 570.5, a public agency must have its salary schedules approved by its Board, or highest governing body. Therefore, WRCOG must adopt a salary schedule for Fiscal Year 2025/2026; and

WHEREAS, to ensure compliance with the California Code of Regulations, Title 2, Section 570.5, CalPERS has required that the WRCOG Executive Committee adopt a revised Fiscal Year 2025/2026 publicly available salary schedule for WRCOG employees, attached hereto as Exhibit "A," effective July 1, 2025, through June 30, 2026.

NOW, THEREFORE, BE IT RESOLVED by the Executive Committee, acting on behalf of the General Assembly, as follows:

Section 1. The above recitals are incorporated herein by this reference.

Section 2. The Executive Committee of the Western Riverside Council of Governments hereby adopts the Fiscal Year 2025/2026 publicly available salary schedule for WRCOG employees, attached hereto as Exhibit "A" and incorporated herein by this reference, effective July 1, 2025, through June 30, 2026.

PASSED AND ADOPTED by the Executive Committee of the Western Riverside Council of Governments on May 4, 2026.

_____	_____
Brenda Dennstedt, Chair	Christopher Gray, Secretary
WRCOG Executive Committee	WRCOG Executive Committee

Approved as to form:

_____
Steven DeBaun
WRCOG Legal Counsel

AYES: _____ NAYS: _____ ABSENT: _____ ABSTAIN: _____

EXHIBIT “A”

REVISED SALARY SCHEDULE FOR FISCAL YEAR 2025/2026

[ATTACHED]

Western Riverside Council of Governments
Staff Salary Schedule
As of July 1, 2025

CLASSIFICATION	ANNUAL SALARY RANGE Bottom	Top
Deputy Executive Director*	210,309	289,931
Director*	156,936	216,320
Program Manager*	117,125	161,450
Analyst III	91,749	126,485
Analyst II	83,221	114,733
Analyst I	75,483	104,062
Open Space Habitat Technician II	59,155	81,578
Open Space Habitat Technician I	53,643	73,986
Program Specialist III	65,208	89,835
Program Specialist II	59,155	81,578
Program Specialist I	53,643	73,986
Intern**	16,800	41,600

Full-time positions have 14 steps within their range, increasing at 2.5% each step.

CLASSIFICATION	ANNUAL SALARY RANGE
Interim Executive Director*	$288,995

*Salaried Position
**Hourly Position

Western Riverside Council of Governments
Staff Salary Schedule
As of July 1, 2025

CLASSIFICATION	ANNUAL SALARY RANGE Bottom	Top
Deputy Executive Director*	210,309	289,931
Director*	156,936	216,320
Program Manager*	117,125	161,450
Analyst III	91,749	126,485
Analyst II	83,221	114,733
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Open Space Habitat Technician II	59,155	81,578
Open Space Habitat Technician I	53,643	73,986
Program Specialist III	65,208	89,835
Program Specialist II	59,155	81,578
Program Specialist I	53,643	73,986
Intern**	16,800	41,600

Full-time positions have 14 steps within their range, increasing at 2.5% each step.

CLASSIFICATION	ANNUAL SALARY RANGE
Interim Executive Director*	$288,995

*Salaried Position
**Hourly Position
Employees are paid bi-weekly.

WRCOG Stipends for Elected Officials:

Stipends of $150 per meeting are provided to Executive Committee Members for attendance at WRCOG's Executive Committee Meetings (11 scheduled meetings per year) and Administration & Finance Committee meetings (10 scheduled meetings per year).

WRCOG also provides stipends to elected officials appointed by the Executive Committee to represent WRCOG in instances where the meeting attended is not reimbursed by another agency. These include:

1) California Association of Council of Governments (CALCOG): 6-7 meetings per year (1 WRCOG appointee).
2) San Diego Association of Governments (SANDAG) Borders Policy Committee: 4 meetings per year (1 WRCOG appointee).
3) Santa Ana Watershed Project Authority (SAWPA) One Water One Watershed (OWOW) Steering Committee: 6 meetings per year (1 WRCOG appointee).
4) Riverside County Waste Management Local Task Force: 1 meeting annually (2 WRCOG appointees).
5) Other meetings Executive Committee Members attend as appointed representatives of WRCOG.

Western Riverside Council of Governments Joint Meeting of the WRCOG Executive Committee and Supporting Foundation Board of Directors

Staff Report

Subject: **Approval of a Fiscal Year 2025/2026 Supporting Foundation Budget Amendment and Adoption of Fiscal Year 2026/2027 Supporting Foundation Budget**

Contact: **Louis Fernandez, Accounting Manager, lfernandez@wrcog.us, (951) 405-6743**
Bonnie Woodrome, Communications & External Affairs Manager, bwoodrome@wrcog.us, (951) 533-3726

Date: **May 4, 2026**

Recommended Action(s):

1. Approve the Fiscal Year 2025/2026 Supporting Foundation Budget Amendment.
2. Adopt Resolution Number 01-26; A Resolution of the Board of Directors of the Western Riverside Council of Governments Supporting Foundation adopting the Fiscal Year 2026/2027 Supporting Foundation Budget.

Summary:

The Fiscal Year 2025/2026 Supporting Foundation Budget Amendment is being presented for consideration and approval now that several key costs have been determined; the Fiscal Year 2026/2027 Supporting Foundation Budget is also being presented for adoption. The Budget Amendment for Fiscal Year 2025/2026 revises the budget to $440,015 in revenues against $426,960 in expenditures, which represents a total increase of $74,515 in revenues and $63,510 in expenditures. The Fiscal Year 2026/2027 Budget anticipates $448,050 in revenues against $434,995 in expenditures. Changes are attributed to the increases in in-kind sponsorships and the addition of the Women's Day Forum budgeted revenue and expense amounts to the Supporting Foundation budget.

Purpose / WRCOG 2022-2027 Strategic Plan Goal:

The purpose of this item is to present the Supporting Foundation Fiscal Year 2025/2026 Budget Amendment for approval and the Fiscal Year 2026/2027 Supporting Foundation Budget for adoption by the Board of Directors. This item aligns with Strategic Plan Goal #3 (Ensure fiscal solvency and stability of the Western Riverside Council of Governments).

Discussion:

Background

In 2006, the Supporting Foundation was formed to assist WRCOG with the implementation of its programs, primarily to provide a non-profit entity that could receive grant funds and donations which WRCOG could otherwise not accept. To that end, WRCOG established the Supporting Foundation as a 501(c)3 non-profit entity.

As defined in the Foundation's formation documents, the Executive Committee serves as the Board of Directors for the Supporting Foundation. The Chair and Vice-Chair of the Executive Committee serve as the President and Vice-President of the Supporting Foundation, respectively. The Executive Director serves as the Secretary of the Supporting Foundation and the Chief Financial Officer (CFO) serves as the Treasurer.

Since 2006, the Supporting Foundation had periodically received grant funds and donations which were then transferred to WRCOG to support various programmatic uses. The Supporting Foundation had also periodically accepted donations for the General Assembly & Leadership Address in those instances in which a sponsor desired to take advantage of the Supporting Foundation tax-exempt status. However, the Supporting Foundation had not been directly involved in the General Assembly & Leadership Address events except in those rare instances in which a sponsor wished to use the Supporting Foundation to receive their donations.

On May 2, 2022, the Supporting Foundation Board of Directors adopted a resolution to memorialize the scope of activities and expenditure authority related to the General Assembly event. This resolution adopted policies that allowed the Supporting Foundation to support the General Assembly & Leadership Address and authorized the Secretary and Treasurer to 1) accept all funds, 2) transfer funds in any amount to WRCOG in order to support or reimburse any WRCOG activities, and 3) authorize expenditures in a manner consistent with the WRCOG spending policy, including the ability to authorize expenditures in amounts not to exceed $100k. Additionally, the resolution authorized the officers of the Foundation, namely the Secretary and Treasurer, to accept donations made to the Foundation for any purpose, including those earmarked for support of the annual General Assembly & Leadership Address.

The General Assembly Ad Hoc Committee Addresses Cost Drivers

The General Assembly Ad Hoc Committee was formed to address rising event costs; in its initial meetings, the Committee focused on cost-saving measures, with a second phase following the 2026 event to evaluate revenue opportunities.

The Committee reviewed key cost drivers associated with the event and identified several opportunities to improve efficiency while maintaining the overall quality and experience of the program. Staff has begun implementing the below adjustments to balance fiscal responsibility with delivering a high-quality event. *(Note: Costs are based on 2025 estimates and may increase in 2026.)*

Key actions include reducing the number of complimentary tickets at the discretion of the Executive Director to prioritize essential attendees; increasing individual ticket prices from $150 to $200 to better align with the approximate $450 per-person cost; and modifying the meal program by removing the beef option in favor of chicken and vegetarian selections.

Additional adjustments include scaling back hors d’oeuvres to a VIP-only offering with more cost-effective options, evaluating beverage service to reduce per-drink costs and improve service efficiency,

and replacing a live band with a DJ to lower entertainment expenses. Staff will also explore operational improvements such as adding bar service stations, if feasible within budget, to address service demand.

Finally, the Committee recommended a more strategic allocation of shared costs between the General Assembly and WRCOG's administrative budget for dual-purpose services such as ticketing, videography, and event materials, which could reduce the General Assembly budget. Opportunities to offset smaller ancillary costs, such as the Friday morning breakfast, through sponsorship or alternative funding sources will also be pursued.

WRCOG Women's Day Forum

WRCOG hosted its annual Women's Day Forum on March 10, 2026, at the Moreno Valley Conference Center. Honoring International Women's Day and bringing together more than 200 attendees from across the Inland Empire for a half-day of connection, reflection, and inspiration. Attendees - including students, professionals, and regional leaders - participated in a vendor showcase, roundtable discussions, and networking opportunities designed to foster mentorship and shared learning.

This year, Women's Day Forum donations were collected by the Foundation. This is a departure from past practice and is intended to offer a non-profit option for sponsors and facilitate greater transparency to demonstrate the source of funds for the event.

Fiscal Year 2025/2026 Budget Amendment

The adopted Fiscal Year (FY) 2025/2026 Budget was primarily based on the known costs at the time for the 2025 General Assembly event. While this gave a reasonable basis for the overall budget amount, the individual costs for the General Assembly event are not known until certain key events occur. Specifically, the event venue selection, speaker selection, and anticipated number of guests are the biggest variables in budgeting for the event. As the event venue, speaker, and anticipated number of guests have now been determined, staff are presenting an amendment to the FY 2025/2026 budget that more accurately depicts the costs for the event. Additionally, included in the Budget Amendment are the revenues and expenses for WRCOG's Women's Day Forum event.

The revised Budget for FY 2025/2026 anticipates $440,015 in revenues (sponsorships, ticket sales, and in-kind sponsorships) against $426,960 in expenditures, which represents a total increase of $74,515 in revenues and $63,510 in expenditures. Revenue and expense increases are a net result from increases in in-kind sponsorship amounts ($61,000) and the addition of the Women's Day Forum budgeted revenue and expense amounts ($27,515) to the Supporting Foundation budget. Additionally, decreases to catering, musician, and AV budgeted line items in the total amount of $10,500.

FY 2026/2027 Budget

Historically, the upcoming budget is based on the updated budget for the current year. Basing the upcoming year's budget with the current year's budget gives a reasonable basis for the overall budget amount. As previously noted, the individual costs for the General Assembly event are not known until certain key events occur. Of the three variables (speaker, venue, number of guests), the biggest variable has historically been the speaker fee. For planning purposes, the speaker fee is being budgeted at $100,000, which represents an approximate average from prior years.

Projected expenses for FY 2026/2027 are budgeted at $434,995 and projected revenues are budgeted at $448,050. Changes from the prior year budget amounts are a result of increases in in-kind sponsorships and the addition of the Women's Day Forum budgeted revenue and expense amounts to the Supporting Foundation budget.

Once the Committee makes a speaker selection for the 2027 General Assembly event and other key events occur, a budget amendment will be brought forward to amend the FY 2026/2027 budget.

Prior Action(s):

None.

Financial Summary:

The Budget Amendment for Fiscal Year 2025/2026 revises the budget to $440,015 in revenues against $426,960 in expenditures.

The Fiscal Year 2026/2027 budget anticipates $448,050 in revenues against $434,995 in expenditures; however, a budget amendment will be brought forward once certain expenditures have been finalized.

As of June 30, 2025, the Supporting Foundation had a fund balance of $127k. The total fund balance serves as a useful measure of the Foundation's net resources available for spending at the end of the fiscal year. The anticipated fund balance for FY 2025/2026 is approximately $140k.

Attachment(s):

Attachment 1 - FY 2025/2026 Foundation Budget Amendment

Attachment 2 - Resolution 01-26 adopting FY 20262027 Foundation Budget.pdf

Attachment

Fiscal Year 2025/2026
Supporting Foundation
Budget Amendment



Western Riverside Council of Governments
Supporting Foundation
Fiscal Year 2025/2026 Budget Amendment

		Actual	FY 26 Budget	Difference	Amendment	Amended FY 26 Budget Amount
Revenue:						
	Sponsorships & Individual Tickets	$ 258,020	$ 305,000	$ 46,980	$ 13,515	$ 318,515
	Tribal Sponsorship - in-kind	55,000	50,000	(5,000)	5,000	55,000
	Other Sponsorship - in-kind	66,500	10,500	(56,000)	56,000	66,500
	Total Revenue	**$ 379,520**	**$ 365,500**	**$ (14,020)**	**$ 74,515**	**$ 440,015**
Expenditures:						
	Event Support	$ 103,581	$ 141,700	$ 38,119	7,500	$ 149,200
	Venue, Catering, & AV	107,650	157,000	49,350	25,495	182,495
	Graphic Design Services	32,488	27,000	(5,488)	23,765	50,765
	Hotel Expenses	-	17,000	17,000	1,000	18,000
	Program/Promotional Expenses	5,956	20,750	14,794	5,750	26,500
	Total Expenditures	**$ 249,676**	**$ 363,450**	**$ 113,774**	**$ 63,510**	**$ 426,960**

Western Riverside Council of Governments
Supporting Foundation
Fiscal Year 2025/2026 Budget Amendment

General Assembly

		Actual	FY 26 Budget	Difference	Amendment	Amended FY 26 Budget Amount
Revenue:						
	Sponsorships & Individual Tickets	$ 244,505	$ 305,000	$ 60,495	$ -	$ 305,000
	Tribal Sponsorship - in-kind	55,000	50,000	(5,000)	5,000	55,000
	Other Sponsorship - in-kind	52,500	10,500	(42,000)	42,000	52,500
	Total Revenue	**$ 352,005**	**$ 365,500**	**$ 13,495**	**$ 47,000**	**$ 412,500**
Expenditures:						
	Event Support	$ 103,581	$ 141,700	$ 38,119	7,500	$ 149,200
	Venue, Catering, & AV	89,500	157,000	67,500	7,345	164,345
	Graphic Design Services	23,123	27,000	3,877	14,400	41,400
	Pechanga Hotel Expenses	-	17,000	17,000	1,000	18,000
	Program/Promotional Expenses	5,956	20,750	14,794	5,750	26,500
	Total Expenditures	**$ 222,161**	**$ 363,450**	**$ 141,289**	**$ 35,995**	**$ 399,445**

Western Riverside Council of Governments
Supporting Foundation
Fiscal Year 2025/2026 Budget Amendment

Women's Forum

		Actual	FY 26 Budget	Difference	Amendment	Amended FY 26 Budget Amount
Revenue:						
	Sponsorships & Individual Tickets	$ 13,515	$ -	$ (13,515)	$ 13,515	$ 13,515
	Other Sponsorship - in-kind	14,000	-	(14,000)	14,000	14,000
	Total Revenue	**$ 27,515**	**$ -**	**$ (27,515)**	**$ 27,515**	**$ 27,515**
Expenditures:						
	Venue, Catering, & AV	$ 18,150	$ -	$ (18,150)	$ 18,150	$ 18,150
	Graphic Design Services	9,365	-	(9,365)	9,365	9,365
	Total Expenditures	**$ 27,515**	**$ -**	**$ (27,515)**	**$ 27,515**	**$ 27,515**

Attachment

Resolution Number 01-26 adopting
FY 2026/2027 Supporting
Foundation Budget

1955 Chicago Avenue, SU 200
Riverside, CA 92505
(951) 405-6700
wrcog.us

RESOLUTION NUMBER 01-26

A RESOLUTION OF THE BOARD OF DIRECTORS OF THE WESTERN RIVERSIDE COUNCIL OF GOVERNMENTS SUPPORTING FOUNDATION ADOPTING THE FISCAL YEAR 2026/2027 SUPPORTING FOUNDATION BUDGET

WHEREAS, the Western Riverside Council of Governments' Supporting Foundation ("Supporting Foundation") was created to allow for the Western Riverside Council of Governments ("WRCOG") to apply for and receive grant funding that supports the efforts of WRCOG's various programs; and

WHEREAS, the Board of Directors has reviewed and approves the Supporting Foundation Fiscal Year 2026/2027 Budget.

NOW, THEREFORE, BE IT RESOLVED by the Board of Directors of the Western Riverside Council of Governments' Supporting Foundation as follows:

Section 1. Recitals. The above recitals are incorporated herein by this reference.

Section 2. Final Budget. The Board of Directors hereby approves and adopts the Supporting Foundation Fiscal Year 2026/2027 Budget, attached hereto as Exhibit A.

PASSED AND ADOPTED by the Western Riverside Council of Governments' Supporting Foundation Board of Directors on May 4, 2026.

_____
Brenda Dennstedt, President
WRCOG Supporting Foundation

_____
Christopher J. Gray, Secretary
WRCOG Supporting Foundation

Approved as to form:

_____
Steven DeBaun
WRCOG Legal Counsel

AYES: _____ NAYS: _____ ABSENT: _____ ABSTAIN: _____

EXHIBIT A

Western Riverside Council of Governments
Supporting Foundation
Fiscal Year 2026/2027 Budget

		2027 Proposed Budget
Revenue:		
	Sponsorships & Individual Tickets	$ 326,550
	Tribal Sponsorship - in-kind	55,000
	Other Sponsorship - in-kind	66,500
	Total Revenue	**$ 448,050**
Expenditures:		
	Event Support	$ 152,550
	Venue, Catering, & AV	185,345
	Graphic Design Services	51,100
	Hotel Expenses	18,000
	Program/Promotional Expenses	28,000
	Total Expenditures	**$ 434,995**
	Excess Revenue/(Expense)	**$ 13,055**

EXHIBIT A

Western Riverside Council of Governments
Supporting Foundation
Fiscal Year 2026/2027 Budget

General Assembly

		2027 Proposed Budget
Revenue:		
	Sponsorships & Individual Tickets	$ 305,000
	Tribal Sponsorship - in-kind	55,000
	Other Sponsorship - in-kind	52,500
	Total Revenue	**$ 412,500**
Expenditures:		
	Event Support	$ 149,200
	Venue, Catering, & AV	164,345
	Graphic Design Services	41,400
	Hotel Expenses	18,000
	Program/Promotional Expenses	26,500
	Total Expenditures	**$ 399,445**
	Excess Revenue/(Expense)	**$ 13,055**

Women's Forum

		2027 Proposed Budget
Revenue:		
	Sponsorships & Individual Tickets	$ 21,550
	Other Sponsorship - in-kind	14,000
	Total Revenue	**$ 35,550**
Expenditures:		
	Event Support	$ 3,350
	Venue, Catering, & AV	21,000
	Graphic Design Services	9,700
	Hotel Expenses	-
	Program/Promotional Expenses	1,500
	Total Expenditures	**$ 35,550**
	Excess Revenue/(Expense)	**$ -**

Western Riverside Council of Governments Joint Meeting of the WRCOG Executive Committee and Supporting Foundation Board of Directors

Staff Report

Subject: Energy Resilience Plan 2.0 Final Deliverables

Contact: Daniel Soltero, Program Manager, dsoltero@wrcog.us, (951) 405-6738

Date: May 4, 2026

Recommended Action(s):

1. Receive and file.

Summary:

The Energy Resilience Plan (ERP) 2.0 is a forward-looking roadmap designed to strengthen community resilience and safeguard essential municipal facilities from power disruptions. By advancing clean energy microgrids and community resilience centers, the ERP 2.0 positions WRCOG's member agencies to align with California's climate and energy goals and future funding opportunities for implementation.

Purpose / WRCOG 2022-2027 Strategic Plan Goal:

The purpose of this item is to provide information on the findings and final deliverables of the ERP 2.0. This item aligns with WRCOG's 2022-2027 Strategic Plan Goal #5 (Develop projects and programs that improve infrastructure and sustainable development in our subregion).

Discussion:

Background

Large swaths of California have been subject to power outages over recent years due to impacts from extreme weather events and climate hazards, either directly affecting infrastructure or necessitating public safety power shutoffs. The western Riverside County subregion faces a variety of intensifying climate hazards including extreme heat, wildfire risk, and public safety power shutoffs that threaten both community wellbeing and critical infrastructure. These risks are compounded by social vulnerabilities, such as high poverty rates, lower educational attainment, and high concentration of disadvantaged communities. As previously identified by WRCOG's Resilient IE project, these climate and socioeconomic pressures underscore the urgent need for climate and energy resiliency solutions.

In response to power outages at critical municipal facilities and the findings of the Resilient IE project,

WRCOG developed an ERP in 2022 which explored feasibility of developing microgrids as an energy resiliency strategy. With the California Resilience Challenge Grant, the ERP developed a site identification and prioritization method and developed four microgrid feasibility studies for member agency-owned facilities. At the conclusion of the ERP, staff were directed by the Executive Committee to seek funding opportunities to advance the identified projects further along in the design process and conduct energy resilience planning activities.

In 2023, WRCOG was awarded an Adaptation Planning Grant through the Integrated Climate Adaptation and Resiliency Program (ICARP) administered by the Governor's Office of Land Use and Climate Innovation, formerly Office of Planning & Research. The $471,000 grant was active from December 2023 through February 2026 and funded the development of WRCOG's ERP 2.0.

With the ICARP Adaptation Planning Grant, WRCOG initiated ERP 2.0 to build upon the initial ERP by conducting additional feasibility studies to determine if microgrids and community resilience centers could be implemented at member agency-owned facilities. The deliverables of the ERP 2.0 will provide a technical and programmatic assessment of each selected site for either a microgrid or community resilience center, community engagement summaries, a Regulatory Memo exploring challenges and barriers for microgrid development, and an Implementation Plan that outlines funding and development strategies. The ERP 2.0 culminates in a comprehensive roadmap enabling WRCOG and its members to move the microgrid and Community Resilience Centers (CRC) feasibility studies from planning to implementation.

Present Situation

In February 2026, WRCOG completed development of the ERP 2.0, which assessed 16 facilities for microgrids and/or community resilience centers across 13 member agencies, developed an Implementation Plan, prepared a Regulatory Memorandum for microgrid development, and engaged with the community through outreach and marketing efforts. The ERP 2.0 was developed in three phases: 1) identification and prioritization of critical facilities for microgrids and resilience centers with a focus on disadvantaged communities, 2) community outreach and engagement to gather lived experiences regarding climate hazards and power outages and feedback on programs and services that could increase resiliency, and 3) conduct microgrid and resilience center feasibility studies.

Starting in 2024, WRCOG coordinated with member agencies to identify, prioritize, and select facilities for a microgrid-only or a microgrid and CRC feasibility study. Staff collected and reviewed climate and social vulnerabilities and impacts through a comprehensive review of regional, state, federal, utility, and local data sources. Over 100 candidate sites were analyzed to identify high-impact sites where microgrids and CRCs can be used as a response to climate hazards and power outages. Each site was scored and ranked based on climate hazard risk, social vulnerability, power reliability, and building characteristics, which resulted in a list of potential high-impact sites. Member agencies were consulted to make a final selection of which site they would move forward with and what type of feasibility study to receive.

The feasibility studies provided through the ERP 2.0 serve as preliminary technical and financial assessments that member agencies can use to make an informed decision on whether to proceed to the next phases of microgrid and CRC implementation, including committing to detailed engineering design and further investment. In total, eight sites were selected to receive a microgrid-only feasibility study, and eight sites were selected for microgrid and CRC feasibility studies. The feasibility studies provide

key insights and findings from the evaluation of the sites energy demand profile, distributed energy resources, including solar photovoltaic systems and battery energy storage systems, and outlines the financial implications for a variety of project scenarios. The feasibility studies and their results can be referenced in Attachments #1 and #2 to this Staff Report.

To ensure that this project is engaged with the community and integrated community feedback and input, WRCOG partnered with GRID Alternatives, a nonprofit organization that provides solar power installations and clean energy job training to underserved communities. Between 2024 and 2025, WRCOG and GRID Alternatives created an outreach plan, developed marketing materials and promotional products, and surveyed the community at tabling and community events throughout the subregion. The goal was to raise awareness of climate hazards affecting western Riverside County, learn from the community on their experiences with climate hazards and emergencies, and receive input on the types of programs and services that would make a CRC helpful and increase community resiliency.

Another major deliverable of the ERP 2.0 is the Implementation Plan, which is a roadmap that outlines the various phases of microgrid and CRC development from feasibility through construction and commissioning (Attachment #3). The Implementation Plan describes each phase and provides considerations, estimated timelines, and insights to each phase of development. It also explores contracting models for microgrid development, as well as governance and partnership structures for community resilience centers. This document includes a Funding and Financing Strategies chapter which lists various funding sources including federal and state grants and incentives, local and utility incentives and programs, as well as financing tools.

To complement the Implementation Plan, WRCOG also developed a Regulatory Memo titled "Pathways and Pitfalls to Local Government Microgrid Adoption to Address Reliability/Resiliency Issues" (Attachment #4). This Memo provides an overview of the opportunities, challenges, regulatory issues, and economics associated with developing a microgrid at public sector facilities in southern California. If member agencies are to develop a microgrid, it is critical to understand the legal and regulatory implications of developing a microgrid, as there are rules and regulations that apply from entities such as the California Public Utilities Commission and Southern California Edison. If implemented, the solutions identified in the ERP 2.0 would also assist member agencies with progress towards meeting state mandates such as Senate Bill (SB) 350 (2015) by prioritizing energy efficiency improvements, SB 379 (2016) by advancing climate resilience strategies, and SB 100 (2018) by implementing renewable energy generation and clean energy microgrids.

While prior documents and studies had identified resilience hubs and backup as adaptation strategies, WRCOG's ERP 2.0 advances that work by systematically identifying high-impact sites where microgrids and CRCs can be used to respond to climate risks and hazards. In conclusion, WRCOG provides this ERP 2.0 and its deliverables so that member agencies can determine if they want to take the next steps towards microgrid and CRC development. Staff are coordinating with member agencies to determine if they would like to move forward with a microgrid or CRC project, including taking any of the next steps as detailed in the feasibility study or Implementation Plan, and to identify potential partnership opportunities where WRCOG can assist member agencies.

Prior Action(s):

April 16, 2026: The Technical Advisory Committee received and filed.

April 9, 2026: The Public Works Committee received and filed.

August 7, 2023: The Executive Committee 1) accepted the ICARP Adaptation Planning Grant award; 2) authorized the Executive Director to execute the Grant Agreement, substantially as to form and subject to legal counsel's review and approval, with the Governor's Office of Planning and Research; and 3) authorized the Executive Director to execute the Partnership Agreement, substantially as to form and subject to legal counsel's review and approval, with GRID Alternatives Inland Empire.

Financial Summary:

Activities related to the Energy Resilience Plan 2.0 are included in the Fiscal Year 2025/2026 Budget under Program code 2250 in the General Fund (110).

Attachment(s):

Attachment 1 - WRCOG Energy Resilience Plan 2.0 Microgrid Feasibility Studies.pdf

Attachment 2 - WRCOG Energy Resilience Plan 2.0 Community Resilience Center Feasibility Studies.pdf

Attachment 3 - WRCOG Energy Resilience Plan 2.0 Implementation Plan.pdf

Attachment 4 - WRCOG Energy Resilience Plan 2.0 Regulatory Memo: "Pathways and Pitfalls to Local Government Microgrid Adoption to Address Reliability/Resiliency Issues".pdf

Attachment

WRCOG Energy Resilience Plan 2.0
Microgrid Feasibility Studies

AECOM



Microgrid Feasibility Study
City of Eastvale

Site:
Riverside County Fire Department Station No. 31
14491 Chandler Street, Eastvale, CA 92880

February 2026

Delivering a better world

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Executive Summary

This study appraises the viability and benefits of distributed energy resource implementation scenarios at the subject site. Four scenarios were developed and compared, key metrics summarized below:

Case	*Components*	*CAPEX* *($)*	*Utility Savings*		*Payback Period* *(years)*	*GHG Reduction* *($MTCO_2e$)*
			Demand *(kWh)*	*Bills* *($)*		
1	PV	$100k	(42%)	($10k)	8	17
2	PV + BESS	$190k	(65%)	($15k)	9	17
3	BESS	$65k	--	--	--	--
0	Business as usual, no addition(s)	--	--	--	--	--

Note: All values are approximate and subject to final design and incentive approval..

- **Case 1: Photovoltaic (PV) array** – Introduces onsite generation capability.
- **Case 2: PV array + battery energy storage system (BESS)** – Energy storage capability enables additional self-sustaining (i.e., islanding) capacity. Higher upfront costs.
- **Case 3: BESS** – Enables relatively shorter-term resilience capability. Somewhat redundant considering existing diesel generator set (125 kW) onsite.
- **Case 0: Business-as-usual** – Maintains currently utility dependence. No additional resilience benefits.

Considering the above, this study concludes that the **Case 1 (PV)** scenario is the most suitable and cost-effective path forward, striking a balance between resilience capabilities, technical feasibility, and financial performance.

Recommended Next Steps

1. Advance to a 30% design phase with detailed site and structural assessments
2. Procure vendor-specific quotations to refine cost estimates beyond what is provided in this study
3. Initiate permitting and interconnection applications with Southern California Edison under the current Net Energy Metering tariff (NEM 3.0)
4. Secure federal incentives, specifically the 30% Investment Tax Credit (direct pay), to lower upfront costs
5. Prepare procurement and construction planning, targeting installation within the next budget cycle.

The goal is that with these data-driven microgrid feasibility assessment findings, the City of Eastvale can make an informed decision regarding an appropriate resilience-improving investment at the subject site.

Background

Purpose

In recent years, especially within the past decade, the impacts of extreme heat and wildfires have been profound through the Inland Empire. Power service disruptions have been increasing in frequency and severity throughout Riverside County, affecting the availability of essential services and community resources.

In 2023, the Western Riverside Council of Governments (WRCOG) received an award (Grant Agreement OPR23145) from the Adaptation Planning Grant Program of the California Governor's Office of Land Use & Climate Innovation Integrated Climate Adaptation and Resilience Program. This program provides funding to help fill local, regional, and tribal planning needs, provides communities the resources to identify climate resilience priorities, and supports the development of a pipeline of climate-resilient infrastructure projects across the state.

As part of this grant-funded project, the Energy Resilience Plan 2.0, WRCOG commissioned microgrid feasibility studies for its member agencies. These studies serve to provide valuation of a potential microgrid at a community-essential facility, as designated by the member agency.

The site selected for the City of Eastvale is the Riverside County Fire Department Station No. 31.

This study presents key insights and findings from the evaluation of distributed energy resource (DER) scenarios, including photovoltaic (PV) array and battery energy storage system (BESS) components, at the subject site. It includes analysis of the site's historic energy demand profile and appraises potential PV array and BESS sizing and siting scenarios accordingly. Notably, the study includes assessment of the generation and storage requirements to support the site's critical loads to enable resilience for a specified number of hours during power service disruptions.

Furthermore, this study outlines the financial implications of self-generation, including estimated cost savings, return on investment (ROI), and potential financing options for the project.

It is important to note that this study serves as a preliminary technical and financial assessment. Its purpose is to provide the City of Eastvale with the information to make an informed decision on whether to proceed to next phases of microgrid implementation before committing to detailed engineering design and further investment.

Adaptation Planning Grant Program

As communities in California experience more frequent, prolonged, and severe impacts from climate change, communities and governments at all scales are developing strategies and implementing actions to build a climate-resilient future. However, many jurisdictions, especially under-resourced communities in California, lack the capacity, tools, guidance, and resources to effectively prepare for climate impacts.

The Adaptation Planning Grant Program addresses this capacity gap by providing funding to help fill planning needs, providing communities with the resources to identify climate resilience priorities, and supporting the development of climate resilience projects across the state. The Adaptation Planning Grant Program enables communities to climate risk and adaptation considerations into planning activities and prepare for climate readiness and resilience in the long term.

The Adaptation Planning Grant is part of the Integrated Climate Adaptation and Resilience Program (ICARP) housed within the Governor's Office of Land Use and Climate Innovation. ICARP advances statewide climate adaptation and resilience by coordinating investments, partnerships, and climate science to ensure people, natural systems, and the built environment are protected, prepared, and thrive in the face of climate change.

Through direct and equity-focused investments and resources, ICARP helps build climate adapted and equitable communities in California, with a focus on solutions that address the impacts of climate change and reduce greenhouse gas emissions. ICARP works to advance these priorities across all levels of government by developing

actionable science and research; providing guidance, tools, and technical assistance; and administering climate resilience-focused grant programs.

Learn more: https://lci.ca.gov/climate/icarp/

Modeling Methodology

This section defines the criteria for sizing the PV array and BESS system components, detailing general parameters, technical requirements, and expected performance criteria.

PV Modeling

1. **Data Inputs**
    - **Solar Resource**: Hourly or sub-hourly irradiance data (e.g., typical meteorological year or on-site measurements)
    - **Site-Specific Factors**: Tilt angle, azimuth, shading analysis, and available roof/ground space
2. **Simulation Approach**
    - Use of HelioScope software to estimate hourly PV production
3. **Sizing Criteria**
    - **Capacity Target**: The sizing criteria are based on 110% of the facility's current annual energy consumption. This approach aims to fully offset the facility's energy usage with the PV array while incorporating an additional 10% capacity to accommodate future demand growth. However, the final system capacity is constrained by the area designated as available by the client.
    - **Performance Ratio**: Evaluate Performance Ratio to ensure consistent system output
    - **Energy Production**: Hourly, daily, monthly, and annual PV generation forecasts
    - **Load Matching**: Amount of PV energy that directly offsets site load vs. excess exported to the grid

BESS Modeling

1. **Data Inputs**
    - **Load Profile**: Detailed electricity consumption and demand patterns
    - **PV Production Profile**: From the PV modeling results
    - **Energy Duration for Resilience**: Determine the critical loads that the BESS will support during islanding operations
2. **Operational Modes**
    - **Energy Shifting / Excess PV Storage**: Battery charges when PV output exceeds site demand, discharges when site demand is high.
    - **Resilience (Standalone BESS)**: Sized to support critical loads during outages
3. **Sizing Criteria**
    - **Capacity (kWh)**: Based on required autonomy (energy shifting, peak shaving, or resilience duration)
    - **Max Discharge/Charge Rate (kW)**: Aligned with site load peaks, PV generation surpluses, and emergency power needs
4. **Simulation Approach**
    - Hourly or sub-hourly dispatch modeling to maximize economic benefit (e.g., demand charge reductions or avoided peak rates)

- Incorporate battery round-trip efficiency, self-discharge, and operational constraints (e.g., partial charge strategies)

5. **Output**

   - **Discharge/Charge Profiles**: Hourly modeling of how the battery is utilized
   - **Cost Savings**: Reduction in energy and demand charges or avoided grid cost
   - **Backup Duration**: If sized for resilience, the total hours/days of critical load coverage

Assumptions

AECOM collected facility data through a request for information process. Energy consumption factors and facility characteristics were identified and integrated in analysis. AECOM used these combined datasets to confirm energy utility consumption baselines.

In performing the analysis, AECOM made the following assumptions:

- This report refers to the site Riverside County Fire Department Station No. 31, located at 14491 Chandler Street, Eastvale, CA 92880.
- The monthly and annual electricity consumption is determined using load profile data in the client-provided file "SCE_Usage_8011228244_08-01-24_to_08-31-25.xlsx." This file contains 35,040 load profile data points, which are then consolidated into an 8760 load profile dataset.
- AECOM utilized the Levelized Cost of Energy (LCOE) for the installed cost per watt of PV installations and BESS, as sourced from the National Laboratory of the Rockies (NLR). This data was used to estimate the hypothetical cost of installing the PV array and BESS at the site, as detailed in this report. For an accurate cost estimation, it is necessary to obtain vendor quotes, which are subject to change due to market-dependent time windows. These quotations are typically conducted during the 60% design phase, at which point there is an understanding of the specific equipment ratings and brands to be used.
- This report evaluates the site's existing electrical infrastructure using customer-provided data on the main breaker and bus capacity, as documented in the client-provided file "*Electrical Single Line Diagram*.pdf." AECOM has assessed whether the existing electrical system can support the proposed PV array and BESS installation. However, as this is a feasibility study, an on-site assessment is required for a definitive determination. A site visit should be conducted during the advanced design phase, typically at the 30% design stage, to confirm site-specific conditions.
- AECOM has estimated the potential PV generation capacity based on the client-identified available area, as documented in the client-provided file "*No-Go Areas for PV.pdf*." However, a site assessment is required in later project phases, typically at the 30% design stage, to ensure that the site has the necessary infrastructure for PV array installation. This includes evaluating civil structures, load-bearing capacity, particularly for rooftop installations, and other critical conditions necessary for successful implementation.
- This report uses a regionalized estimate of general production (kWh) to calculate the amount of greenhouse gas emissions avoided through PV generation. The calculation is based on the U.S. EPA Emissions & Generation Resource Integrated Database (eGRID).

AECOM utilized the following tools in conducting the analysis:

- AECOM Internal Tools: Proprietary tools developed by AECOM for analyzing energy patterns and evaluating system performance in simulated environments. These tools are designed to assess energy costs for applications such as peak shaving, energy trading, etc. in DER implementations.
- HelioScope: Web-based software tool used for the design and performance analysis of photovoltaic systems. It combines system layout design with energy simulation, allowing users to model rooftop, ground-mounted, and canopy PV installations. The software factors in module placement, tilt, azimuth, shading, and local weather data to provide accurate estimates of system capacity and expected energy generation.

Site Information

This study is conducted for Riverside County Fire Station No 31, located in Eastvale, California at 14491 Chandler Street. The fire station currently consumes about **79,482 kilowatt-hours** (kWh) **per year**, with a recorded maximum daily consumption of 395 kWh on June 7, 2025, and the highest monthly consumption in August 2025 at 8,368 kWh.

In terms of electrical infrastructure, the site has a 600 A main bus with a 400 Amp (A) distribution panel (DP), a short-circuit rating of 42 kA, and a connected load of approximately 133 kVA (~370 A). The system is operating within bus limits, leaving about 30 A (~10 kilovolt-ampere [kVA]) of spare capacity before reaching maximum load. It also includes available spare breakers and provisions for a future EV charging panel, allowing limited expansion.

For resilience, the system has a 125 kilowatt (kW) diesel generator (208/120 volt [V], 3-phase, 4-wire) connected through a 400 A automatic transfer switch (ATS), designed to support critical loads. It includes a control panel, remote alarms, battery charger, and load bank, ensuring automatic backup. Notably, it cannot fully cover 100% of the site's total load.



Figure 1. Site Location

The user has identified no-go areas for PV including a 36-inch setback from roof peaks for firefighter access and building frontage zones along visible roof edges. These restricted areas limit PV placement while ensuring safety and code compliance.

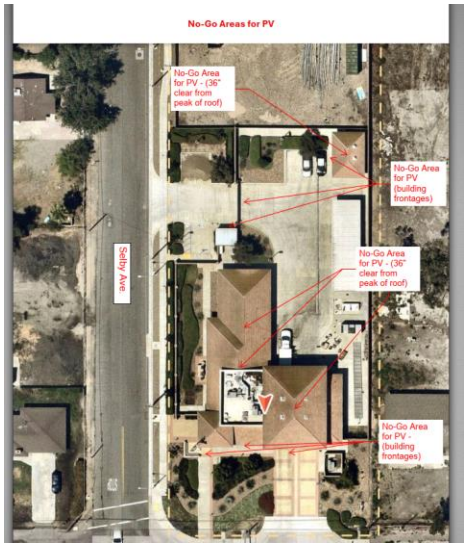


Figure 2. No-Go Areas for PV

Incentive Programs

AECOM has identified three key incentive programs that could benefit the subject site, focusing on renewable energy production and advanced energy storage systems.

The Investment Tax Credit (ITC) and Production Tax Credit (PTC) are federal incentives that reduce the cost of renewable energy projects. ITC offers a tax credit based on a percentage of upfront investment costs, while PTC provides a per-kilowatt-hour credit for electricity generated over time.

Production Tax Credit

Under this initiative, the project is eligible for a tax credit ranging from 0.3 cents to1.5 cents per installed kWh. The specific value of the credit is determined by several factors, including the project's adherence to certain requirements such as complying with labor standards and using domestic materials.

The PTC program pays for each kilowatt-hour produced over a 10-year period, with government entities receiving the benefit as direct pay instead of a tax credit. For this project, with an estimated 89,032 kWh per year, the best case at 1.5 ¢/kWh would yield about $1,335 annually, totaling around $13,350 over 10 years.

Investment Tax Credit

The City can take advantage of either the ITC or the PTC, but both cannot be utilized simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

This evaluation presumes that a 30% credit of the proposed renewable energy system’s capital cost will be accessible to reduce initial capital expenses and enhance potential payback periods.

The ITC offers an additional 10% credit for projects located in low-income communities. However, this site is outside a designated low-income area according to the 2016–2020 census tract (see Figure 3), so it does not qualify for the extra 10% and is limited to the standard 30% credit.

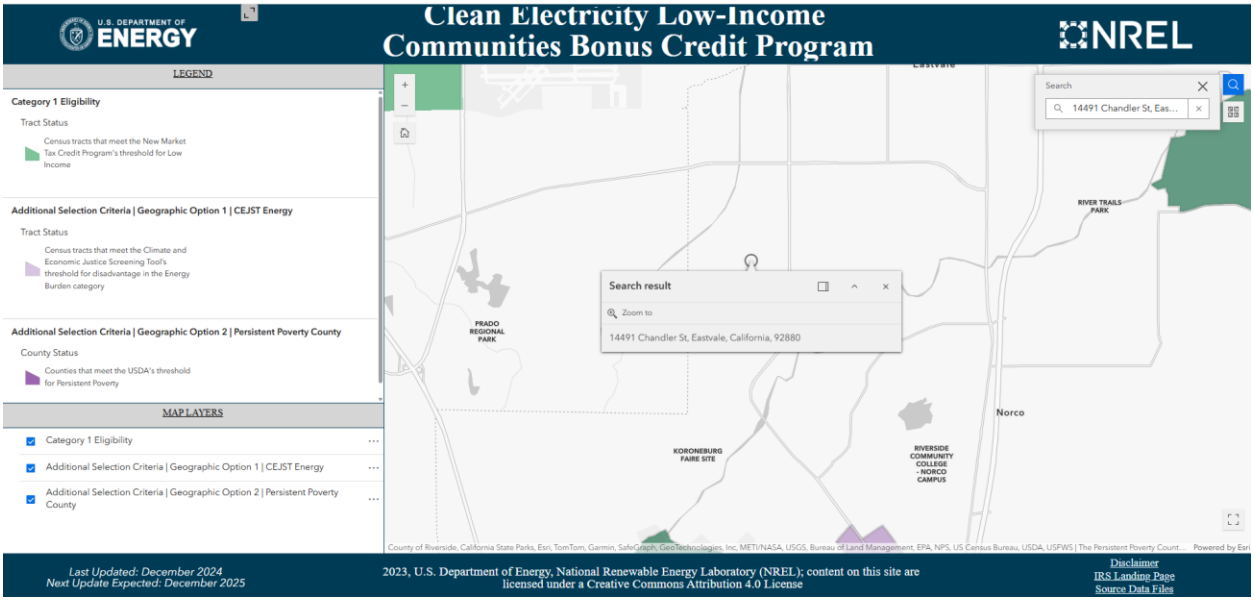


Figure 3. Clean Electricity Low-Income Communities Bonus Credit Program Map

NLR estimates capital expenditure (CAPEX) for commercial PV at $1.75–$2.00 per Watts direct current (W-DC). For this study, a 52 kilowatts direct current (kW-DC) system is projected, which represents about 110% of the site’s annual consumption (the site uses ~79,482 kWh/year, while the system would generate ~89,032 kWh/year). Based on these CAPEX values, the installation cost would range from $91,000 to $104,000. For government entities, the ITC is received as direct pay rather than a tax credit, with 30% of the project cost amounting to approximately $27,000–$31,000.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) is a State of California incentive designed to support the installation of energy storage systems by reducing upfront costs. It offers two main categories of support:

- Equity Rebate: Provides a high incentive rate for projects located in Disadvantaged Communities (DACs) or serving low-income customers. The key requirement is that the site must be within a DAC census tract or meet low-income eligibility criteria.
- Equity Resilience Rebate: Offers an even higher incentive for critical facilities such as fire stations, police, medical centers, or emergency shelters. To qualify, the project must be located in a DAC and also be in an area at risk of Public Safety Power Shutoffs (PSPS) or high wildfire threats.

Since the city project site is located outside of a DAC area, it does not meet the prerequisites to qualify for the equity rebate neither the Equity Resilience rebate.

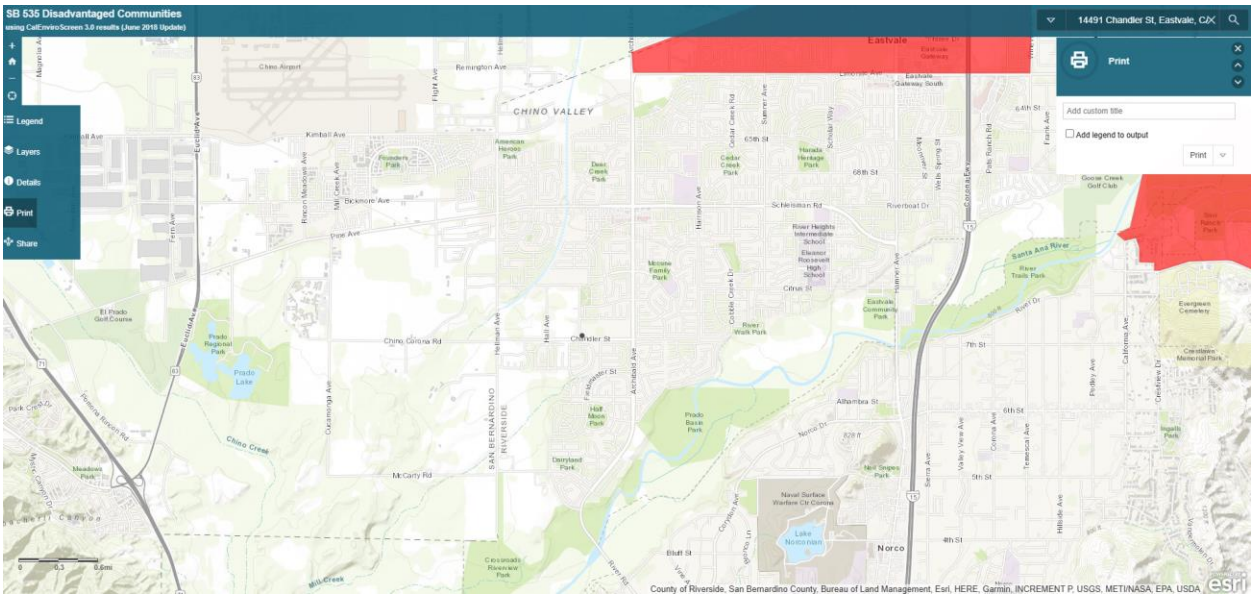


Figure 4. SB 535 Disadvantaged Communities Map

Scenarios & Analysis

Case 0: Current Situation (Baseline)

Tariff & Contract Type

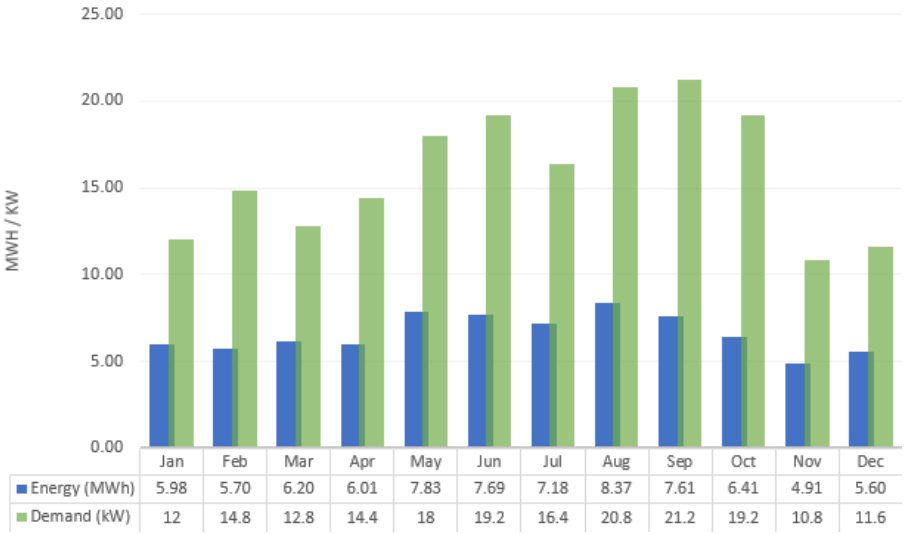
The site is currently served by Southern California Edison (SCE) under the TOU-GS-2 Option D tariff, which is designed for small to medium commercial customers. This rate structure separates costs into energy charges (based on kilowatt-hours consumed) and demand charges (based on the highest kilowatt demand registered during the billing cycle). In addition, prices vary by time-of-use periods—on-peak, mid-peak, and off-peak—so the timing of energy use significantly affects overall costs.

Being on this tariff means the site's operating expenses are directly tied not only to how much energy is consumed but also to when it is consumed and how high the peak demand reaches.

The tariff cost presents the costs as totals (delivery + bundle). The prices were used as the basis for this study. While they may fluctuate slightly month to month depending on market conditions, these variations are generally minor.

Monthly & Annual Energy Consumption and Demand

The facility currently consumes 79,482 kWh annually, with August being the highest month at about 8,368 kWh and November the lowest at about 4,906 kWh. In terms of demand, September records the peak at around 21 kW, while November is the lowest at about 11 kW. The following graph presents this historical data for the 2024–2025 period.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Energy (MWh)	5.98	5.70	6.20	6.01	7.83	7.69	7.18	8.37	7.61	6.41	4.91	5.60
Demand (kW)	12	14.8	12.8	14.4	18	19.2	16.4	20.8	21.2	19.2	10.8	11.6

Figure 5. Historic Site Energy Profile

Monthly & Annual Energy Costs

The site currently spends about $24,182 per year, with approximately $16,202 in energy costs and $7,981 in demand charges, based on tariff TOU-GS-2 simulation. For this analysis, we are focusing only on energy and demand costs, as these are the components directly impacted by the installation of a PV system.

Case 1: PV Only

Installed Capacity & Location

The PV system for the site was sized to offset approximately 110% of current consumption, with the goal of fully offsetting present usage while reserving about 10% additional capacity for future growth. The placement areas for the PV installation were identified according to customer requirements. The system capacity is estimated at 52.17 kW direct current (DC) / 44.16 kW alternating current (AC), with an expected annual production of about 89,032 kWh.

Figure 6 presents the modeled energy production throughout the year, and Figure 7 identifies the designated PV installation areas on the site.

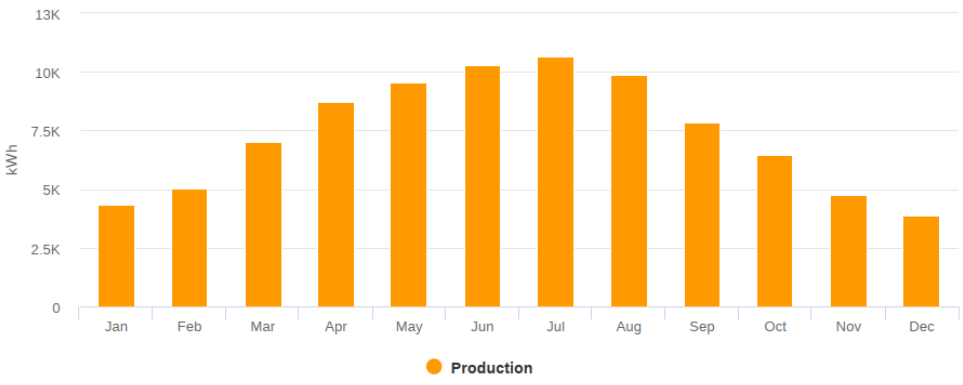


Figure 6. Modeled PV Production



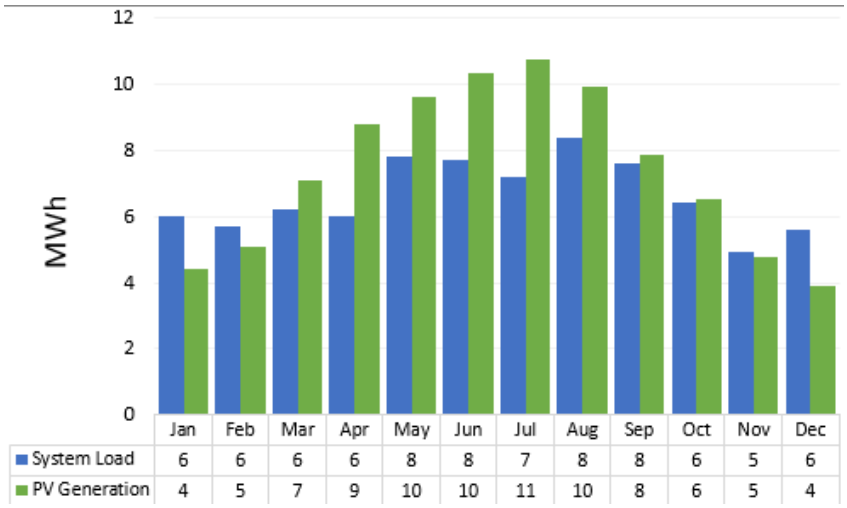
Figure 7. Modeled PV Installation Areas

Modeled PV Production

The modeled PV system is projected to generate an average of 7,500 kWh per month, with an estimated annual production of 89,032 kWh.

This scenario doesn't include a BESS, so the excess energy produced need be exported to the utility, which requires entering a Net Energy Metering (NEM) contract with the utility service provider. Under the currently available NEM tariff, NEM 3.0, exported electricity is credited at dynamic rates that vary by month, hour of day, and weekday, ranging from as low as $0.01/kWh during midday hours to over $1.00/kWh during peak evening hours in high-demand months like August and September. This study has calculated projected benefits from this arrangement.

Figure 8 compares historic monthly energy consumption and modeled PV generation. Not all solar energy will be consumed on-site, as excess daytime production may exceed demand and be exported to the grid, while nighttime demand cannot be covered since there is no generation after sunset and no battery to store the excess in this scenario.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
System Load	6	6	6	6	8	8	7	8	8	6	5	6
PV Generation	4	5	7	9	10	10	11	10	8	6	5	4

Figure 8. Modeled PV Output vs. Site Demand

Capital Expenditures

Based on NLR benchmark CAPEX values for commercial rooftop solar, the estimated cost to install a 52 kW DC PV system in Riverside County, California falls in the range of $1.75 to $2.00 per watt DC. This translates to a total investment of **approximately $91,000 to $104,000 for the complete system**.

These figures include typical equipment, installation, and soft costs, reflecting average market conditions for commercial-scale projects. Actual costs may vary slightly depending on site-specific conditions such as roof structure, permitting, interconnection requirements, and labor. However, the NLR benchmarks provide a reliable basis for estimating the capital cost of a system of this size and type in the region.

Operating Expenses

According to NLR's 2024 benchmark data, the annual operations and maintenance (OPEX) cost for commercial rooftop PV systems is about $19 per kW-DC. For a 52 kW DC system, this translates to an estimated **yearly OPEX** of roughly **$988**, covering routine maintenance, monitoring, and related operational expenses.

Economic Metrics

The analysis shows that installing a PV system at the site under NEM3 provides measurable financial benefits by offsetting both energy and demand charges. Without solar, the facility currently spends about $24,182 annually on utility costs. With the PV system in operation, the energy cost is reduced to approximately $8,396 per year, while the demand cost drops to about $6,914 per year. In addition, the system generates excess electricity during the day that cannot be fully consumed on-site. Under NEM3 rules, this exported energy represents an additional benefit of roughly $1,221 annually.

Taken together, these reductions and export credits bring the facility's total utility bill down to **$14,090 per year**, achieving an **overall savings of about 41.7%** compared to current expenses

Payback Period and Return on Investment

The financial analysis shows that without PV, the facility spends approximately $24,182 per year on utility costs. With a 52 kW DC PV system installed, the annual cost is reduced to about $14,090, resulting in yearly savings of roughly $10,092. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system is estimated at $104,000, but with the 30% ITC direct pay, the net investment is reduced to approximately $72,800. In addition, the system carries an annual OPEX of $988, which slightly offsets the yearly savings. Taking these factors into account, the project generates a net benefit of about $9,100 per year after OPEX. This results in a **simple payback period of approximately 8 years**, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross Savings ($)	Net Savings after OPEX ($)	Cumulative Cash Flow ($)
1	10,092	9,104	-63,696
2	10,395	9,407	-54,289
3	10,707	9,719	-44,571
4	11,028	10,040	-34,531
5	11,359	10,371	-24,160
6	11,700	10,712	-13,448
7	12,051	11,063	-2,385
8	12,413	11,425	9,040
9	12,785	11,797	20,837
10	13,169	12,181	33,018
15	15,265	14,277	108,662
20	17,700	16,712	184,973

Table 1. Return on Investment w/ 3% Inflation: Case 1

Technical Feasibility

The existing electrical system consists of a 600 A switchboard at 208 V, 3-phase, with a 600 A main breaker. The proposed solar PV system is rated at 44 kW AC, which corresponds to approximately 122 A output and requires a 150 A backfeed breaker for interconnection.

According to NEC 705.12(B)(2)(3)(b), the sum of the main breaker and all backfed generation breakers must not exceed 120% of the bus rating. For a 600 A bus, this limit is 720 A. In the current configuration, the 600 A main breaker combined with the required 150 A PV breaker equals 750 A, which exceeds the code allowance.

To comply with code and safely integrate the PV system, an electrical upgrade is required. The most practical solution is to reduce the main breaker from 600 A to 500 A. This adjustment lowers the main contribution, allowing the PV breaker to be added while staying within the 120% rule, i.e., 500 A (main) + 150 A (PV) = 650 A ≤ 720 A (permitted)

This upgrade ensures the bus is not overloaded, maintains protection coordination, and allows the PV system to be interconnected in compliance with NEC requirements.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate **89,032 kWh per year**. Using the U.S. EPA's *Emissions & Generation Resource Integrated Database (eGRID)* factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:

- Carbon dioxide (CO_2): ~38,147 pounds (lbs) (≈17.30 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): ~38,282 lbs (≈17.36 metric tons) avoided annually
- Nitrogen oxides (NO_x): ~29.6 lbs (≈13.4 kg) avoided annually
- Sulfur dioxide (SO_2): ~1.8 lbs (≈0.8 kg) avoided annually

Case 2: PV + BESS

System Components

This scenario assumes the same PV array described in Case 1 and a BESS sized for surplus PV production.

The day with the highest energy surplus in our simulation occurred on February 4, 2025, during which the PV system produced 214.4 kWh, the site consumed 16.5 kWh, and the resulting surplus was 197.9 kWh. To size the BESS, we take this maximum daily surplus as the baseline and add a 25% safety factor, bringing the required battery capacity to approximately 250 kWh.

This safety factor ensures that even under variations in production or demand, all excess solar energy generated during the day can be stored. The stored energy is then available for use at night or during periods when PV production does not fully cover the site's demand.

By doing so, every unit of solar energy produced on-site is consumed daily by the facility, preventing any export to the grid. As a result, the utility bill for both energy and demand charges can effectively be reduced to zero, with only fixed or non-energy charges remaining.

Modeled Energy Flows

By installing a 250 kWh battery, we ensure that all the energy generated on-site is consumed by the facility itself. The charge and discharge profile of the battery is designed so that any PV surplus during the day is immediately stored in the battery rather than exported to the grid. Later, if the site demand exceeds the PV generation while there is still energy stored in the battery, the deficit is supplied from the battery.

This operational strategy minimizes or even eliminates consumption from the utility, since the PV and battery combination is prioritized to cover the load at all times. On an annual basis, the system is expected to produce slightly more energy than the site requires, leaving a surplus of around 10%, but this excess is negligible in terms of the overall utility bill.

Capital Expenditures

According to NLR benchmark data, the **CAPEX** for a commercial-scale 52 kW DC rooftop PV system in Riverside, California is estimated at **$91,000 to 104,000**, based on installation costs of $1.75–2.00 per watt DC.

For storage, NLR's 2025 cost projections indicate a CAPEX of $350 per kWh for the high-cost scenario. Applying this benchmark to a commercial-scale 250 kWh battery system results in a total investment of approximately $87,500.

Together, the combined CAPEX for the PV and BESS systems is estimated at $178,500 to 191,500, representing the expected upfront investment for a commercial solar-plus-storage project of this size.

Operating Expenses

According to NLR benchmark data, the annual operations and maintenance (OPEX) cost for a commercial-scale 52 kW DC rooftop PV system is estimated at $988.

For storage, NLR data indicates that a commercial-scale 250 kWh battery system has an annual OPEX of about $1,000.

Together, the **combined OPEX for the PV and BESS** systems is approximately **$1,988 per year**, covering routine maintenance, monitoring, and system management.

Economic Metrics

The analysis shows that installing a commercial-scale PV system paired with a 250 kWh battery at the site under NEM 3 provides substantial financial benefits by ensuring that nearly all solar energy produced is consumed on-site. During most of the year, PV generation exceeds the facility's consumption, and the surplus is stored in the BESS for later use. In some months, however — specifically January, February, November, and December — consumption is higher than production, leading to a residual energy cost of about $475. In contrast, in all other months, production exceeds consumption, resulting in surplus energy that, if exported under NEM 3 rules, would generate about $340 in credits. Balancing these two effects, the net annual energy cost would be approximately $135.

To remain conservative, this analysis assumes that 10% of annual energy costs remain due to efficiency losses, imperfect alignment of PV output and site load, and seasonal variability. Under this assumption, the annual energy cost is reduced from $16,202 (current energy portion of the bill) to about $1,620.

Demand charges are left unchanged at $6,914 per year, since reducing them requires more advanced dispatch strategies and is not assumed in this base case.

Taken together, the facility's total utility bill drops from $24,182 per year (without PV and BESS) down to approximately $8,534 per year, representing an overall savings of about 65%.

It is important to note that other charges—such as connection fees, requisite charges, and taxes—remain unaffected. This analysis focuses only on those bill components directly impacted by the installation of PV and BESS under the NEM 3 framework.

Payback Period and Return on Investment

The financial analysis shows that without solar and storage, the facility spends approximately $24,182 per year on utility costs. With a 52 kW DC PV system plus a 250 kWh BESS installed, the annual bill is reduced to about $8,534, resulting in yearly gross savings of roughly $15,648 in the first year. When accounting for modest 3% annual inflation, these savings increase gradually over time, further strengthening the project's economics.

The total capital cost of the combined PV + BESS system is estimated at $191,500, but with the 30% ITC direct pay, the net investment is reduced to about $134,050. In addition, the system carries an annual OPEX of roughly $1,988, which slightly offsets the yearly savings. Taking these factors into account, the project generates a net benefit of about $13,660 per year after OPEX in Year 1.

This results in a simple payback period of approximately 8–9 years, after which the facility continues to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross-Savings ($)	Net-Savings after OPEX ($)	Cumulative Cash Flow ($)
1	15,648	13,660	-120,390
2	16,117	14,129	-106,261
3	16,601	14,613	-91,648
4	17,099	15,111	-76,537
5	17,612	15,624	-60,913
6	18,140	16,152	-44,760
7	18,685	16,697	-28,064
8	19,245	17,257	-10,807
9	19,822	17,834	7,028
10	20,417	18,429	25,457
15	23,681	21,693	142,227
20	27,170	25,182	322,093

Table 2. Return on Investment w/ 3% Inflation: Case 2

Technical Feasibility

The existing electrical system consists of a 600 A switchboard at 208 V, 3-phase, with a 600 A main breaker. From this switchboard, a 400 A feeder breaker supplies the distribution panel “DP,” which in turn feeds multiple branch panels and building loads.

The proposed solar PV system is rated at 44 kW AC, corresponding to approximately 122 A output and requiring a 150 A backfeed breaker. In addition, a BESS rated at 250 kW with 50 kW charge/discharge capability is proposed, requiring an estimated 175 A breaker.

If interconnected on the load side at either the 600 A MSB or the 400 A DP, the combined contribution of the PV and BESS breakers, together with the existing main and feeder breakers, would exceed the NEC 705.12 120% bus rating rule. Specifically:

- At the 600 A MSB: 600 A (main) + 150 A (PV) + 175 A (BESS) = 925 A > 720 A allowed
- At the 400 A DP: 400 A (feeder) + 150 A (PV) + 175 A (BESS) = 725 A > 480 A allowed

In both cases, code compliance cannot be achieved with a simple load-side connection.

The most practical and viable solution is a supply-side interconnection (i.e., line-side tap) at the MSB, upstream of the 600 A main breaker. This approach removes the PV and BESS breakers from the 120% bus limitation, while still allowing protection coordination and metering requirements to be met. The interconnection must comply with NEC 240.21 (i.e., tap conductors) and utility interconnection requirements.

This solution ensures that the PV and BESS can be integrated without overloading existing buses, avoids costly breaker downsizing that would reduce available capacity to building loads, and maintains compliance with NEC and utility standards. Additionally, the BESS provides operational benefits such as resilience, peak shaving, and enhanced utilization of solar generation.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate **89,032 kWh per year**. Using the U.S. EPA *eGRID* factors for the CAMX subregion (California), this renewable generation will directly offset grid electricity and reduce site emissions as follows:

- Carbon dioxide (CO_2): ~38,147 lbs (≈17.30 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): ~38,282 lbs (≈17.36 metric tons) avoided annually
- Nitrogen oxides (NO_x): ~29.6 lbs (≈13.4 kg) avoided annually
- Sulfur dioxide (SO_2): ~1.8 lbs (≈0.8 kg) avoided annually

CASE 3: BESS Only

Critical Load Identification

AECOM have evaluated the single line diagrams provided by the client and identified the critical loads that must be supported by an emergency backup system. The selection of these critical loads is based on generally accepted standards and codes such as the NFPA 70 (National Electrical Code), NFPA 110 (Standard for Emergency and Standby Power Systems), and NFPA 72 (National Fire Alarm and Signaling Code), which require that life-safety systems, fire detection, alarms, communication, and essential facility functions be maintained during a power outage.

The following table summarizes the critical loads identified across the facility distribution panels:

Critical Load	Panel	VA	kW
Emergency Call Panel	A	500	0.50
Exterior Lights (Zone 1)	A	468	0.47
Exterior Lights (Zone 2)	A	423	0.42
Site Lights (Group 1)	A	487	0.49
Site Lights (Group 2)	A	522	0.52
Exhaust Fans EF-3 to EF-6	C	400	0.40
BACnet Controller	D	500	0.50
Smoke Fire Dampers	D	750	0.75
EF-2 Exhaust Fan	D	100	0.10
EF-7 Time Clock	D	100	0.10
FACP (Fire Alarm Control Panel)	E	500	0.50
Fire Alarm Bell	E	180	0.18
Smoke Detectors (Dorms)	E	250	0.25
Generator Alarm	E	500	0.50
Data Rack	E	180	0.18
Security Board	E	180	0.18
Telephone Backboard	E	360	0.36
CATV Head End	E	360	0.36
Fuel Dispensing System	E	500	0.50

Table 3. Critical Loads

Total Critical Load Requirement: 7,260 VA ≈ 7.26 kW

Required Backup Duration

For a fire station, maintaining continuous operation of alarm systems, emergency communications, lighting, and fuel dispensing is essential to guarantee mission readiness. According to NFPA 110 (Section 4.2 and 7.12.1), emergency power supply systems (EPSS) must provide a minimum of 2 hours of operation at full rated load. However, because fire stations are classified as critical public safety facilities, most Authorities Having Jurisdiction (AHJs) and best practice guidelines require at least 4 hours of backup capacity to ensure firefighters can respond to emergencies during extended outages.

Battery Capacity & Infrastructure

In this scenario, based on the evaluation of critical loads, we recommend a battery energy storage system with 60 kWh usable capacity and 20 kW continuous power. At the identified load of 7.26 kW, this system provides **approximately 8.3 hours of backup**, exceeding both the 2-hour minimum of NFPA 110 and the 4-hour benchmark commonly required for fire stations.

Capital Expenditures

Using cost benchmarks published by the National Laboratory of the Rockies (NLR), the estimated **capital cost** (CAPEX) for a 60 kWh / 20 kW battery energy storage system is approximately $**65,000**. This figure includes the battery cabinets, inverter/PCS, microgrid controller with ATS, installation, protections, and engineering.

Operating Expenses

The expected OPEX is about **$2,000 per year**, also based on NLR reference values. This covers preventive maintenance, monitoring software, and NFPA 110 testing requirements. Battery replacement is typically required after 10–12 years of service.

Return on Investment & Qualitative Benefits

While a conventional financial return ROI cannot be directly applied to this case, the value of a BESS for a fire station is usually framed in terms of resilience, reliability, and compliance. Such systems are designed to ensure uninterrupted operation of life-safety and mission-critical equipment, including fire alarms, communications, lighting, and fuel dispensing, during extended utility outages. The benefits include maintaining service continuity, safeguarding firefighter readiness, and protecting the surrounding community. Compliance with NFPA 110, NFPA 70, and NFPA 72 also reduces liability exposure and ensures that the facility meets recognized safety standards.

However, for this particular fire station, the installation of a battery energy storage system does not present a compelling case. The facility already operates with a 125 kW emergency generator, which is more than sufficient to sustain the identified critical load of approximately 7.26 kW. Given this existing capacity, the addition of a 60 kWh / 20 kW BESS as a resilience measure would provide little to no incremental benefit relative to cost. The generator fully covers the resilience requirement, and therefore the justification for a BESS here would not be technical necessity

Technical Considerations

The system should be configured as two 30 kWh cabinets in parallel, each with its own battery management system, connected to a microgrid controller and an ATS rated at 200 A or equivalent to the emergency panel. This ensures redundancy and reliable operation of life-safety, communications, and fuel dispensing equipment.

Protective measures include a dedicated ATS for emergency circuits, compliance with NEC Article 700 and 702, and listed breakers with arc-fault detection. Proper ventilation and clearances must follow manufacturer specifications. Integration with a monitoring platform (i.e., SCADA or equivalent) is recommended to track state of charge, log events, and support monthly and annual NFPA 110 testing.

Decision Matrix and Scenario Comparison

In order to determine the most appropriate scenario for the site, four scenarios were developed and analyzed: business as usual (Case 0), installing a PV system only (Case 1), installing PV with a BESS (Case 2), and installing a BESS only (Case 3). Each case was evaluated in terms of resilience value, capital and operating expenditures, energy savings, payback period, and technical feasibility. The decision matrix summarizes the comparative performance of these options.

Criteria	Case 0: Baseline	Case 1: PV Only	Case 2: PV + BESS	Case 3: BESS Only
Resilience Benefit	None	Limited (daytime only)	Moderate (self-consumption, some coverage)	High (but redundant due to existing 125 kW generator)
CAPEX ($)	0	$91k – $104k	$178k – $192k	~$65k
OPEX ($/yr)	Current $24k	~$988	~$1,988	~$2,000
Annual Utility Bill ($)	~$24,182	~$14,090	~$8,534	~$24,182 (no reduction)
Annual Savings ($)	–	~$10,092	~$15,648	Minimal (non-financial)
Payback Period	–	~8 years	~8–9 years	No ROI
GHG Reduction	None	~17 $MTCO_2e$ avoided annually	Same as Case 1	None
Technical Feasibility	Already in place	Requires breaker adjustment	Requires breaker + storage integration	Technically feasible but unnecessary

Table 4. Scenario Comparison

Conclusion

Based on the comparative analysis, **Case 1 (PV only)** emerges as the preferred scenario. While Case 2 (PV + BESS) delivers higher annual savings and nearly eliminates energy costs, the BESS significantly raises capital costs and extends complexity, without offering proportional value under the site's current conditions. Case 3 (BESS only) was dismissed because the fire station already has a 125 kW generator, more than sufficient to cover the identified 7.26 kW critical load, making an additional BESS redundant for resilience purposes.

Therefore, Case 1 strikes the best balance between resilience benefit, cost requirement, operational savings, and practicality. It increases the resilience capability of this essential service facility, reduces the facility's utility bill by approximately 42%, has a relatively short payback period of 8 years, meaningfully reduces greenhouse gas emissions, and leverages existing infrastructure with only minor electrical upgrades. For this site, the benefits of adding a BESS are somewhat compromised by the existing diesel generator set and the associated capital and operational costs.

Summary of Strategy & Benefits

The selected strategy focuses on installing a rooftop PV system sized to offset 110% of the facility's annual energy consumption. This approach achieves the following benefits:

- **Resilience:** Self-generation capacity reduces the reliance on utility service provider
- **Economic Savings:** Reduces annual utility costs by ~42%, from about $24,182 to $14,090
- **Financial Feasibility:** Delivers a simple payback of approximately 8 years, after which the station continues to accrue savings for the remaining system life
- **Environmental Impact:** Offsets approximately 17 metric tons of CO_2 emissions annually, directly contributing to local and regional climate goals
- **Technical Simplicity:** Requires only a minor breaker adjustment to comply with NEC 705.12 busbar requirements, avoiding major infrastructure upgrades
- **Operational Practicality:** Provides long-term stability in operating expenses without introducing unnecessary complexity in operations or maintenance

Next Steps

To advance the project, the following steps are recommended:

1. **Detailed Design & Site Assessment:** Conduct a 30% design phase evaluation, including structural assessment of the roof, electrical interconnection details, and shading analysis
2. **Vendor Quotations:** Obtain updated vendor quotes for PV system equipment, installation, and interconnection to refine cost estimates beyond NLR benchmarks
3. **Permitting & Interconnection:** Coordinate with Southern California Edison (SCE) to complete the interconnection study and ensure compliance with NEM 3 tariff rules
4. **Finalize Incentive Applications:** Submit applications for the 30% ITC (direct pay) to secure federal funding and reduce upfront capital cost
5. **Procurement & Installation:** Issue RFPs for procurement and construction, selecting qualified contractors with experience in municipal PV installations
6. **Commissioning & Monitoring:** Upon installation, perform commissioning tests, integrate the system with monitoring platforms, and establish an operations and maintenance (O&M) plan to ensure reliable long-term performance

Appendix

Incentive Programs

This section outlines how the incentive programs function and provides relevant information about them. Specific application of these programs to presented scenarios is explored in previous sections.

Inflation Reduction Act

The Inflation Reduction Act of 2022 stands as a significant piece of legislation designed to strengthen the United States' commitment to fighting climate change by making considerable investments in renewable energy. A key feature of the Inflation Reduction Act is its financial incentives, namely the Investment Tax Credit (ITC) and the Production Tax Credit (PTC), which aim to accelerate the adoption of renewable energy technologies.

The ITC allows for a significant tax credit for investments in renewable energy technologies, including solar panels and wind turbines, directly reducing the upfront cost of these systems. This makes renewable projects more financially viable and attractive to investors and consumers alike. On the other hand, the PTC provides a per-kilowatt-hour tax relief for the production of energy from renewable sources, incentivizing the operation and expansion of renewable energy facilities.

Notably, Inflation Reduction Act programs have been subject to change in recent legislation. Presented here are active opportunities as of the time of the report.

Production Tax Credit

The Production Tax Credit (PTC) within the framework of the Inflation Reduction Act offers considerable financial incentives for renewable energy projects, primarily designed to decrease the federal income tax liability based on the electricity produced per kilowatt-hour.

The PTC directly reduces the federal income tax for taxable entities. Furthermore, for non-taxable entities such as local governments, educational institutions, or nonprofit organizations, the PTC allows these credits to be monetized, facilitating their involvement in renewable energy initiatives. This provision is applicable for projects that become operational between January 1, 2023, and December 31, 2032, providing a broad window for planning and implementation.

Projects located in designated low-income energy communities receive further incentives. The PTC is structured to be claimable annually for a decade from the start date of operations of the qualifying renewable system, providing long-term financial support. This current structure of the PTC is set to continue through the end of 2024. Starting from January 1, 2025, the credit system will transition to a technology-neutral format, broadening the scope to include a wider array of technologies and fostering a more inclusive approach to renewable energy incentives.

As of the date of this report, the program is still active but solar projects must have “begun construction” by July 4, 2026.

The City project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

Investment Tax Credit

The Investment Tax Credit (ITC) established under the Inflation Reduction Act offers a powerful incentive for deploying renewable energy technologies by providing a reduction in federal tax liability. This reduction is calculated as a percentage of the capital investment made in eligible energy systems. Taxpayers can apply the ITC to their federal income tax for the year the technology is installed, significantly decreasing their tax burden.

Starting January 1, 2023, special provisions enable tax-exempt entities such as local governments and nonprofits to receive direct payments equivalent to the value of the credit. This arrangement improves the liquidity and financial feasibility of renewable projects for these organizations. The scope of eligible technologies under the ITC is broad, encompassing solar panels, wind turbines, fuel cells, and other renewable energy systems.

As of 2025, the Investment Tax Credit (ITC) for solar projects is set at 30% of the eligible costs, encompassing both the equipment and installation expenses. This rate is scheduled to decrease to 26% in 2033 and further to 22% in 2034. Systems rated under 1 megawatt (MW) qualify for the full 30% without having to comply with additional requirements; larger systems will only receive the full amount if they meet specific labor requirements. These include paying prevailing wages to workers during construction and using apprentices to perform a portion of the total construction hours (15% after 2023). Bonus credits are available based on site location, e.g. low-income communities.

The ITC is set to continue delivering these benefits at its current rate until 2032, contingent upon meeting the specific project criteria laid out in the act. Looking ahead, post-2024, the ITC will transition to a technology-neutral system, which will be applicable to all zero-emissions technologies, reflecting a shift towards a more inclusive and adaptable approach to supporting renewable energy development.

HHZP project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

As of the date of this report, the program is still active but critical deadlines for project eligibility and complete operability are quickly approaching in 2026 and 2027, respectively.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) offers financial incentives to non-residential customers of utility Company to encourage the adoption of energy storage systems. These systems help businesses prepare for power outages that may occur due to weather, emergencies, or other unforeseen events. The SGIP funding is authorized through 2024, with incentives structured to decrease over time as funding milestones are reached or as more participants enter the program.

Non-residential customers have access to three types of SGIP rebates: General Market, Equity, and Equity Resilience. Furthermore, SGIP incentives are significantly higher for vulnerable or disadvantaged communities through the Equity and Equity Resilience categories.

Incentives are typically paid upfront for residential systems upon project completion and site verification, while nonresidential systems may receive half upfront with the balance paid based on the system's performance over time. Eligibility for SGIP incentives extends to residential, commercial, industrial, agricultural, and municipal customers of specific utilities including Pacific Gas & Electric, Southern California Edison, SoCalGas, San Diego Gas & Electric, and those managed by the Center for Sustainable Energy.

To be eligible for this rebate, a facility must satisfy two conditions: firstly, it must fall under the category of a government agency, educational institution, non-profit organization, or small business. Secondly, it must fulfill at least one of the following requirements: be located in a Disadvantaged Community (DAC), be situated in a census tract where the Median Household Income of the Statewide Median Income or be situated in California Indian Country.

On the other hand, the equity resilience rebate offers a rate, covering a percentage of the cost of an average energy storage system. To qualify for this rebate, a facility must meet certain requirements. Firstly, it must have experienced two or more utility Public Safety Power Shut-offs (PSPS), or it should be located in a Tier 2 or 3 High Fire Threat District (HFTD) and serve customers in DACs or Low Income Communities. Secondly, it must fulfill at least one of the following additional criteria:

- Be a police station, fire station, emergency response provider, emergency operations center, 911 call center, medical facility, private and public natural gas, electric, water, wastewater, or flood facility, jail or prison, utility-designated PSPS assistance center, cooling center, homeless shelter.
- Be a grocery store, supermarket, or corner store with less than $15 million in annual gross receipts.

- Be an Independent Living Center or a Food Bank.

Modeling Assumptions

The modeling conducted for this feasibility study was based on standard industry benchmarks, available site data, and conservative assumptions to ensure realistic projections. The following key assumptions were applied:

1. **Energy Consumption Baseline** – Historical hourly load data (8,760 points) from the facility was consolidated to represent a typical annual profile. This served as the reference for sizing PV and BESS systems.
2. **PV System Costs** – Capital expenditure (CAPEX) and operations and maintenance (OPEX) values were derived from the National Laboratory of the Rockies (NLR) 2024–2025 benchmarks for commercial rooftop systems. PV CAPEX was assumed at $1.75–$2.00/Wdc, with OPEX at ~$19/kW-year.
3. **BESS Costs** – Battery energy storage CAPEX was modeled using NLR 2025 benchmarks at ~$350/kWh. OPEX was assumed at ~$40/kW-year, covering maintenance, monitoring, and lifecycle management.
4. **ITC Incentives** – A 30% Investment Tax Credit (direct pay) was assumed, reducing upfront project cost. No additional low-income or disadvantaged community adders were included, since the site does not qualify.
5. **Performance Parameters** –
    - PV generation modeled with HelioScope using site tilt, azimuth, and shading factors.
    - Battery modeled with 90% round-trip efficiency and daily cycling where applicable.
    - Energy inflation rate of 3% annually applied to utility costs.
6. **Utility Tariff** – The analysis used the most recent Southern California Edison tariff, **TOU-GS-2 Option D**, as published in the file *ELECTRIC_SCHEDULES_TOU-GS-2_2025*. It was assumed under the current **NEM 3** framework. Exported PV energy was valued at ~25% of retail rate. Since tariff structures and prices are subject to future changes, the financial outcomes presented here should be viewed as indicative estimates rather than fixed projections.
7. **Infrastructure** – Electrical interconnection feasibility was preliminarily evaluated using customer-provided single-line diagrams. Minor breaker adjustment (600 A to 500 A) was assumed to comply with NEC 705.12 120% busbar rule for PV backfeed.
8. **Environmental Impact** – Greenhouse gas (GHG) reduction estimates were calculated using EPA eGRID emission factors for the CAMX subregion, applied to modeled PV generation.

Disclaimer: These figures are rough estimates intended for feasibility-level evaluation. If more precise values are required, additional detail must be developed through site-specific engineering, vendor quotations, and utility coordination during the advanced design phase.

Net Energy Metering

Net Energy Metering (NEM) in California is a billing arrangement that allows residential and commercial customers who generate their own electricity, primarily through solar photovoltaic (PV) systems, to receive credit for the surplus energy they contribute to the grid. This system is designed to incentivize the use of renewable energy sources by offsetting the cost of electricity consumption with the energy produced by these installations.

Under NEM, when a solar system generates more electricity than is consumed, the excess energy is sent back to the utility grid, and the customer earns credits. These credits can then be used to offset the cost of energy drawn from the grid when the solar system isn't producing enough to meet the customer's demand, like during nighttime or cloudy days. The rules, rates, and credits under NEM can vary over time, with different iterations such as NEM 1, 2, and the latest NEM 3, each having specific regulations and compensation structures for solar energy production and exchange.

The transition from NEM 2 to NEM 3 in California, which was effective on April 14, 2023, introduced significant changes in the net metering policies for utility customers with photovoltaic (PV) systems. These changes impact

several aspects, particularly the economics of energy arbitrage between PV system owners and the utility. Here's a summary of the key changes:

1) **Reduction in Export Rates:** Under NEM 3, there's a substantial reduction in the rates for excess electricity exported onto the grid by solar systems. This rate has been reduced by approximately 75%, thereby lowering the overall savings for home solar systems and increasing the payback period. This change is a shift from the traditional one-to-one offset of net metering policies, where the price of a kWh of electricity pushed onto the grid was equal to the price of a kWh pulled off the grid.
2) **Implementation of Electrification Rates:** Customers enrolling in NEM 3 are required to use electrification rates instead of regular Time-of-Use (TOU) rates. These electrification rates feature higher on-peak charges and lower off-peak charges, along with a fixed charge of $15 per month. The peak rate period remains from 4 pm to 9 pm.
3) **Export Compensation Based on Avoided Cost Calculator (ACC):** Export compensation under NEM 3 is determined by California's ACC, with specific export rates for every combination of Month, Hour, and Weekday or Weekend. The export value is lowest in the middle of the day when solar energy is abundant on the grid and highest during peak summer demand periods. Notably, the export rates are significantly lower than retail rates during the hours when PV systems are most productive (10 am – 3 pm). To maintain the financial viability of solar PV systems, customers in PG&E and SCE service territories receive an adder on top of the ACC rate, ranging between 2.2 and 9 cents depending on location and customer class.
4) **Shift to a Cost Avoidance System:** NEM 3 introduces a cost avoidance system for exported electricity. This system pays customers the lowest amount a company can pay under the Public Utility Regulatory Policies Act of 1978 (PURPA), which is significantly less than the typical retail rate. This results in customers receiving, on average, 75% less for the electricity they sell back to the grid, with rates varying by month and by hour.
5) **Grandfathering NEM 2 under NEM 3:** Under the recent NEM 3 policy in California, existing customers with a photovoltaic (PV) system installed under NEM 2 can retain the benefits and terms of their NEM 2 agreement, a process known as "grandfathering." However, these customers are restricted from replacing or adding capacity to their PV systems if they wish to maintain their NEM 2 status, as any significant modifications would require transitioning to the terms of NEM 3.

The Net Energy Metering (NEM) 3.0 policy introduces transformative changes, particularly enhancing the value of utilizing Battery Energy Storage Systems (BESS) for owners of solar power systems. A significant aspect of NEM 3.0 is the reduction in compensation rates for surplus electricity fed back into the grid by solar systems, now down to 75%. This adjustment shifts the financial dynamics, making it less lucrative to export excess solar energy to the grid. Instead, storing this surplus energy in a BESS and utilizing it when energy costs are higher becomes a more financially savvy approach.

The utility of BESS extends beyond merely optimizing the use of solar energy. It offers several additional advantages, such as providing backup power during utility blackouts, mitigating charges associated with demand peaks, and enabling energy arbitrage. Energy arbitrage under this system allows for the charging of BESS not only with excess solar energy but also with cheaper grid energy during low-cost periods. This stored energy can then be used in lieu of more expensive grid power at peak times, effectively reducing reliance on utility-supplied energy. Consequently, NEM 3.0 not only promotes more efficient use of solar energy but also broadens the scope of BESS applications, contributing to a more versatile and resilient energy management strategy.

AECOM

Microgrid Feasibility Study
City of Jurupa Valley

Site:
Jurupa Valley Operations Center
5293 Mission Blvd, Jurupa Valley, CA 92509

February 2026

Delivering a better world

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Executive Summary

This study appraises the viability and benefits of distributed energy resource implementation scenarios at the subject site. Four scenarios were developed and compared, key metrics summarized below:

Case	Components	CAPEX ($)	Annual Utility Bill ($/year)	Annual Savings ($/year)	Payback Period (years)	GHG Reduction ($MT CO_2e$/year)
1	PV	~78,000 (46,800 w/ ITC)	~13,363	~6,463	~8	~38
2	PV + BESS	~46,800 (ITC + SGIP)	~3,735	~16,091	~4	~38
3	BESS	~45,000	~19,826	Minimal	No ROI	None
0	Business as usual (no addition)	0	~19,826	0	N/A	None

- **Case 1: Photovoltaic (PV) array** – Introduces newly sized onsite energy generation capability.
- **Case 2: New PV array + battery energy storage system (BESS)** – Enables energy storage, increased self-consumption, and enhanced resilience capability.
- **Case 3**: **BESS** – Provides resilience support and could help cover potential shortfalls between the existing generator capacity and the site's critical demand; however, it is partially redundant given the presence of an onsite backup generator and offers limited economic justification as a standalone solution..
- **Case 0**: Maintains full utility dependence with no additional resilience benefits.

Regarding Cases 1 and 2, it is acknowledged that there is already an existing PV array onsite that offsets approximately 30% of the center's energy consumption. The PV array depicted in Cases 1 and 2 comprises an expanded system sized to account for the entirety of the site's current demand profile. This approach, rationale, and implementation considerations (e.g., NEM 3.0) are detailed in subsequent sections.

Considering the above, detailed more in subsequent sections, this study concludes that the **Case 2** (PV + BESS) scenario is the most suitable and cost-effective path forward, striking a balance between resilience capabilities, technical feasibility, and financial performance.

Recommended Next Steps

1. Advance to a 30% design phase with detailed site and structural assessments
2. Procure vendor-specific quotations to refine cost estimates beyond what is provided in this study
3. Initiate permitting and interconnection applications with Southern California Edison under the current Net Energy Metering tariff (NEM 3.0)
4. Secure federal incentives, specifically the 30% Investment Tax Credit (direct pay), to lower upfront costs
5. Prepare procurement and construction planning, targeting installation within the next budget cycle.

The goal is that with these data-driven microgrid feasibility assessment findings, the City of Jurupa Valley can make an informed decision regarding an appropriate resilience-improving investment at the subject site.

Background

Purpose

In recent years, especially within the past decade, the impacts of extreme heat and wildfires have been profound through the Inland Empire. Power service disruptions have been increasing in frequency and severity throughout Riverside County, affecting the availability of essential services and community resources.

In 2023, the Western Riverside Council of Governments (WRCOG) received an award (Grant Agreement OPR23145) from the Adaptation Planning Grant Program of the California Governor's Office of Land Use & Climate Innovation Integrated Climate Adaptation and Resilience Program. This program provides funding to help fill local, regional, and tribal planning needs, provides communities the resources to identify climate resilience priorities, and supports the development of a pipeline of climate-resilient infrastructure projects across the state.

As part of this grant-funded project, the Energy Resilience Plan 2.0, WRCOG commissioned microgrid feasibility studies for its member agencies. These studies serve to provide valuation of a potential microgrid at a community-essential facility, as designated by the member agency.

The site selected for the City of Jurupa Valley is Operations Center located at **5293 Mission Blvd, Jurupa Valley, CA 92509**.

This study presents key insights and findings from the evaluation of distributed energy resource (DER) scenarios, including photovoltaic (PV) array and battery energy storage system (BESS) components, at the subject site. It includes analysis of the site's historic energy demand profile and appraises potential PV array and BESS sizing and siting scenarios accordingly. Notably, the study includes assessment of the generation and storage requirements to support the site's critical loads to enable resilience for a specified number of hours during power service disruptions.

Furthermore, this study outlines the financial implications of self-generation, including estimated cost savings, return on investment (ROI), and potential financing options for the project.

It is important to note that this study serves as a preliminary technical and financial assessment. Its purpose is to provide the City of Jurupa Valley with the information to make an informed decision on whether to proceed to next phases of microgrid implementation before committing to detailed engineering design and further investment.

Adaptation Planning Grant Program

As communities in California experience more frequent, prolonged, and severe impacts from climate change, communities and governments at all scales are developing strategies and implementing actions to build a climate-resilient future. However, many jurisdictions, especially under-resourced communities in California, lack the capacity, tools, guidance, and resources to effectively prepare for climate impacts.

The Adaptation Planning Grant Program addresses this capacity gap by providing funding to help fill planning needs, providing communities with the resources to identify climate resilience priorities, and supporting the development of climate resilience projects across the state. The Adaptation Planning Grant Program enables communities to climate risk and adaptation considerations into planning activities and prepare for climate readiness and resilience in the long term.

The Adaptation Planning Grant is part of the Integrated Climate Adaptation and Resilience Program (ICARP) housed within the Governor's Office of Land Use and Climate Innovation. ICARP advances statewide climate adaptation and resilience by coordinating investments, partnerships, and climate science to ensure people, natural systems, and the built environment are protected, prepared, and thrive in the face of climate change.

Through direct and equity-focused investments and resources, ICARP helps build climate adapted and equitable communities in California, with a focus on solutions that address the impacts of climate change and reduce greenhouse gas emissions. ICARP works to advance these priorities across all levels of government by developing

actionable science and research; providing guidance, tools, and technical assistance; and administering climate resilience-focused grant programs.

Learn more: https://lci.ca.gov/climate/icarp/

Modeling Methodology

This section defines the criteria for sizing the PV array and BESS system components, detailing general parameters, technical requirements, and expected performance criteria.

PV Modeling

1. **Data Inputs**
    - **Solar Resource**: Hourly or sub-hourly irradiance data (e.g., typical meteorological year or on-site measurements)
    - **Site-Specific Factors**: Tilt angle, azimuth, shading analysis, and available roof/ground space
2. **Simulation Approach**
    - Use of HelioScope software to estimate hourly PV production
3. **Sizing Criteria**
    - **Capacity Target**: The sizing criteria are based on 110% of the facility's current annual energy consumption. This approach aims to fully offset the facility's energy usage with the PV array while incorporating an additional 10% capacity to accommodate future demand growth. However, the final system capacity is constrained by the area designated as available by the client.
    - **Performance Ratio**: Evaluate Performance Ratio to ensure consistent system output
    - **Energy Production**: Hourly, daily, monthly, and annual PV generation forecasts
    - **Load Matching**: Amount of PV energy that directly offsets site load vs. excess exported to the grid

BESS Modeling

1. **Data Inputs**
    - **Load Profile**: Detailed electricity consumption and demand patterns
    - **PV Production Profile**: From the PV modeling results
    - **Energy Duration for Resilience**: Determine the critical loads that the BESS will support during islanding operations
2. **Operational Modes**
    - **Energy Shifting / Excess PV Storage**: Battery charges when PV output exceeds site demand, discharges when site demand is high.
    - **Resilience (Standalone BESS)**: Sized to support critical loads during outages
3. **Sizing Criteria**
    - **Capacity (kWh)**: Based on required autonomy (energy shifting, peak shaving, or resilience duration)
    - **Max Discharge/Charge Rate (kW)**: Aligned with site load peaks, PV generation surpluses, and emergency power needs
4. **Simulation Approach**
    - Hourly or sub-hourly dispatch modeling to maximize economic benefit (e.g., demand charge reductions or avoided peak rates)

- Incorporate battery round-trip efficiency, self-discharge, and operational constraints (e.g., partial charge strategies)

5. **Output**

   - **Discharge/Charge Profiles**: Hourly modeling of how the battery is utilized
   - **Cost Savings**: Reduction in energy and demand charges or avoided grid cost
   - **Backup Duration**: If sized for resilience, the total hours/days of critical load coverage

Assumptions

AECOM collected facility data through a request for information process. Energy consumption factors and facility characteristics were identified and integrated in analysis. AECOM used these combined datasets to confirm energy utility consumption baselines.

In performing the analysis, AECOM made the following assumptions:

- This report refers to the site Operations Center, located 5293 Mission Blvd, Jurupa Valley, CA 92509.
- The monthly and annual electricity consumption is determined using load profile data in the client-provided file "NEW_JURUPA VALLEY, CITY OF_ Interval Data_8011354373_Ticket 385879." This file contains 35,040 load profile data points, which are then consolidated into an 8760 load profile dataset.
- AECOM utilized the Levelized Cost of Energy (LCOE) for the installed cost per watt of PV installations and BESS, as sourced from the National Labratory of the Rockies (NLR). This data was used to estimate the hypothetical cost of installing the PV array and BESS at the site, as detailed in this report. For an accurate cost estimation, it is necessary to obtain vendor quotes, which are subject to change due to market-dependent time windows. These quotations are typically conducted during the 60% design phase, at which point there is an understanding of the specific equipment ratings and brands to be used.
- This report evaluates the site's existing electrical infrastructure using customer-provided data on the main breaker and bus capacity, as documented in the client-provided file " JVOC Plans_JV5906_2005 SEP - RUBIDOUX FLEET BLDG BASE BLDG - NPN - 016-5-01." AECOM has assessed whether the existing electrical system can support the proposed PV array and BESS installation. However, as this is a feasibility study, an on-site assessment is required for a definitive determination. A site visit should be conducted during the advanced design phase, typically at the 30% design stage, to confirm site-specific conditions.
- AECOM has estimated the potential PV generation capacity based on the client-identified available area. However, a site assessment is required in later project phases, typically at the 30% design stage, to ensure that the site has the necessary infrastructure for PV array installation. This includes evaluating civil structures, load-bearing capacity, particularly for rooftop installations, and other critical conditions necessary for successful implementation.
- This report uses a regionalized estimate of general production (kWh) to calculate the amount of greenhouse gas emissions avoided through PV generation. The calculation is based on the U.S. EPA Emissions & Generation Resource Integrated Database (eGRID).
- This report clarifies that other charges such as connection fees, required service charges, and taxes remain unchanged. The analysis focuses solely on the bill components directly affected by the installation of PV and BESS under the NEM 3 framework.
- Energy exported to the utility is valued at approximately one quarter of the applicable retail electricity rate for the purposes of this analysis under NEM factors.

AECOM utilized the following tools in conducting the analysis:

- AECOM Internal Tools: Proprietary tools developed by AECOM for analyzing energy patterns and evaluating system performance in simulated environments. These tools are designed to assess energy costs for applications such as peak shaving, energy trading, etc. in DER implementations.
- HelioScope: Web-based software tool used for the design and performance analysis of photovoltaic systems. It combines system layout design with energy simulation, allowing users to model rooftop, ground-mounted, and canopy PV installations. The software factors in module placement, tilt, azimuth, shading, and local weather data to provide accurate estimates of system capacity and expected energy generation.

Site Information

In terms of electrical infrastructure, the site is equipped with a main switchboard identified as “DS1” rated 120/208 volts (V), 3-phase, 4-wire, with a 1600 ampere (A) bus and a 1200 A main circuit breaker, with 42 kilo-ampere interrupting capacity (kAIC) symmetrical minimum interrupting rating. The switchboard is fed from the utility (SCE) transformer and distributes multiple 3-pole feeders to lighting and power panelboards (LA, LB, LC, LD, LE), mechanical air handling units (MAU-1 through MAU-4), and air conditioning loads (AC-1 through AC-4).

The load summary indicates a total connected load of 365.52 kilovolt-ampere (kVA) at 120/208 V, 3-phase, 4-wire. Feeder construction shown is copper, with the largest feeders using up to two parallel sets of 4 conductors #4/0 AWG (with voltage drop calculations shown up to approximately 3.00% on the longest runs).

For standby power distribution, an automatic transfer switch (ATS) is shown rated 208/120 V, 3-phase, 100 A, supplying selected emergency/standby distribution (including an IT room panel/feeders labeled from the ATS). A generator is shown rated 50 kVA, 208/120 V, 3-phase, connected to serve the ATS loads.



Figure 1. Site Location

There is an existing PV array onsite (1.2 kW) that offsets approximately 30% of the center’s energy consumption. Notably, this array is interconnected under the Net Energy Metering (NEM) 1.0 tariff, which enables bill credits for excess electricity sent back to the grid, offsetting costs, and annual settlement for any surplus.

However, it is understood that this equipment is aged and its current performance capability (i.e., loss factor) relative to a new system is unknown. For this reason, and given that this feasibility study has been commissioned to evaluate the hypothetical resilience capacity of the site, this existing PV array is neglected in this analysis in favor of a new system. Details are available in the Case 1 and 2 scenarios below.

Incentive Programs

AECOM has identified three key incentive programs that could benefit the subject site, focusing on renewable energy production and advanced energy storage systems.

The Investment Tax Credit (ITC) and Production Tax Credit (PTC) are federal incentives that reduce the cost of renewable energy projects. ITC offers a tax credit based on a percentage of upfront investment costs, while PTC provides a per-kilowatt-hour credit for electricity generated over time.

Production Tax Credit

Under this initiative, the project is eligible for a tax credit ranging from 0.3 cents to 1.5 cents per installed kWh. The specific value of the credit is determined by several factors, including the project's adherence to certain requirements such as complying with labor standards and using domestic materials.

The PTC program pays for each kilowatt-hour produced over a 10-year period, with government entities receiving the benefit as direct pay instead of a tax credit. For this project, with an estimated 69,194 kWh per year, the best case at 1.5 ¢/kWh would yield about $1,037 annually, totaling around $10,370 over 10 years.

Investment Tax Credit

The City may utilize either the ITC or the PTC, but not both. Because the project has not yet begun construction, the ITC remains the preferred alternative. In this scenario, the project is assumed to be located within a qualifying low-income census tract, enabling eligibility for the additional 10 percent bonus credit.

Under the Low-Income Communities Bonus Credit Program, projects located within a designated low-income community, as defined by the 2016–2020 census tract boundaries in Figure 3, receive an additional 10 percentage points added to the base ITC. This increases the total credit from 30 percent to 40 percent of the eligible project cost.

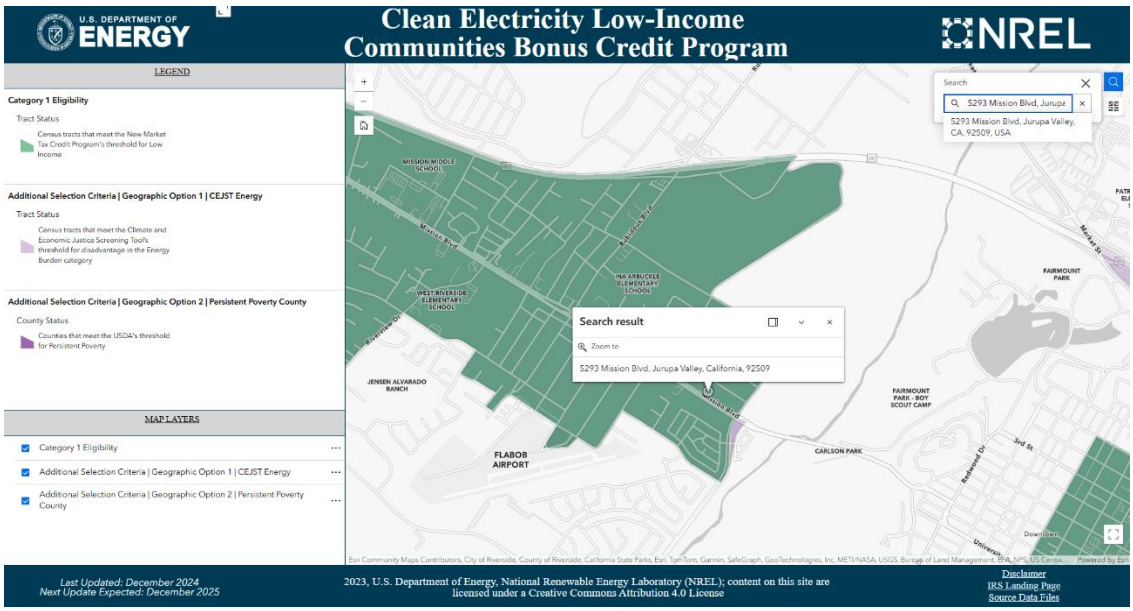


Figure 2. Clean Electricity Low-Income Communities Bonus Credit Program Map

Using NLR's CAPEX range of $1.75–2.00/W DC, the proposed 39 kW DC PV system would cost between $68,250 and $78,000. With a 40 percent ITC, the resulting direct-pay benefit increases to $27,300-31,200, reducing the project's upfront capital requirements accordingly.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) is California's primary incentive designed to reduce the upfront cost of energy storage systems. The program has three levels:

- **General Market**: For projects located outside Disadvantaged Communities (DAC). Typical incentive: $0.10/Wh.
- **Equity (DAC):** For projects located within a DAC. Incentive: $0.85/Wh.
- **Equity Resilience:** For critical facilities within a DAC and in PSPS or high fire-risk zones. Incentive: $1.00/Wh.

In Case 2, the project is located within a DAC, so it qualifies for the Equity level. Using an NLR-based cost of $450 /kWh, the 200-kWh battery would cost approximately $90,000. At the Equity incentive rate of $0.85/Wh, the available support would total $170,000, which is sufficient to fully cover the system cost within SGIP's allowable limits.

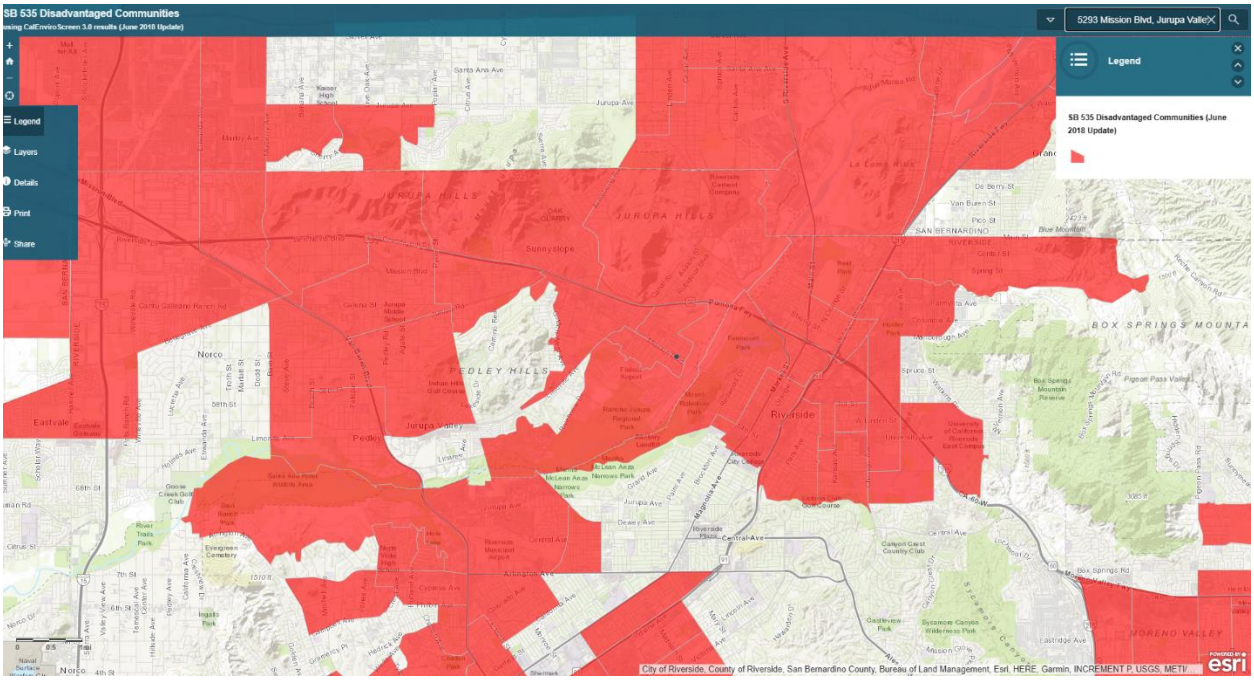


Figure 3. SB 535 Disadvantaged Communities Map

Scenarios & Analysis

Case 0: Current Situation (Baseline)

Tariff & Contract Type

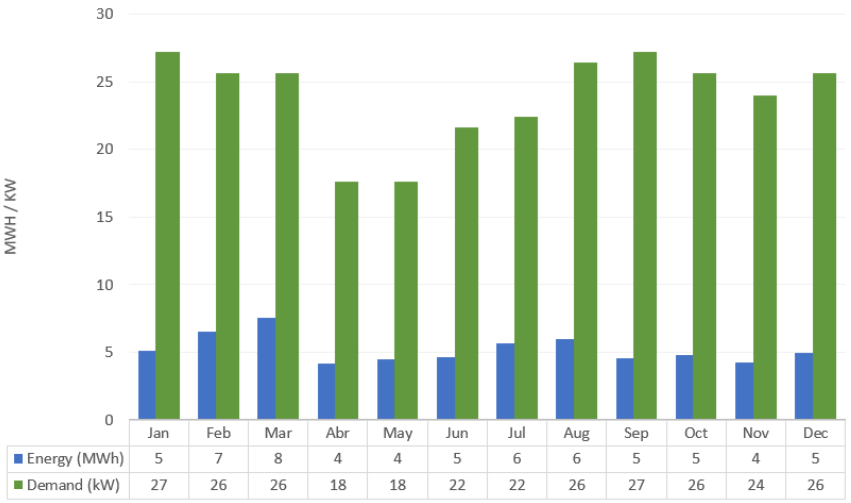
The site is currently served by Southern California Edison (SCE) under the TOU-GS-2-E tariff, which is designed for small to medium commercial customers. This rate structure separates costs into energy charges (based on kilowatt-hours consumed) and demand charges (based on the highest kilowatt demand registered during the billing cycle). In addition, prices vary by time-of-use periods—on-peak, mid-peak, and off-peak—so the timing of energy use significantly affects overall costs.

Being on this tariff means the site's operating expenses are directly tied not only to how much energy is consumed but also to when it is consumed and how high the peak demand reaches.

The tariff cost presents the costs as totals (delivery + bundle). The prices were used as the basis for this study. While they may fluctuate slightly month to month depending on market conditions, these variations are generally minor.

Monthly & Annual Energy Consumption and Demand

The facility currently consumes 62903 kWh annually, with March being the highest month at about 8 MWh and April the lowest at about 4 MWh. In terms of demand, January peak demand is experienced in January at about 27 kW, while May is the lowest at about 18 kW. The following graph presents this historical data for the 2024–2025 period.



	Jan	Feb	Mar	Abr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Energy (MWh)	5	7	8	4	4	5	6	6	5	5	4	5
Demand (kW)	27	26	26	18	18	22	22	26	27	26	24	26

Figure 4. Historic Site Energy Profile

Monthly & Annual Energy Costs

The site currently spends about $19,826 per year in energy and demand cost, with approximately $14,626 in energy costs and $4,894 in demand charges, based on tariff TOU-GS-2-E simulation. For this analysis, we are focusing only on energy and demand costs, as these are the components directly impacted by the installation of a PV system.

Case 1: PV Only

Modeled PV Production

The existing PV array onsite has been neglected in this Case 1 scenario in favor a newly modeled system for the following reasons:

- The existing PV system currently offsets roughly 30% of the site's energy consumption. However, the panels are old, and their actual performance and long-term loss-of-factor (LOF) relative to new panels is unknown. Accurately accounting for this would require a deeper technical assessment to properly adjust production estimates, pricing assumptions, ROI, and long-term annual energy yield.
- The maximum allowable increase in PV capacity on an existing NEM 1.0 system is approximately 1.2 kW in order to remain under NEM 1.0. Any increase beyond this threshold automatically triggers a transition to NEM 3.0.
- Given the site's current demand, a meaningful contribution would require PV capacity significantly in excess of 1.2 kW.
- Accordingly, this case study represents a modeled PV capacity sized to reflect the site's current energy profile. Notably, this analysis, therefore, assumes a transition to NEM 3.0 permitted operations.

This new modeled PV system for the site was sized to offset approximately 110% of current consumption, with the goal of fully offsetting present usage while reserving about 10% additional capacity for future growth. The placement areas for the PV installation were identified according to customer requirements. The system capacity is estimated at 39 kW direct current (DC), with an expected annual production of about 69,194 kWh.

Figure 6 presented the modeled energy production throughout the year, and Figure 7 identifies the designated PV installation areas on the site.

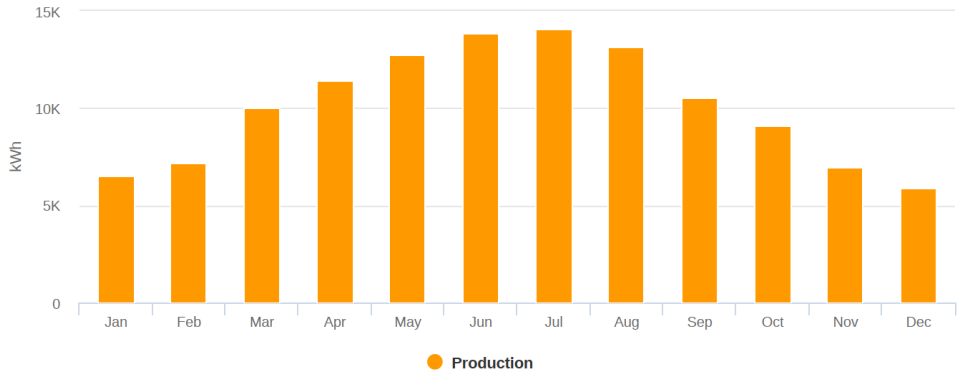


Figure 5. Modeled PV Production



Figure 6. Modeled PV Installation Areas

The modeled PV system is projected to generate an average of **5,739 kWh per month**, with an estimated **annual production of 69,194 kWh**.

This scenario doesn't include a BESS, so the excess energy produced need be exported to the utility, which requires entering a Net Energy Metering (NEM) contract with the utility service provider. Under the currently available NEM tariff, NEM 3.0, exported electricity is credited at dynamic rates that vary by month, hour of day, and weekday, ranging from as low as $0.01/kWh during midday hours to over $1.00/kWh during peak evening hours in high-demand months like August and September. This study has calculated projected benefits from this arrangement.

Figure 8 compares historic monthly energy consumption and modeled PV generation. Not all solar energy will be consumed on-site, as excess daytime production may exceed demand and be exported to the grid, while nighttime demand cannot be covered since there is no generation after sunset and no battery to store the excess in this scenario.

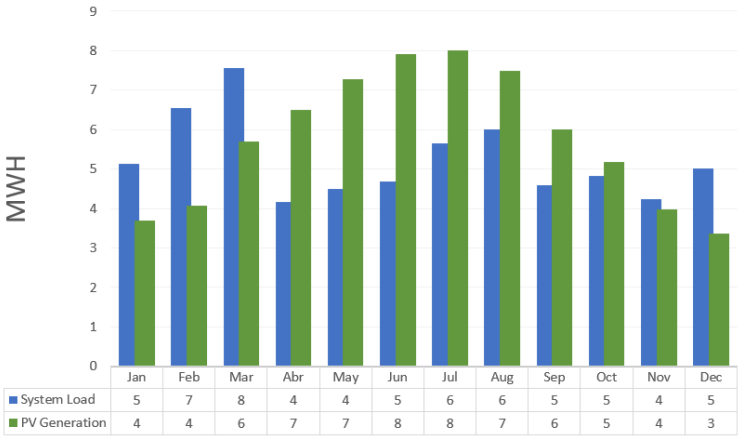


Figure 7. Modeled PV Output vs. Site Demand

Capital Expenditures

Based on NLR benchmark CAPEX values for commercial rooftop solar, the estimated cost to install a 39 kW DC PV system in Riverside County, California falls in the range of $1.75 to $2.00 per watt DC. This translates to a total investment of **approximately $78,000 for the complete system**.

These figures include typical equipment, installation, and soft costs, reflecting average market conditions for commercial-scale projects. Actual costs may vary slightly depending on site-specific conditions such as roof structure, permitting, interconnection requirements, and labor. However, the NLR benchmarks provide a reliable basis for estimating the capital cost of a system of this size and type in the region.

Operating Expenses

According to NLR's 2024 benchmark data, the annual operations and maintenance (OPEX) cost for commercial rooftop PV systems is about $19 per kW-DC. For a 39 kW DC system, this translates to an **estimated yearly OPEX of roughly $741** covering routine maintenance, monitoring, and related operational expenses.

Economic Metrics

The analysis shows that installing a PV system at the site under NEM3 provides measurable financial benefits by offsetting both energy and demand charges. Without solar, the facility currently spends about $19,826 annually on utility costs. With the PV system in operation, the energy cost is reduced to approximately $8,469 per year, while the demand cost drops to about $4,894 per year. In addition, the system generates excess electricity during the day that cannot be fully consumed on-site. Under NEM3 rules, this exported energy represents an additional benefit of roughly $3,013 annually.

Taken together, these reductions and export credits **reduce the facility's total utility bill down to $13,363 per year**, achieving an **overall savings of about 33%** compared to current expenses.

Payback Period and Return on Investment

The financial analysis shows that without PV, the facility spends approximately $19,826 per year on utility costs. With a 39 kW DC PV system installed, the annual cost is reduced to about $13,363, resulting in yearly savings of roughly $6,463. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system is estimated at $78,000, but with the 40 percent ITC direct pay, the net investment is reduced to approximately $46,800. In addition, the system carries an annual OPEX of $741, which slightly offsets the yearly savings. Taking these factors into account, the project generates a net benefit of about $6,463 minus $741 per year after OPEX. This results in a simple payback period of approximately 8 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross Savings ($)	Net Savings after OPEX ($)	Cumulative Cash Flow ($)
1	6,463	5,722	-41,078
2	6,657	5,893	-35,185
3	6,856	6,070	-29,115
4	7,062	6,252	-22,863
5	7,274	6,440	-16,423
6	7,492	6,633	-9,790
7	7,717	6,832	-2,958
8	7,948	7,037	4,079
9	8,187	7,248	11,327
10	8,432	7,466	18,793
15	9,775	8,655	59,617
20	11,332	10,033	106,944

Table 1. Return on Investment w/ 3% Inflation: Case 1

Technical Feasibility

According to the one-line diagram, the facility is served from an SCE utility transformer supplying switchboard DS1 at 120/208 V, three-phase, four-wire, which distributes power to multiple downstream panelboards and loads.

To interconnect an additional 39 kW DC PV system, the PV inverter output would be connected at switchboard DS1 through a dedicated three-pole backfed circuit breaker installed in an available breaker position. A visible and lockable AC PV disconnect would be installed between the inverter and DS1, adjacent to the service equipment, consistent with the existing distribution configuration.

The PV feeder conductors and equipment grounding conductor would be sized based on the PV inverter output and breaker rating shown at DS1. The PV system grounding and bonding would be tied directly into the existing service grounding electrode system at the switchboard.

The PV system would be interconnected only on the normal power distribution at DS1 and would not be connected to the emergency distribution served through the existing automatic transfer switch and generator.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 69,194 kWh per year. Using the U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:

- Carbon dioxide (CO_2): 79,300 pounds (lbs) (36.0 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 83,700 lbs (38.0 metric tons) avoided annually
- Nitrogen oxides (NOx): 59 lbs (26.8 kg) avoided annually
- Sulfur dioxide (SO_2): 1.5 lbs (0.7 kg) avoided annually

Case 2: PV + BESS

System Components

This scenario assumes the same PV array described in Case 1 and a BESS sized for surplus PV production. The day with the highest energy surplus in our simulation occurred on June 1, during which the PV system produced 287 kWh, the site consumed 108 kWh, and the resulting surplus was 178 kWh. To size the BESS, we ran several iterations based on the available surplus energy and applied an algorithm that simulates the charge and discharge cycles of one year. This techno-financial analysis indicates that the optimal BESS capacity is approximately 200 kWh.

This simulation factor ensures that even under variations in production or demand, all possible excess solar energy generated during the day can be stored. The stored energy is then available for use at night or during periods when PV production does not fully cover the site's demand.

By doing so, most of the units of solar energy produced on-site are consumed daily by the facility, preventing as little as possible any export to the grid. As a result, the utility bill for both energy and demand charges can effectively be reduced to zero, with only fixed or non-energy charges remaining.

Modeled Energy Flows

By installing a 200 kWh battery, we ensure that all the energy generated on-site is consumed by the facility itself. The charge and discharge profile of the battery is designed so that any PV surplus during the day is immediately stored in the battery rather than exported to the grid. Later, if the site demand exceeds the PV generation while there is still energy stored in the battery, the deficit is supplied from the battery.

This operational strategy minimizes or even eliminates consumption from the utility, since the PV and battery combination is prioritized to cover the load at all times. On an annual basis, the system is expected to produce slightly more energy than the site requires, leaving a surplus of around 10%, but this excess is negligible in terms of the overall utility bill.

Capital Expenditures

According to NLR benchmark data, the capital expenditure (CAPEX) for a commercial-scale 39 kW DC rooftop PV system in Riverside, California is **estimated at $46,800** under ITC incentive, based on installation costs of $1.75–2.00 per watt DC.

For storage, NLR's 2025 cost projections indicate a CAPEX of $450 per kWh for the high-cost scenario. Applying this benchmark to a commercial-scale 200 kWh battery system represents an investment of roughly $90,000 and under the SGIP program this amount can be fully covered, effectively funding 100% of the BESS system

Together, the combined CAPEX for the PV and BESS systems is estimated at $46,800 representing the expected upfront investment for a commercial solar-plus-storage project of this size.

Operating Expenses

According to NLR benchmark data, the annual operations and maintenance (OPEX) cost for a commercial-scale 39 kW DC rooftop PV system is estimated at $741.

NLR data indicates an operating cost of approximately $4 per kW-year. For a commercial-scale 200 kWh battery system, this results in an **annual OPEX of about $800**.

Together, the combined OPEX for the PV and BESS systems is approximately $1,541 per year, covering routine maintenance, monitoring, and system management.

Economic Metrics

The analysis shows that installing a commercial-scale PV system paired with a 200 kWh battery under NEM 3 provides strong financial advantages by allowing a substantial portion of the solar energy produced by the PV system to be consumed on-site. In several cases, PV production exceeds the facility's demand, and the surplus can be stored in the BESS for later use. However, without a battery system, the facility cannot absorb all of this excess energy, since any unused generation must be consumed the moment it is produced. This unused energy would otherwise need to be exported to the utility grid, where under current NEM rules it would be compensated at only about 25 percent of the retail electricity rate. Given that time-of-use pricing makes stored energy far more valuable during high-cost periods, it becomes financially preferable to store surplus solar rather than sell it.

Without a BESS, exporting this excess would generate $3,013 but the facility would still face an annual utility cost of 13,363 By contrast, installing the BESS reduces grid reliance and allows the facility to consume nearly all of its solar production during higher-priced periods, resulting in a significantly lower annual utility bill of $3,735.

To remain conservative, this analysis assumes that 10% of annual energy costs remain due to efficiency losses, imperfect alignment of PV output and site load, and seasonal variability.

It is important to note that other charges—such as connection fees, requisite charges, and taxes—remain unaffected. This analysis focuses only on those bill components directly impacted by the installation of PV and BESS under the NEM 3 framework.

Payback Period and Return on Investment

The financial analysis shows that without PV + BESS, the facility spends approximately $19,826 per year on utility costs. With a 39 kW DC PV system and 200 kWh BESS system installed, the annual cost is reduced to about $ 3,735 resulting in yearly savings of roughly $16,091. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system under ITC and SGIP incentives is estimated at $46,800. In addition, the system carries an annual OPEX of $ 1,541 Taking these factors into account, the combined system generates a net benefit of about 14,550 per year after OPEX. This results in a simple payback period of approximately 4 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross-Savings ($)	Net-Savings after OPEX ($)	Cumulative Cash Flow ($)
1	16,090	14,549	-32,251
2	16,573	14,986	-17,265
3	17,070	15,435	-1,830
4	17,582	15,898	14,069
5	18,110	16,375	30,444
6	18,653	16,867	47,310
7	19,213	17,373	64,683
8	19,789	17,894	82,577
9	20,383	18,431	101,007
10	20,994	18,983	119,991
15	24,338	22,007	223,800
20	28,214	25,512	344,143

Table 2. Return on Investment w/ 3% Inflation: Case 2

Technical Feasibility

The existing electrical system is fed from a utility transformer (shown as “SCE transformer”) into a 120/208 V, 3 phase, 4 wire switchboard labeled “DS1” with a 1600 A bus and a 1600 A main breaker.

To interconnect the proposed PV (39 kW DC) and the proposed BESS (200 kWh), provide dedicated interconnection points at the DS1 switchboard with new PV and BESS breakers installed in available breaker spaces, or add/modify the DS1 distribution section if the required breaker frame sizes exceed the available spaces shown on the one line.

If the PV and BESS are connected on the load side as backfed sources at DS1, maintain NEC 705.12 bus loading compliance at the DS1 bus. With a 1600 A bus and a 1600 A main, the combined PV breaker rating plus BESS breaker rating must be 320 A or less (1.2 × 1600 A minus 1600 A) for a load side backfeed interconnection at DS1.

Do not land the PV or BESS on downstream small feeders serving specific loads (for example the 100 A feeder that serves the automatic transfer switch) because those feeders are shown as limited to their breaker ratings

Perform a protection and coordination review at DS1 for the added source contributions, including available fault current, breaker interrupting ratings, and selective coordination impacts on the existing DS1 feeder breakers (225 A, 400 A, 150 A, 100 A, and multiple 50 A branch feeders as shown).

Provide required utility visible disconnecting means and equipment labeling at the PV and BESS points of interconnection and update the one line and load summary to reflect the new PV and BESS breakers and their connection location at DS1.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 69,194 kWh per year. Using the U.S. EPA’s Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:

- Carbon dioxide (CO_2): 29,643 lbs (13.45 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 29,753 lbs (13.50 metric tons) avoided annually
- Nitrogen oxides (NOx): 22.97 lbs (10.42 kg) avoided annually
- Sulfur dioxide (SO_2): 1.38 lbs (0.63 kg) avoided annually

CASE 3: BESS Only

Critical Load Identification

Based on the one-line electrical drawings for the Operator Center, the facility functions as an operations and control building. Under NEC 700, NEC 701, NFPA 110, and NFPA 72, the systems that require emergency or legally required standby power are limited to life-safety egress lighting, fire alarm and notification circuits, essential communications and dispatch equipment, security and access control necessary for safe operation, and any code-required standby systems serving the operations floor. No process or general convenience loads are required by code to be classified as emergency.

Using these criteria, the critical load is reasonably limited to approximately 25 percent of the total connected load, resulting in a calculated critical demand of 82 kW.

Required Backup Duration

For the site, maintaining continuous operation of alarm systems, emergency communications, lighting, and fuel dispensing is essential to guarantee mission readiness. According to NFPA 110 (Section 4.2 and 7.12.1), emergency power supply systems (EPSS) must provide a minimum of 2 hours of operation at full rated load. However, because fire stations are classified as critical public safety facilities, most Authorities Having Jurisdiction (AHJs) and best practice guidelines require at least 4 hours of backup capacity to ensure firefighters can respond to emergencies during extended outages.

Battery Capacity & Infrastructure

The BESS capacity is derived directly from the critical demand and required duration. With a critical load of 82 kW and a required duration of 4 hours, the resulting emergency energy requirement is 328 kWh, with a corresponding power rating of 82.0 kW.

Integration of a BESS at this scale would require connection on the emergency or legally required standby distribution section visible in the one-line diagrams, downstream of the normal source but ahead of emergency branch circuits. An automatic transfer scheme separating normal and emergency loads is required, along with verification of bus capacity, breaker ratings, and available space for a dedicated BESS feeder and disconnecting means.

Capital Expenditures

Using cost benchmarks published by the National Laboratory of the Rockies (NLR), the estimated **capital cost** (CAPEX) for 100 kWh / 20 kW battery energy storage system is approximately $**45,000**. This figure includes the battery cabinets, inverter/PCS, microgrid controller with ATS, installation, protections, and engineering.

Operating Expenses

The expected **operating cost** (OPEX) is about **$400 per year**, also based on NLR reference values. This covers preventive maintenance, monitoring software, and NFPA 110 testing requirements. Battery replacement is typically required after 10–12 years of service.

Return on Investment & Qualitative Benefits

While a conventional financial return ROI cannot be directly applied to this case, the value of a BESS for a fire station is usually framed in terms of resilience, reliability, and compliance. Such systems are designed to ensure uninterrupted operation of life-safety and mission-critical equipment, including fire alarms, communications, lighting, and fuel dispensing, during extended utility outages. The benefits include maintaining service continuity, safeguarding firefighter readiness, and protecting the surrounding community. Compliance with NFPA 110, NFPA 70, and NFPA 72 also reduces liability exposure and ensures that the facility meets recognized safety standards.

However, for this particular site, the installation of a battery energy storage system does not present a compelling case. The facility already operates with a 50 kW emergency generator, which is deficient to sustain the identified critical load of approximately 80 kW, However, a more detailed evaluation is required to accurately determine the critical load. Given this existing capacity, the addition of a 100 kWh / 20 kW BESS as a resilience measure would

provide the cover for the kW difference benefit relative to cost. The generator fully covers the resilience requirement, and, therefore, the justification for a BESS here may be contestable.

Technical Considerations

Key technical considerations include confirming available bus capacity for an additional emergency source, compliance with the 120 percent load-side interconnection rule where applicable, adequacy of existing breakers and feeders, and clear separation of normal and emergency circuits through the transfer equipment. Final design will require short-circuit and coordination studies, validation of transfer sequences between utility, generator, and BESS sources, and confirmation of UL 9540A compliance for the selected battery system within the electrical configuration shown on the one-line diagrams.

Decision Matrix and Scenario Comparison

In order to determine the most appropriate scenario for the site, four scenarios were developed and analyzed: business as usual (Case 0), installing a PV system only (Case 1), installing PV with a BESS (Case 2), and installing a BESS only (Case 3). Each case was evaluated in terms of resilience value, capital and operating expenditures, energy savings, payback period, and technical feasibility. The decision matrix summarizes the comparative performance of these options.

Criteria	Case 0: Baseline	Case 1: PV Only	Case 2: PV + BESS	Case 3: BESS Only
Resilience Benefit	None	Limited (daytime only)	Moderate (self-consumption, some coverage)	High (but redundant due to existing 55 kW generator) Critical Load 82kW
CAPEX ($)	0	$27k – $31k	$27 – $31k	~$65k
OPEX ($/yr)	Current	~$741	~$1,540	~$400
Annual Utility Bill ($)	~$19,826	~$13,363	~$3,7354	~$19,826 (no reduction)
Annual Savings ($)	–	~$6,463	~$16,090	Minimal (non-financial)
Payback Period	–	~8 years	~6 years	No ROI
GHG Reduction	None	~38 $MTCO_2e$ avoided annually	Same as Case 1	None
Technical Feasibility	Already in place	Requires PV breaker and interconnection at DS1	Requires PV and BESS breakers, controls, and coordination review	Technically feasible pair with existing backup Gen

Table 3. Scenario Comparison

Conclusion

Based on the comparative analysis, **Case 2 (PV + BESS)** is the recommended scenario for the site. While the facility currently operates with a 50 kVA backup generator, this capacity may be insufficient relative to the site's critical load based on a preliminary review of the electrical system, though a more detailed study is required to confirm this. The PV + BESS configuration enhances resilience by supplementing the existing generator and reserving battery capacity to support critical loads during outages, improving continuity of operations without requiring immediate generator replacement. From a financial perspective, this case also offers the strongest economic justification, as federal ITC incentives for PV and SGIP Equity incentives for storage can effectively cover most or all of the battery capital cost, while increasing PV self-consumption, minimizing NEM 3 exports, and materially improving annual utility savings.

Summary of Strategy & Benefits

The selected strategy focuses on deploying a PV system paired with a BESS sized to maximize on site solar utilization while reserving a portion of battery capacity for resilience support. This approach delivers the following benefits:

- **Resilience**: The combined PV and BESS system enhances backup capability by supplementing the existing 50 kVA generator and supporting critical loads that exceed generator capacity during outages.
- **Economic Savings**: Maximizes annual utility savings by increasing self consumption of PV generation and reducing reliance on exported energy under NEM 3 tariff structures.
- **Financial Feasibility**: SGIP incentives can fully offset the battery capital cost, while ITC incentives significantly reduce PV investment, resulting in a strong overall return.
- **Operational Flexibility**: Allows battery dispatch to be dynamically allocated between bill optimization and resilience, depending on operating conditions and outage scenarios.
- **Environmental Impact**: Achieves substantial greenhouse gas emissions reductions through increased on site renewable energy utilization.
- **Scalable Design**: Provides a platform that can be expanded or reconfigured in the future if critical load definitions or resilience requirements change.

Next Steps

To advance the project, the following steps are recommended:

1. **Detailed Design & Site Assessment:** Conduct a 30% design phase evaluation, including structural assessment of the roof, electrical interconnection details, and shading analysis
2. **Vendor Quotations:** Obtain updated vendor quotes for PV system equipment, installation, and interconnection to refine cost estimates beyond NLR benchmarks
3. **Permitting & Interconnection:** Coordinate with Southern California Edison (SCE) to complete the interconnection study and ensure compliance with NEM 3 tariff rules
4. **Finalize Incentive Applications:** Submit applications for the 30% ITC (direct pay) to secure federal funding and reduce upfront capital cost
5. **Procurement & Installation:** Issue RFPs for procurement and construction, selecting qualified contractors with experience in municipal PV installations
6. **Commissioning & Monitoring:** Upon installation, perform commissioning tests, integrate the system with monitoring platforms, and establish an operations and maintenance (O&M) plan to ensure reliable long-term performance

Appendix

Incentive Programs

This section outlines how the incentive programs function and provides relevant information about them. Specific application of these programs to presented scenarios is explored in previous sections.

Inflation Reduction Act

The Inflation Reduction Act of 2022 stands as a significant piece of legislation designed to strengthen the United States' commitment to fighting climate change by making considerable investments in renewable energy. A key feature of the Inflation Reduction Act is its financial incentives, namely the Investment Tax Credit (ITC) and the Production Tax Credit (PTC), which aim to accelerate the adoption of renewable energy technologies.

The ITC allows for a significant tax credit for investments in renewable energy technologies, including solar panels and wind turbines, directly reducing the upfront cost of these systems. This makes renewable projects more financially viable and attractive to investors and consumers alike. On the other hand, the PTC provides a per-kilowatt-hour tax relief for the production of energy from renewable sources, incentivizing the operation and expansion of renewable energy facilities.

Notably, under more recent legislation, systems must be fully installed and placed in service by December 31, 2025 to qualify for these benefits.

Production Tax Credit

The Production Tax Credit (PTC) within the framework of the Inflation Reduction Act offers considerable financial incentives for renewable energy projects, primarily designed to decrease the federal income tax liability based on the electricity produced per kilowatt-hour.

The PTC directly reduces the federal income tax for taxable entities. Furthermore, for non-taxable entities such as local governments, educational institutions, or nonprofit organizations, the PTC allows these credits to be monetized, facilitating their involvement in renewable energy initiatives. This provision is applicable for projects that become operational between January 1, 2023, and December 31, 2032, providing a broad window for planning and implementation.

Projects located in designated low-income energy communities receive further incentives. The PTC is structured to be claimable annually for a decade from the start date of operations of the qualifying renewable system, providing long-term financial support. This current structure of the PTC is set to continue through the end of 2024. Starting from January 1, 2025, the credit system will transition to a technology-neutral format, broadening the scope to include a wider array of technologies and fostering a more inclusive approach to renewable energy incentives.

As of the date of this report, the program is still active but solar projects must have “begun construction” by July 4, 2026.

The City project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

Investment Tax Credit

The Investment Tax Credit (ITC) established under the Inflation Reduction Act offers a powerful incentive for deploying renewable energy technologies by providing a reduction in federal tax liability. This reduction is calculated as a percentage of the capital investment made in eligible energy systems. Taxpayers can apply the ITC to their federal income tax for the year the technology is installed, significantly decreasing their tax burden.

Starting January 1, 2023, special provisions enable tax-exempt entities such as local governments and nonprofits to receive direct payments equivalent to the value of the credit. This arrangement improves the liquidity and financial feasibility of renewable projects for these organizations. The scope of eligible technologies under the ITC is broad, encompassing solar panels, wind turbines, fuel cells, and other renewable energy systems.

As of 2025, the Investment Tax Credit (ITC) for solar projects is set at 30% of the eligible costs, encompassing both the equipment and installation expenses. This rate is scheduled to decrease to 26% in 2033 and further to 22% in 2034. Systems rated under 1 megawatt (MW) qualify for the full 30% without having to comply with additional requirements; larger systems will only receive the full amount if they meet specific labor requirements. These include paying prevailing wages to workers during construction and using apprentices to perform a portion of the total construction hours (15% after 2023). Bonus credits are available based on site location, e.g. low-income communities.

The ITC is set to continue delivering these benefits at its current rate until 2032, contingent upon meeting the specific project criteria laid out in the act. Looking ahead, post-2024, the ITC will transition to a technology-neutral system, which will be applicable to all zero-emissions technologies, reflecting a shift towards a more inclusive and adaptable approach to supporting renewable energy development.

HHZP project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

As of the date of this report, the program is still active but critical deadlines for project eligibility and complete operability are quickly approaching in 2026 and 2027, respectively.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) offers financial incentives to non-residential customers of utility Company to encourage the adoption of energy storage systems. These systems help businesses prepare for power outages that may occur due to weather, emergencies, or other unforeseen events. The SGIP funding is authorized through 2024, with incentives structured to decrease over time as funding milestones are reached or as more participants enter the program.

Non-residential customers have access to three types of SGIP rebates: General Market, Equity, and Equity Resilience. Furthermore, SGIP incentives are significantly higher for vulnerable or disadvantaged communities through the Equity and Equity Resilience categories.

Incentives are typically paid upfront for residential systems upon project completion and site verification, while nonresidential systems may receive half upfront with the balance paid based on the system's performance over time. Eligibility for SGIP incentives extends to residential, commercial, industrial, agricultural, and municipal customers of specific utilities including Pacific Gas & Electric, Southern California Edison, SoCalGas, San Diego Gas & Electric, and those managed by the Center for Sustainable Energy.

To be eligible for this rebate, a facility must satisfy two conditions: firstly, it must fall under the category of a government agency, educational institution, non-profit organization, or small business. Secondly, it must fulfill at least one of the following requirements: be located in a Disadvantaged Community (DAC), be situated in a census tract where the Median Household Income of the Statewide Median Income or be situated in California Indian Country.

On the other hand, the equity resilience rebate offers a rate, covering a percentage of the cost of an average energy storage system. To qualify for this rebate, a facility must meet certain requirements. Firstly, it must have experienced two or more utility Public Safety Power Shut-offs (PSPS), or it should be located in a Tier 2 or 3 High Fire Threat District (HFTD) and serve customers in DACs or Low Income Communities. Secondly, it must fulfill at least one of the following additional criteria:

- Be a police station, fire station, emergency response provider, emergency operations center, 911 call center, medical facility, private and public natural gas, electric, water, wastewater, or flood facility, jail or prison, utility-designated PSPS assistance center, cooling center, homeless shelter.
- Be a grocery store, supermarket, or corner store with less than $15 million in annual gross receipts.

- Be an Independent Living Center or a Food Bank.

Modeling Assumptions

The modeling conducted for this feasibility study was based on standard industry benchmarks, available site data, and conservative assumptions to ensure realistic projections. The following key assumptions were applied:

1. **Energy Consumption Baseline** – Historical hourly load data (8,760 points) from the facility was consolidated to represent a typical annual profile. This served as the reference for sizing PV and BESS systems.
2. **PV System Costs** – Capital expenditure (CAPEX) and operations and maintenance (OPEX) values were derived from the National Labratory of the Rockies (NLR) 2024–2025 benchmarks for commercial rooftop systems. PV CAPEX was assumed at $1.75–$2.00/Wdc, with OPEX at ~$19/kW-year.
3. **BESS Costs** – Battery energy storage CAPEX was modeled using NLR 2025 benchmarks at ~$350/kWh. OPEX was assumed at ~$40/kW-year, covering maintenance, monitoring, and lifecycle management.
4. **ITC Incentives** – A 30% Investment Tax Credit (direct pay) was assumed, reducing upfront project cost. No additional low-income or disadvantaged community adders were included, since the site does not qualify.
5. **Performance Parameters** –
    - PV generation modeled with HelioScope using site tilt, azimuth, and shading factors.
    - Battery modeled with 90% round-trip efficiency and daily cycling where applicable.
    - Energy inflation rate of 3% annually applied to utility costs.
6. **Utility Tariff** – The analysis used the most recent Southern California Edison tariff, **TOU-GS-2 Option D**, as published in the file *ELECTRIC_SCHEDULES_TOU-GS-2_2025*. It was assumed under the current **NEM 3** framework. Exported PV energy was valued at ~25% of retail rate. Since tariff structures and prices are subject to future changes, the financial outcomes presented here should be viewed as indicative estimates rather than fixed projections.
7. **Infrastructure** – Electrical interconnection feasibility was preliminarily evaluated using customer-provided single-line diagrams. Minor breaker adjustment (600 A to 500 A) was assumed to comply with NEC 705.12 120% busbar rule for PV backfeed.
8. **Environmental Impact** – Greenhouse gas (GHG) reduction estimates were calculated using EPA eGRID emission factors for the CAMX subregion, applied to modeled PV generation.

Disclaimer: These figures are rough estimates intended for feasibility-level evaluation. If more precise values are required, additional detail must be developed through site-specific engineering, vendor quotations, and utility coordination during the advanced design phase.

Net Energy Metering

Net Energy Metering (NEM) in California is a billing arrangement that allows residential and commercial customers who generate their own electricity, primarily through solar photovoltaic (PV) systems, to receive credit for the surplus energy they contribute to the grid. This system is designed to incentivize the use of renewable energy sources by offsetting the cost of electricity consumption with the energy produced by these installations.

Under NEM, when a solar system generates more electricity than is consumed, the excess energy is sent back to the utility grid, and the customer earns credits. These credits can then be used to offset the cost of energy drawn from the grid when the solar system isn't producing enough to meet the customer's demand, like during nighttime or cloudy days. The rules, rates, and credits under NEM can vary over time, with different iterations such as NEM 1, 2, and the latest NEM 3, each having specific regulations and compensation structures for solar energy production and exchange.

The transition from NEM 2 to NEM 3 in California, which was effective on April 14, 2023, introduced significant changes in the net metering policies for utility customers with photovoltaic (PV) systems. These changes impact

several aspects, particularly the economics of energy arbitrage between PV system owners and the utility. Here's a summary of the key changes:

1) **Reduction in Export Rates:** Under NEM 3, there's a substantial reduction in the rates for excess electricity exported onto the grid by solar systems. This rate has been reduced by approximately 75%, thereby lowering the overall savings for home solar systems and increasing the payback period. This change is a shift from the traditional one-to-one offset of net metering policies, where the price of a kWh of electricity pushed onto the grid was equal to the price of a kWh pulled off the grid.
2) **Implementation of Electrification Rates:** Customers enrolling in NEM 3 are required to use electrification rates instead of regular Time-of-Use (TOU) rates. These electrification rates feature higher on-peak charges and lower off-peak charges, along with a fixed charge of $15 per month. The peak rate period remains from 4 pm to 9 pm.
3) **Export Compensation Based on Avoided Cost Calculator (ACC):** Export compensation under NEM 3 is determined by California's ACC, with specific export rates for every combination of Month, Hour, and Weekday or Weekend. The export value is lowest in the middle of the day when solar energy is abundant on the grid and highest during peak summer demand periods. Notably, the export rates are significantly lower than retail rates during the hours when PV systems are most productive (10 am – 3 pm). To maintain the financial viability of solar PV systems, customers in PG&E and SCE service territories receive an adder on top of the ACC rate, ranging between 2.2 and 9 cents depending on location and customer class.
4) **Shift to a Cost Avoidance System:** NEM 3 introduces a cost avoidance system for exported electricity. This system pays customers the lowest amount a company can pay under the Public Utility Regulatory Policies Act of 1978 (PURPA), which is significantly less than the typical retail rate. This results in customers receiving, on average, 75% less for the electricity they sell back to the grid, with rates varying by month and by hour.
5) **Grandfathering NEM 2 under NEM 3:** Under the recent NEM 3 policy in California, existing customers with a photovoltaic (PV) system installed under NEM 2 can retain the benefits and terms of their NEM 2 agreement, a process known as "grandfathering." However, these customers are restricted from replacing or adding capacity to their PV systems if they wish to maintain their NEM 2 status, as any significant modifications would require transitioning to the terms of NEM 3.

The Net Energy Metering (NEM) 3.0 policy introduces transformative changes, particularly enhancing the value of utilizing Battery Energy Storage Systems (BESS) for owners of solar power systems. A significant aspect of NEM 3.0 is the reduction in compensation rates for surplus electricity fed back into the grid by solar systems, now down to 75%. This adjustment shifts the financial dynamics, making it less lucrative to export excess solar energy to the grid. Instead, storing this surplus energy in a BESS and utilizing it when energy costs are higher becomes a more financially savvy approach.

The utility of BESS extends beyond merely optimizing the use of solar energy. It offers several additional advantages, such as providing backup power during utility blackouts, mitigating charges associated with demand peaks, and enabling energy arbitrage. Energy arbitrage under this system allows for the charging of BESS not only with excess solar energy but also with cheaper grid energy during low-cost periods. This stored energy can then be used in lieu of more expensive grid power at peak times, effectively reducing reliance on utility-supplied energy. Consequently, NEM 3.0 not only promotes more efficient use of solar energy but also broadens the scope of BESS applications, contributing to a more versatile and resilient energy management strategy.

AECOM



Microgrid Feasibility Study
City of Lake Elsinore

Site:
Lake Community Center
310 W Graham Ave, Lake Elsinore, CA 92530

February 2026

Delivering a better world

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Executive Summary

This study appraises the viability and benefits of distributed energy resource implementation scenarios at the subject site. Four scenarios were analyzed, and key metrics are summarized below:

Case	Components	CAPEX ($)	Utility Savings	Payback Period (years)	GHG Reduction ($MTCO_2e$/year)
1	PV	~$100k	~$10k/yr (≈42%)	~6	~17
2	PV + BESS	~$190k (gross) ~$65k (net w/ ITC + SGIP)	~$20k/yr (≈85–90%)	~4	~17
3	BESS	~$65k	Minimal	N/A	None
0	Business-as-usual	$0	$0	N/A	None

Note: All values are approximate and subject to final design and incentive approval.

- **Case 1: Photovoltaic (PV) array –** Introduces on-site generation and provides meaningful utility cost reductions with moderate resilience benefits limited to daytime operation.
- **Case 2: PV + battery energy storage system (BESS)** – Combines on-site generation with energy storage, enabling near-complete self-consumption of solar energy under NEM 3, significantly reducing grid reliance. The availability of SGIP incentives materially improves project economics by potentially covering up to 100% of the battery system cost, resulting in accelerated payback and enhanced operational flexibility.
- **Case 3: BESS only** – Provides resilience benefits but does not materially reduce annual utility costs and lacks a clear financial return when deployed without on-site generation.
- **Case 0: Business-as-usual** – Maintains full dependence on utility service with no improvement in resilience, cost stability, or emissions reduction.

Considering the comparative analysis presented in this study, **Case 2 (PV + BESS)** is identified as the recommended scenario. Although it carries a higher gross capital cost, state and federal incentives substantially offset this investment, allowing the combined system to achieve the shortest payback period while delivering the highest annual savings. In addition, SGIP funding creates an opportunity to incrementally increase battery capacity, potentially by approximately 50 kWh, which can be reserved for resilience without materially impacting project economics.

Recommended next steps include:

1. Advance to a 30% design phase to confirm electrical, structural, and space constraints.
2. Obtain vendor-specific quotations for PV and BESS equipment to refine cost and performance assumptions.
3. Initiate SGIP application and reservation processes to secure storage incentives.
4. Proceed with permitting and interconnection applications under the applicable Net Energy Metering (NEM 3) framework.
5. Develop a final construction and procurement plan aligned with the City’s budget cycle.

The intent of this assessment is to support a data-driven decision by demonstrating that a PV + BESS strategy offers the most favorable balance of economic performance, incentive optimization, emissions reduction, and resilience enhancement for the subject site under current regulatory and market conditions.

Background

Purpose

In recent years, especially within the past decade, the impacts of extreme heat and wildfires have been profound through the Inland Empire. Power service disruptions have been increasing in frequency and severity throughout Riverside County, affecting the availability of essential services and community resources.

In 2023, the Western Riverside Council of Governments (WRCOG) received an award (Grant Agreement OPR23145) from the Adaptation Planning Grant Program of the California Governor's Office of Land Use & Climate Innovation Integrated Climate Adaptation and Resilience Program. This program provides funding to help fill local, regional, and tribal planning needs, provides communities the resources to identify climate resilience priorities, and supports the development of a pipeline of climate-resilient infrastructure projects across the state.

As part of this grant-funded project, the Energy Resilience Plan 2.0, WRCOG commissioned microgrid feasibility studies for its member agencies. These studies serve to provide valuation of a potential microgrid at a community-essential facility, as designated by the member agency.

The site selected for the City of Lake Elsinore is the Lake Community Center located at 310 W Graham Ave, Lake Elsinore, CA 92530.

This study presents key insights and findings from the evaluation of distributed energy resource (DER) scenarios, including photovoltaic (PV) array and battery energy storage system (BESS) components, at the subject site. It includes analysis of the site's historic energy demand profile and appraises potential PV array and BESS sizing and siting scenarios accordingly. Notably, the study includes assessment of the generation and storage requirements to support the site's critical loads to enable resilience for a specified number of hours during power service disruptions.

Furthermore, this study outlines the financial implications of self-generation, including estimated cost savings, return on investment (ROI), and potential financing options for the project.

It is important to note that this study serves as a preliminary technical and financial assessment. Its purpose is to provide the City of Lake Elsinore with the information to make an informed decision on whether to proceed to next phases of microgrid implementation before committing to detailed engineering design and further investment.

Adaptation Planning Grant Program

As communities in California experience more frequent, prolonged, and severe impacts from climate change, communities and governments at all scales are developing strategies and implementing actions to build a climate-resilient future. However, many jurisdictions, especially under-resourced communities in California, lack the capacity, tools, guidance, and resources to effectively prepare for climate impacts.

The Adaptation Planning Grant Program addresses this capacity gap by providing funding to help fill planning needs, providing communities with the resources to identify climate resilience priorities, and supporting the development of climate resilience projects across the state. The Adaptation Planning Grant Program enables communities to climate risk and adaptation considerations into planning activities and prepare for climate readiness and resilience in the long term.

The Adaptation Planning Grant is part of the Integrated Climate Adaptation and Resiliency Program (ICARP) housed within the Governor's Office of Land Use and Climate Innovation. ICARP advances statewide climate adaptation and resilience by coordinating investments, partnerships, and climate science to ensure people, natural systems, and the built environment are protected, prepared, and thrive in the face of climate change.

Through direct and equity-focused investments and resources, ICARP helps build climate adapted and equitable communities in California, with a focus on solutions that address the impacts of climate change and reduce greenhouse gas emissions. ICARP works to advance these priorities across all levels of government by developing

actionable science and research; providing guidance, tools, and technical assistance; and administering climate resilience-focused grant programs.

Learn more: https://lci.ca.gov/climate/icarp/

Modeling Methodology

This section defines the criteria for sizing the PV array and BESS system components, detailing general parameters, technical requirements, and expected performance criteria.

PV Modeling

1. **Data Inputs**
    - **Solar Resource**: Hourly or sub-hourly irradiance data (e.g., typical meteorological year or on-site measurements)
    - **Site-Specific Factors**: Tilt angle, azimuth, shading analysis, and available roof/ground space
2. **Simulation Approach**
    - Use of HelioScope software to estimate hourly PV production
3. **Sizing Criteria**
    - **Capacity Target**: The sizing criteria are based on 115% of the facility's current annual energy consumption. This approach aims to fully offset the facility's energy usage with the PV array while incorporating an additional 15% capacity to accommodate future demand growth. However, the final system capacity is constrained by the area designated as available by the client.
    - **Performance Ratio**: Evaluate Performance Ratio to ensure consistent system output
    - **Energy Production**: Hourly, daily, monthly, and annual PV generation forecasts
    - **Load Matching**: Amount of PV energy that directly offsets site load vs. excess exported to the grid

BESS Modeling

1. **Data Inputs**
    - **Load Profile**: Detailed electricity consumption and demand patterns
    - **PV Production Profile**: From the PV modeling results
    - **Energy Duration for Resilience**: Determine the critical loads that the BESS will support during islanding operations
2. **Operational Modes**
    - **Energy Shifting / Excess PV Storage**: Battery charges when PV output exceeds site demand, discharges when site demand is high.
    - **Resilience (Standalone BESS)**: Sized to support critical loads during outages
3. **Sizing Criteria**
    - **Capacity (kWh)**: Based on required autonomy (energy shifting, peak shaving, or resilience duration)
    - **Max Discharge/Charge Rate (kW)**: Aligned with site load peaks, PV generation surpluses, and emergency power needs
4. **Simulation Approach**
    - Hourly or sub-hourly dispatch modeling to maximize economic benefit (e.g., demand charge reductions or avoided peak rates)

- Incorporate battery round-trip efficiency, self-discharge, and operational constraints (e.g., partial charge strategies)

5. **Output**

   - **Discharge/Charge Profiles**: Hourly modeling of how the battery is utilized
   - **Cost Savings**: Reduction in energy and demand charges or avoided grid cost
   - **Backup Duration**: If sized for resilience, the total hours/days of critical load coverage

Assumptions

AECOM collected facility data through a request for information process. Energy consumption factors and facility characteristics were identified and integrated in analysis. AECOM used these combined datasets to confirm energy utility consumption baselines.

In performing the analysis, AECOM made the following assumptions:

- This report refers to the lake Community Center, located at 310 W Graham Ave, Lake Elsinore, CA 92530.
    - The monthly and annual electricity consumption are determined using utility energy and demand data extracted from twelve months of utility billing records. This data is processed through an AECOM algorithmic tool to generate an 8,760-hour load profile, which approximates the facility's annual energy consumption and demand behavior.
    - AECOM utilized the Levelized Cost of Energy (LCOE) for the installed cost per watt of PV installations and BESS, as sourced from the National Laboratory of the Rockies (NLR). This data was used to estimate the hypothetical cost of installing the PV array and BESS at the site, as detailed in this report. For an accurate cost estimation, it is necessary to obtain vendor quotes, which are subject to change due to market-dependent time windows. These quotations are typically conducted during the 60% design phase, at which point there is an understanding of the specific equipment ratings and brands to be used.
    - This report evaluates the site's existing electrical infrastructure using customer-provided data on the main breaker and bus capacity, as documented in the client-provided file "Pic LCC EP." AECOM has assessed whether the existing electrical system can support the proposed PV array and BESS installation. However, as this is a feasibility study, an on-site assessment is required for a definitive determination. A site visit should be conducted during the advanced design phase, typically at the 30% design stage, to confirm site-specific conditions.
    - AECOM has estimated the potential PV generation capacity based on the client-identified available area, as documented in the client-provided file "*LCC Solar PV Areas."* However, a site assessment is required in later project phases, typically at the 30% design stage, to ensure that the site has the necessary infrastructure for PV array installation. This includes evaluating civil structures, load-bearing capacity, particularly for rooftop installations, and other critical conditions necessary for successful implementation.
    - This report uses a regionalized estimate of general production (kWh) to calculate the amount of greenhouse gas emissions avoided through PV generation. The calculation is based on the U.S. EPA Emissions & Generation Resource Integrated Database (eGRID).
    - This report clarifies that other charges such as connection fees, required service charges, and taxes remain unchanged. The analysis focuses solely on the bill components directly affected by the installation of PV and BESS under the NEM 3 framework.

    AECOM utilized the following tools in conducting the analysis:

    - AECOM Internal Tools: Proprietary tools developed by AECOM for analyzing energy patterns and evaluating system performance in simulated environments. These tools are designed to assess energy costs for applications such as peak shaving, energy trading, etc. in DER implementations.
    - HelioScope: Web-based software tool used for the design and performance analysis of photovoltaic systems. It combines system layout design with energy simulation, allowing users to model rooftop, ground-mounted, and canopy PV installations. The software factors in module placement, tilt, azimuth, shading, and local weather data to provide accurate estimates of system capacity and expected energy generation.

Site Information

This study is conducted for Lake Community Center, located at 310 W Graham Ave, Lake Elsinore, CA 92530. The site currently consumes about **81,644 kWh of electricity per year**,

The site is equipped with a Murray “Class CTL Load Center,” LP230 series (LP230PC / LP230PS / LP230ES family), suitable for use as service equipment. The panel is rated for a maximum main breaker of 200 amperes (A) at 240 volts (V) and has a short-circuit interrupting rating of 10,000 root mean square (RMS) symmetrical amperes (10 kAIC) at 240 V, when installed per manufacturer requirements.

The panel supports multiple three-phase configurations, including 240 V alternating current (AC) three-phase three-wire, 120/208 V-AC three-phase four-wire, and 120/240 V-AC three-phase four-wire delta systems, including a high-leg delta arrangement with Phase B at 208 V to ground. The load center accepts copper or aluminum conductors (CU/AL) with conductor sizes up to 300 (kilo-circular mil) kcmil for a 200 A service, per the terminal ratings shown on the nameplate.

Based on the available information, the installation consists of a 200 A, 240 V, three-phase distribution panel rated at 10 kAIC, supplying downstream branch circuits and feeders for site loads. Detailed upstream utility transformer information and downstream load schedules are not visible on the provided diagram and would be required for a fully quantified system description.

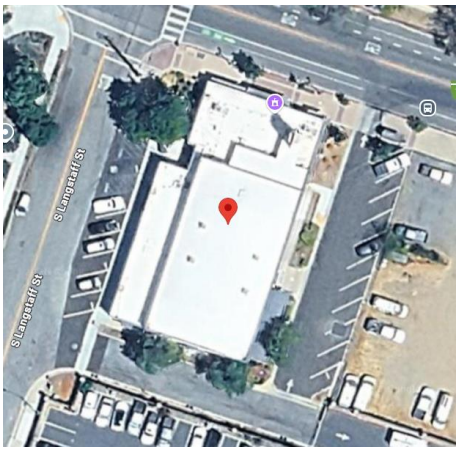


Figure 1. Site Location

The City indicated that PV was not viable on the west side of the building. WRCOG noted that PV arrays within the green boxes denoted in Figure 2 were to be assumed viable.



Figure 2. No-Go Areas for PV

Incentive Programs

AECOM has identified three key incentive programs that could benefit the subject site, focusing on renewable energy production and advanced energy storage systems.

The Investment Tax Credit (ITC) and Production Tax Credit (PTC) are federal incentives that reduce the cost of renewable energy projects. ITC offers a tax credit based on a percentage of upfront investment costs, while PTC provides a per-kilowatt-hour credit for electricity generated over time.

Production Tax Credit

Under this initiative, the project is eligible for a tax credit ranging from 0.3 cents to 1.5 cents per installed kWh. The specific value of the credit is determined by several factors, including the project's adherence to certain requirements such as complying with labor standards and using domestic materials.

The PTC program pays for each kilowatt-hour produced over a 10-year period, with government entities receiving the benefit as direct pay instead of a tax credit. For this project, with an estimated 94,960 kWh per year, the best case at 1.5 ¢/kWh would yield about $1,424 annually, totaling around $14,240 over 10 years.

Investment Tax Credit

The City may utilize either the ITC or the PTC, but not both. Because the project has not yet begun construction, the ITC remains the preferred alternative. In this scenario, the project is assumed to be located within a qualifying low-income census tract, enabling eligibility for the additional 10 percent bonus credit.

Under the Low-Income Communities Bonus Credit Program, projects located within a designated low-income community, as defined by the 2016–2020 census tract boundaries in Figure 3, receive an additional 10 percentage points added to the base ITC. This increases the total credit from 30 percent to 40 percent of the eligible project cost.

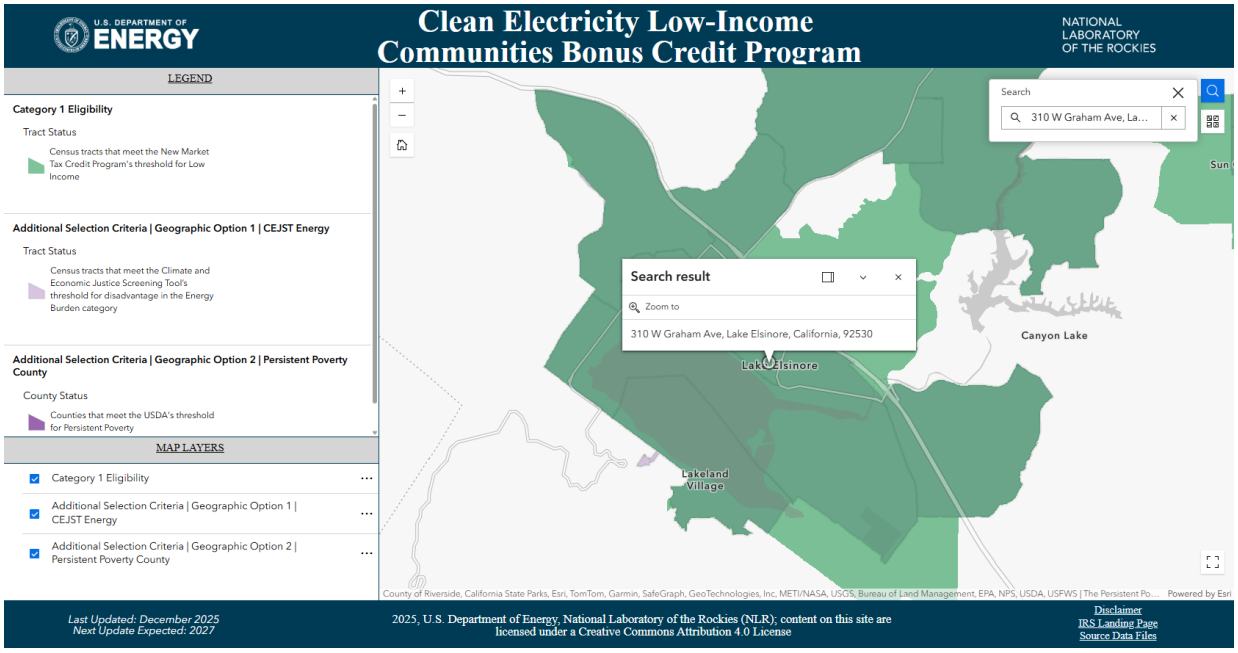


Figure 3. Clean Electricity Low-Income Communities Bonus Credit Program Map

Using NLR's CAPEX range of $1.75–2.00 / W direct current (DC), the proposed 54.5 kW-DC PV system would cost between $95,375 and 109,000. With a 40 percent ITC, the resulting direct-pay benefit increases to $38,150-43,600, reducing the project's upfront capital requirements accordingly.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) is California's primary incentive designed to reduce the upfront cost of energy storage systems. The program has three levels:

- **General Market:** For projects located outside Disadvantaged Communities (DAC). Typical incentive: $0.10/Wh.
- **Equity (DAC)**: For projects located within a DAC. Incentive: $0.85/Wh.
- **Equity Resilience**: For critical facilities within a DAC and in PSPS or high fire-risk zones. Incentive: $1.00/Wh.

In Case 2, the project is located within a SB 535 Disadvantaged Communities zone, so it qualifies for the Equity incentive rate. Using an NLR-based cost of $450/kWh, the 150-kWh battery would cost approximately $67,500. At the Equity incentive rate of $0.85/Wh, the available support would total $127,500, which is sufficient to fully cover the system cost within SGIP's allowable limits.

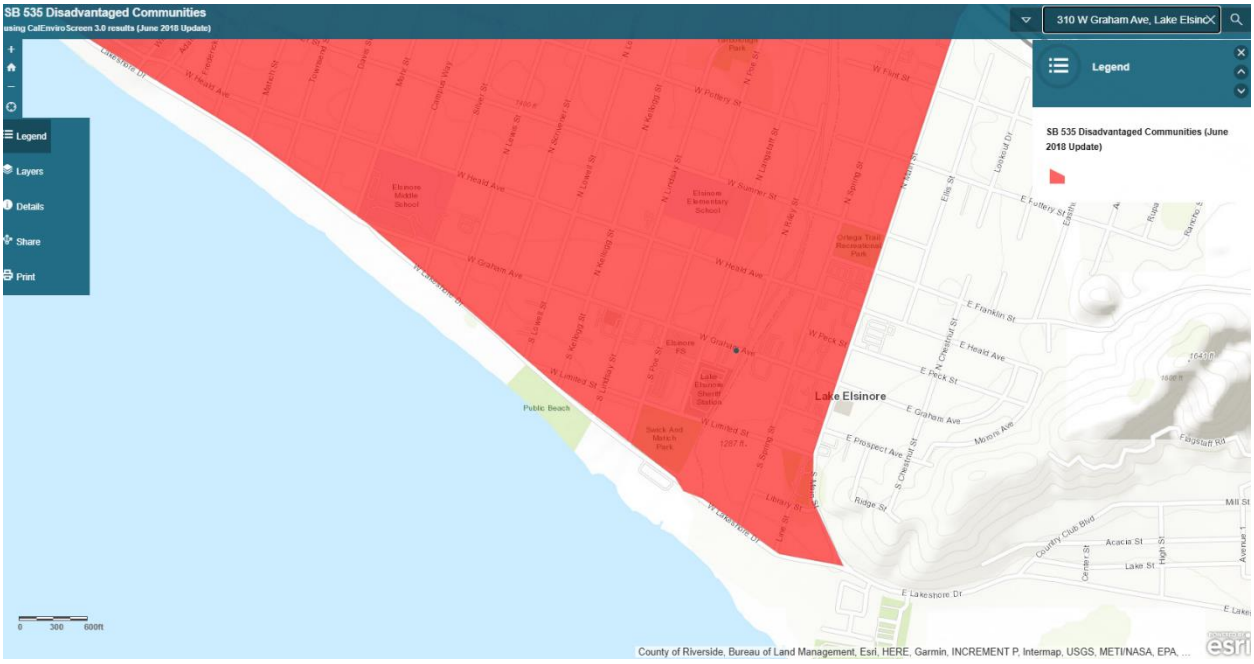


Figure 4. SB 535 Disadvantaged Communities Map

Scenarios & Analysis

Case 0: Current Situation (Baseline)

Tariff & Contract Type

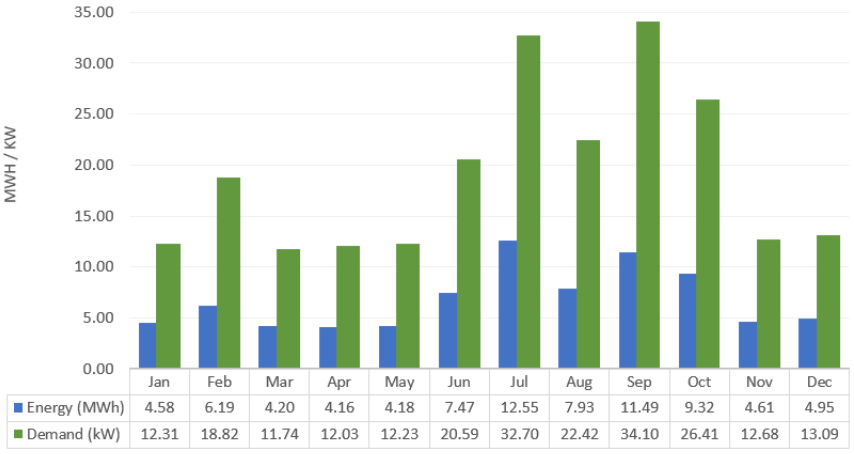
The site is currently served by Southern California Edison under the TOU-GS-2-E-APS-E tariff, which is designed for small to medium commercial customers. This rate structure separates costs into energy charges (based on kilowatt-hours consumed) and demand charges (based on the highest kilowatt demand registered during the billing cycle). In addition, prices vary by time-of-use periods—on-peak, mid-peak, and off-peak—so the timing of energy use significantly affects overall costs.

Being on this tariff means the site's operating expenses are directly tied not only to how much energy is consumed but also to when it is consumed and how high the peak demand reaches.

The tariff cost presents the costs as totals (delivery + bundle). The prices were used as the basis for this study. While they may fluctuate slightly month to month depending on market conditions, these variations are generally minor.

Monthly & Annual Energy Consumption and Demand

The facility currently consumes 81,644 kWh annually, with July being the highest month at about 12,550 kWh and April the lowest at about 4,160 kWh. In terms of demand, September records the peak at around 34 kW, while March is the lowest at about 11.7 kW. The following graph presents this historical data for the 2024–2025 period.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Energy (MWh)	4.58	6.19	4.20	4.16	4.18	7.47	12.55	7.93	11.49	9.32	4.61	4.95
Demand (kW)	12.31	18.82	11.74	12.03	12.23	20.59	32.70	22.42	34.10	26.41	12.68	13.09

Figure 5. Historic Site Energy Profile

Monthly & Annual Energy Costs

The site currently spends about $23,424 per year in energy and demand cost, with approximately $19,024 in energy costs and $4,400 in demand charges, based on tariff TOU-GS-2-E-ASP-E simulation. For this analysis, we are focusing only on energy and demand costs, as these are the components directly impacted by the installation of a PV system.

Case 1: PV Only

Installed Capacity & Location

The PV system for the site was sized to offset approximately 115% of current consumption, with the goal of fully offsetting present usage while reserving about 15% additional capacity for future growth. The placement areas for the PV installation were identified according to customer requirements. The system capacity is estimated at 54.5 kW direct current (DC), with an expected annual production of about 94,960 kWh.

Figure 6 presents the modeled energy production throughout the year, and Figure 7 identifies the designated PV installation areas on the site.

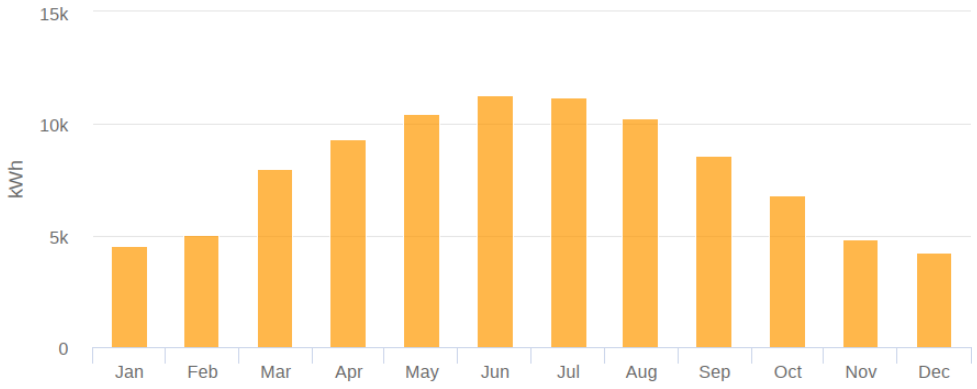


Figure 6. Modeled PV Production



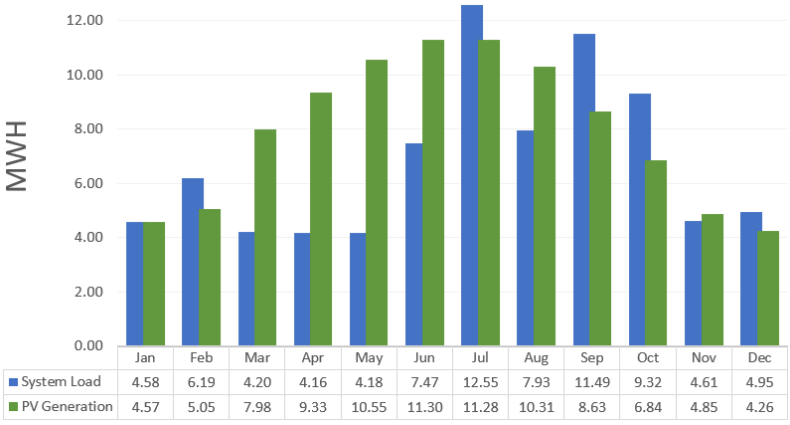
Figure 7. Modeled PV Installation Areas

Modeled PV Production

The modeled PV system is projected to generate an average of 7,913 kWh per month, with an estimated annual production of 94,960 kWh.

This scenario doesn't include a BESS, so the excess energy produced need be exported to the utility, which requires entering a Net Energy Metering (NEM) contract with the utility service provider. Under the currently available NEM tariff, NEM 3.0, exported electricity is credited at dynamic rates that vary by month, hour of day, and weekday, ranging from as low as $0.01/kWh during midday hours to over $1.00/kWh during peak evening hours in high-demand months like August and September. This study has calculated projected benefits from this arrangement.

Figure 8 compares historic monthly energy consumption and modeled PV generation. Not all solar energy will be consumed on-site, as excess daytime production may exceed demand and be exported to the grid, while nighttime demand cannot be covered since there is no generation after sunset and no battery to store the excess in this scenario.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
System Load	4.58	6.19	4.20	4.16	4.18	7.47	12.55	7.93	11.49	9.32	4.61	4.95
PV Generation	4.57	5.05	7.98	9.33	10.55	11.30	11.28	10.31	8.63	6.84	4.85	4.26

Figure 8. Modeled PV Output vs. Site Demand

Capital Expenditures

Based on NLR benchmark CAPEX values for commercial rooftop solar, the estimated cost to install a 54.5 kW DC PV system in Riverside County, California falls in the range of $1.75 to $2.00 per W-DC. This translates to a **total investment of approximately $57,246 – 65,424** for the complete system after ITC.

These figures include typical equipment, installation, and soft costs, reflecting average market conditions for commercial-scale projects. Actual costs may vary slightly depending on site-specific conditions such as roof structure, permitting, interconnection requirements, and labor. However, the NLR benchmarks provide a reliable basis for estimating the capital cost of a system of this size and type in the region.

Operating Expenses

According to NLR's 2024 benchmark data, the annual operations and maintenance (OPEX) cost for commercial rooftop PV systems is about $19 per kW-DC. For a 54.5 kW DC system, this translates to an **estimated yearly OPEX of roughly $1,036** covering routine maintenance, monitoring, and related operational expenses.

Economic Metrics

The analysis shows that installing a PV system at the site under NEM3 provides measurable financial benefits by offsetting both energy and demand charges. Without solar, the facility **currently spends about $23,424 annually** on utility costs. With the PV system in operation, the energy cost is reduced to approximately $11,110 per year, while the demand cost drops to about $3,402 per year. In addition, the system generates excess electricity during the day that cannot be fully consumed on-site. Under NEM3 rules, this exported energy represents an additional benefit of roughly $2,697 annually.

Taken together, these reductions and export credits **reduce the facility's total utility bill down to $11,815 per year**, achieving an overall savings of about 50% compared to current expenses.

Payback Period and Return on Investment

The financial analysis shows that without PV, the facility spends approximately $23,424 per year on utility costs. With a 54.5 kW DC PV system installed, the annual cost is reduced to about $11,815, resulting in yearly savings of roughly $11,609. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system is estimated at $109,040, but with the 40 percent ITC direct pay, the net investment is reduced to approximately $65,424. In addition, the system carries an annual OPEX of $1,036, which slightly offsets the yearly savings. Taking these factors into account, the project generates a net benefit of about $11,609 minus 1,036 per year after OPEX. This results in a simple payback period of approximately 6 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross Savings ($)	Net Savings after OPEX ($)	Cumulative Cash Flow ($)
1	11,609	10,573	-54,851
2	11,957	10,890	-43,961
3	12,316	11,217	-32,744
4	12,685	11,553	-21,191
5	13,066	11,900	-9,291
6	13,458	12,257	2,966
7	13,862	12,625	15,591
8	14,277	13,003	28,594
9	14,706	13,393	41,987
10	15,147	13,795	55,783
15	17,560	15,992	131,221
20	20,356	18,540	218,674

Table 1. Return on Investment w/ 3% Inflation: Case 1

Technical Feasibility

The service equipment is a 240 Vac load center with a 200 A main disconnect and a 200 A bus rating. The maximum allowable PV backfeed under NEC 705.12 (120% bus rule) is (1.20 × 200 A) − 200 A = 40 A, which limits the PV interconnection to a maximum 40 A backfed breaker at this equipment.

The PV inverter aggregate AC nameplate output is 50 kW-AC at 240 Vac, three-phase. The PV AC output current is 50,000 W ÷ (1.732 × 240 V) = 120.3 A. Applying the 125% continuous-current requirement, the required interconnection OCPD is 1.25 × 120.3 A = 150.4 A, which mandates a 175 A breaker as the next standard size.

The NEC 705 allowable backfeed at the existing bus is 40 A. The required PV backfeed (175 A) exceeds this limit by 135 A. Interconnection via a backfed breaker in this 200 A bus is noncompliant due to insufficient allowable backfeed capacity.

Corrective action shall be implemented using one of the following code-compliant methods: (1) install a supply-side connection per NEC 705.11 ahead of the 200 A service disconnect using a service-rated PV disconnect and OCPD sized to 175 A, (2) replace the existing service equipment with a minimum 400 A bus rating, providing allowable backfeed of (1.20 × 400 A) − 200 A = 280 A and supporting a 175 A PV breaker, or (3) install a dedicated service-rated PV interconnection section with a 400 A bus and land the 175 A PV breaker in that section while maintaining the existing 200 A service disconnect.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 94,960 kWh per year. Using the U.S. EPA Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:"

- Carbon dioxide (CO_2): 40,681 pounds (lbs) (18.45 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 40,833 lbs (18.52 metric tons) avoided annually
- Nitrogen oxides (NO_x): 31.527 lbs (14.30 kilograms) avoided annually
- Sulfur dioxide (SO_2): 1.899 lbs (0.86 kilograms) avoided annually

Case 2: PV + BESS

System Components

This scenario assumes the same PV array described in Case 1 and a BESS sized for surplus PV production. The day with the highest energy surplus in our simulation occurred on May 14, during which the PV system produced 402.26 kWh, the site consumed 132.88 kWh, and the resulting surplus was 269.38 kWh. For size the BESS, we ran several iterations based on the available surplus energy and applied an algorithm that simulates the charge and discharge cycles of one year. This techno-financial analysis indicates that the optimal BESS capacity is approximately 500 kWh.

This simulation factor ensures that even under variations in production or demand, all possible excess solar energy generated during the day can be stored. The stored energy is then available for use at night or during periods when PV production does not fully cover the site's demand.

By doing so, most of the units of solar energy produced on-site are consumed daily by the facility, preventing as little as possible any export to the grid.

Modeled Energy Flows

By installing a 150 kWh battery, we ensure that all the energy generated on-site is consumed by the facility itself. The charge and discharge profile of the battery is designed so that any PV surplus during the day is immediately stored in the battery rather than exported to the grid. Later, if the site demand exceeds the PV generation while there is still energy stored in the battery, the deficit is supplied from the battery.

This operational strategy minimizes or even eliminates consumption from the utility, since the PV and battery combination is prioritized to cover the load at all times. On an annual basis, the system is expected to produce slightly more energy than the site requires, leaving a surplus of around 10%, but this excess is negligible in terms of the overall utility bill.

Capital Expenditures

According to NLR benchmark data, the capital expenditure (CAPEX) for a commercial-scale 55.4 kW DC rooftop PV system in Riverside, California is estimated at $65,424 under ITC incentive, based on installation costs of $1.75–2.00 per watt DC.

For storage, NLR's 2025 cost projections indicate a CAPEX of $450 per kWh for the high-cost scenario. Applying this benchmark to a commercial-scale 150 kWh battery system represents an investment of roughly $67,500 under, and under the SGIP program this amount can be fully covered, effectively funding 100% of the BESS system

Together, the combined CAPEX for the PV and BESS systems is estimated at $65,424 representing the expected upfront investment for a commercial solar-plus-storage project of this size.

Operating Expenses

According to NLR benchmark data, the annual operations and maintenance (OPEX) cost for a commercial-scale 55.4 kW DC rooftop PV system is estimated at $1,036 USD.

NLR data indicates an operating cost of approximately $4 per kW-year. For a commercial-scale 150 kWh battery system, this results in an **annual OPEX of about $600**.

Together, the **combined OPEX for the PV and BESS systems is approximately $1,636 per year**, covering routine maintenance, monitoring, and system management.

Economic Metrics

The analysis shows that installing a commercial-scale PV system paired with a 150 kWh battery under NEM 3 provides strong financial advantages by allowing a substantial portion of the solar energy produced by the PV system to be consumed on-site.

In several cases, PV production exceeds the facility's demand, and the surplus can be stored in the BESS for later use. However, without a battery system, the facility cannot absorb all of this excess energy, since any unused generation must be consumed the moment it is produced. This unused energy would otherwise need to be exported

to the utility grid, where under current NEM rules it would be compensated at only about 25 percent of the retail electricity rate. Given that time-of-use pricing makes stored energy far more valuable during high-cost periods, it becomes financially preferable to store surplus solar rather than sell it.

Without a BESS, exporting this excess would generate $1,097 but the facility would still face an annual utility cost of $11,815 By contrast, installing the BESS reduces grid reliance and allows the facility to consume nearly all of its solar production during higher-priced periods, resulting in a significantly lower annual utility bill of $2,783

To remain conservative, this analysis assumes that 10% of annual energy costs remain due to efficiency losses, imperfect alignment of PV output and site load, and seasonal variability.

It is important to note that other charges—such as connection fees, requisite charges, and taxes—remain unaffected. This analysis focuses only on those bill components directly impacted by the installation of PV and BESS under the NEM 3 framework.

Payback Period and Return on Investment

The financial analysis shows that without PV + BESS, the facility spends approximately $23,424 per year on utility costs. With a 55.4 kW DC PV system and 150 kWh BESS system installed, the annual cost is reduced to about $2,783 resulting in yearly savings of roughly $20,641. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system under ITC and SGIP incentives is estimated at $65,424. In addition, the system carries an annual OPEX of $ 1,636 Taking these factors into account, the combined system generates a net benefit of about $19,605 per year after OPEX. This results in a simple payback period of approximately 4 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross-Savings ($)	Net-Savings after OPEX ($)	Cumulative Cash Flow ($)
1	20,641	19,005	-46,419
2	21,261	19,576	-26,843
3	21,898	20,163	-6,680
4	22,555	20,768	14,087
5	23,232	21,391	35,478
6	23,929	22,032	57,510
7	24,647	22,693	80,204
8	25,386	23,374	103,578
9	26,148	24,075	127,653
10	26,932	24,798	152,451
15	31,222	28,747	288,055
20	36,195	33,326	445,257

Table 2. Return on Investment w/ 3% Inflation: Case 2

Technical Feasibility

The existing electrical system shown is a Murray “Class CTL” load center that is suitable for use as service equipment, with a maximum main rating of 200 A and a 10,000 RMS symmetrical amp short-circuit rating at 240 V.

The panel is configured for 120/240 V-AC, 3-phase, 4-wire delta service (high-leg delta, with the phase-to-ground high leg noted as 208 V). This voltage system requires that any added inverter-based equipment be compatible with a 240 V delta source and that phase identification and landing points be carefully controlled to avoid misapplication on the high leg.

A 55.4 kW AC PV interconnection at 240 V, 3-phase corresponds to roughly 133 A of output current, which typically drives an interconnection OCPD on the order of 175 A (final size must match the inverter nameplate output current and listing instructions). This is a large backfeed relative to a 200 A panel and will drive a code compliance check for the load-side bus limitation under NEC 705.12.

The proposed 60 kWh BESS will also require an interconnection breaker and disconnecting means, but the required breaker size cannot be determined from the one-line information provided because the charge/discharge power (kW) and PCS output current are not shown. The BESS interconnection OCPD must be sized from the PCS nameplate continuous AC output current and installed per the manufacturer’s instructions.

Given the 200 A service equipment size, a load-side backfeed of the PV (and especially PV plus BESS) is likely to exceed allowable bus loading unless the load-side connection method and ratings are specifically engineered for compliance (for example, reduced main, dedicated bus rating allowances, or other NEC-permitted methods). The most practical pathway to maintain capacity to existing loads is typically a supply-side connection ahead of the 200 A main, using listed service-entrance equipment and tap rules, with utility-required metering and an accessible, lockable disconnect.

A protection and interconnection review is required to confirm available fault current at 240 V, verify that all added breakers and devices meet or exceed the 10 kA short-circuit rating noted for the panel, and confirm grounding and bonding provisions (including use of the equipment grounding bar and any required bonding method). The 120/240 V high-leg delta configuration also requires verification of correct phase referencing and that any 120 V derived circuits do not inadvertently land on the high leg.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 94,960 kWh per year. Using the U.S. EPA’s Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:”

- Carbon dioxide (CO_2): 40,681 lbs (18.45 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 40,833 lbs (18.52 metric tons) avoided annually
- Nitrogen oxides (NO_x): 31.527 lbs (14.30 kg) avoided annually
- Sulfur dioxide (SO_2): 1.899 lbs (0.86 kg) avoided annually

CASE 3: BESS Only

Critical Load Identification

Based on the facility classification as a community center and the absence of any explicitly identified critical loads in the one-line diagram, only code-mandated emergency and legally required standby systems are considered. Per NEC 700 and NFPA 72, emergency loads are limited to egress illumination and fire alarm systems. NEC 701 applies to legally required standby systems such as limited security, communications, or access control where required by local authority. No mission-critical or healthcare-related loads are evident. A critical load equal to 12.5 kW is established, representing 25 percent of the total connected load, which is consistent with typical life-safety and legally required standby obligations for this facility type.

Required Backup Duration

For a community center, maintaining continuous operation of alarm systems, emergency communications, lighting, and fuel dispensing is essential to guarantee mission readiness. According to NFPA 110 (Section 4.2 and 7.12.1), emergency power supply systems (EPSS) must provide a minimum of 2 hours of operation at full rated load. However, for critical public safety facilities, most Authorities Having Jurisdiction (AHJs) and best practice guidelines require at least 4 hours of backup capacity to ensure firefighters can respond to emergencies during extended outages.

Battery Capacity & Infrastructure

The battery energy storage system is sized to support a continuous emergency demand of 12.5 kW for the required 4-hour duration, resulting in a usable energy capacity of 50 kWh. The battery power rating is set equal to the critical load at 12.5 kW, as no higher peak demand is identifiable from the drawings. Integration would require an automatic transfer mechanism to isolate emergency circuits from normal power, routing through an emergency distribution section fed from the BESS. Breaker sizing, bus capacity verification, and coordination with the existing load center are required to ensure the emergency feeder can accommodate the additional source without exceeding panel ratings.

Capital Expenditures

For a BESS in the 12.5 kW / 50 kWh range, typical installed costs fall in the low to mid six-figure range, depending on manufacturer, enclosure type, and installation conditions. Electrical scope inferred from the one-line includes addition of a dedicated BESS breaker, possible panelboard modifications, an automatic transfer device, control wiring, and required disconnecting means. Structural mounting, clearances, and labeling per NEC Article 706 would also contribute to capital cost.

Operating Expenses

Operating expenses for an emergency-only BESS are relatively low. Annual costs are primarily associated with periodic inspection, functional testing, and firmware or control maintenance. Battery degradation occurs over time due to calendar aging rather than cycling, given the limited operational profile. Cell replacement or augmentation may be required near end of life, typically aligned with the manufacturer’s warranted life.

Return on Investment & Qualitative Benefits

While a conventional financial return cannot be directly applied to this case, the value of a BESS for a community center is framed in terms of resilience, reliability, and compliance. Such systems are designed to ensure uninterrupted operation of life-safety and legally required standby equipment during extended utility outages. The benefits include maintaining safe egress, preserving fire alarm functionality, and ensuring compliance with NFPA 110, NFPA 70, and NFPA 72.

However, for this particular facility, the justification for a BESS must be evaluated against existing backup assets. If generator capacity already exceeds the critical load requirement, the incremental resilience provided by the BESS may be limited relative to cost, shifting the decision toward redundancy preference or policy-driven resilience objectives.

Technical Considerations

Key technical considerations include verifying available bus capacity within the existing load center, compliance with the 120 percent load-side interconnection rule if applicable, and potential breaker or feeder upgrades to accommodate the additional source. Emergency and normal circuits must remain segregated through an appropriate transfer scheme. A short-circuit and coordination study is required to confirm fault duties remain within equipment ratings, and transfer sequencing must be validated to prevent backfeed conditions. UL 9540A fire propagation considerations and room placement constraints must be addressed prior to final system selection and installation.

Decision Matrix and Scenario Comparison

In order to determine the most appropriate scenario for the site, four scenarios were developed and analyzed: business as usual (Case 0), installing a PV system only (Case 1), installing PV with a BESS (Case 2), and installing a BESS only (Case 3). Each case was evaluated in terms of resilience value, capital and operating expenditures, energy savings, payback period, and technical feasibility. The decision matrix summarizes the comparative performance of these options.

Criteria	Case 0: Baseline	Case 1: PV Only	Case 2: PV + BESS	Case 3: BESS Only
Resilience Benefit	None	Limited (daytime only)	Moderate (self-consumption, limited outage support if configured)	High (but redundant due to existing 125 kW generator)
CAPEX ($)	0	~$95k–$109k (before ITC) ~$57k–$65k (after ITC)	~$95k–$109k PV + ~$67.5k BESS Net ~$65k (ITC + SGIP)	Possible 100% cover under SGIP
OPEX ($/yr)	Current $24k	~$1,036	~$1,636	~$600–$1,000
Annual Utility Bill ($)	~$24,424	~$11,815	~$2,783	~$24,424 (no reduction)
Annual Savings ($)	–	~$11,069	~$20,641	Minimal (non-financial)
Payback Period	–	~6 years	~4 years	No ROI
GHG Reduction	None	~18.5 $MTCO_2e$ avoided annually	Same as Case 1	None
Technical Feasibility	Already in place	Requires service-side or bus upgrade for NEC 705 compliance	Requires service-side interconnection and storage integration	Technically feasible

Table 3. Scenario Comparison

Conclusion

Based on the comparative analysis, **Case 2 (PV + BESS)** emerges as the preferred scenario for the site. While Case 1 (PV-only) provides meaningful utility cost reductions and a relatively short payback period, the addition of battery storage under Case 2 delivers substantially higher annual savings, significantly reduces grid dependency, and enhances overall system flexibility. Most importantly, the availability of the **Self-Generation Incentive Program (SGIP)** materially changes the economic outcome by potentially covering **up to 100% of the battery system cost**, resulting in a faster payback and a stronger long-term financial position.

Under current assumptions, the PV + BESS configuration nearly eliminates annual energy costs, reducing the utility bill from approximately $23,424 to about $2,783 per year. Even after accounting for combined PV and BESS operating expenses, the system generates net annual savings of roughly $19,600, leading to a simple payback period of approximately **4 years**, which is materially shorter than the PV-only alternative. This accelerated payback makes Case 2 the most economically attractive option despite its higher nominal system complexity.

In addition, SGIP funding creates an opportunity to **increase the battery capacity by approximately 50 kWh beyond the base economic sizing**, with the incremental storage potentially also covered by SGIP incentives. This additional capacity can be reserved specifically for **resilience purposes**, allowing the system to support critical loads during outages without compromising the battery's primary economic dispatch function. As a result, Case 2 uniquely combines strong financial performance with improved resilience at minimal incremental capital cost.

Summary of Strategy & Benefits

The selected strategy focuses on installing a rooftop PV system sized to offset approximately **110–115% of the facility's annual energy consumption**, paired with a battery energy storage system optimized for energy shifting and resilience. This approach achieves the following benefits:

- **Resilience Enhancement:** Provides on-site stored energy that can be allocated to critical loads during outages, with the option to dedicate an additional ~50 kWh exclusively for resilience.
- **Incentive Optimization:** Leverages ITC direct pay for PV and SGIP incentives for storage, potentially covering **100% of the battery system cost** and reducing overall project risk.
- **Economic Performance:** Reduces annual utility costs by approximately **85–90%**, delivering the highest net annual savings among all evaluated scenarios.
- **Accelerated Payback:** Achieves a simple payback period of approximately **4 years**, driven primarily by SGIP-funded battery storage.
- **Environmental Impact:** Offsets approximately **17–18 metric tons of CO_2 emissions annually**, contributing directly to local and regional climate goals.
- **Operational Practicality:** Minimizes exposure to volatile utility rates while avoiding unnecessary reliance on grid exports under NEM 3.

Next Steps

To advance the project, the following steps are recommended:

1. **Detailed Design & Site Assessment:** Conduct a 30% design phase evaluation, including structural assessment of the roof, electrical interconnection details, and shading analysis
2. **Vendor Quotations:** Obtain updated vendor quotes for PV system equipment, installation, and interconnection to refine cost estimates beyond NLR benchmarks
3. **Permitting & Interconnection:** Coordinate with Southern California Edison (SCE) to complete the interconnection study and ensure compliance with NEM 3 tariff rules
4. **Finalize Incentive Applications:** Submit applications for the 30% ITC (direct pay) to secure federal funding and reduce upfront capital cost
5. **Procurement & Installation:** Issue RFPs for procurement and construction, selecting qualified contractors with experience in municipal PV installations
6. **Commissioning & Monitoring:** Upon installation, perform commissioning tests, integrate the system with monitoring platforms, and establish an operations and maintenance (O&M) plan to ensure reliable long-term performance

Appendix

Incentive Programs

This section outlines how the incentive programs function and provides relevant information about them. Specific application of these programs to presented scenarios is explored in previous sections.

Inflation Reduction Act

The Inflation Reduction Act of 2022 stands as a significant piece of legislation designed to strengthen the United States' commitment to fighting climate change by making considerable investments in renewable energy. A key feature of the Inflation Reduction Act is its financial incentives, namely the Investment Tax Credit (ITC) and the Production Tax Credit (PTC), which aim to accelerate the adoption of renewable energy technologies.

The ITC allows for a significant tax credit for investments in renewable energy technologies, including solar panels and wind turbines, directly reducing the upfront cost of these systems. This makes renewable projects more financially viable and attractive to investors and consumers alike. On the other hand, the PTC provides a per-kilowatt-hour tax relief for the production of energy from renewable sources, incentivizing the operation and expansion of renewable energy facilities.

Notably, Inflation Reduction Act programs have been subject to change in recent legislation. Presented here are active opportunities as of the time of the report.

Production Tax Credit

The Production Tax Credit (PTC) within the framework of the Inflation Reduction Act offers considerable financial incentives for renewable energy projects, primarily designed to decrease the federal income tax liability based on the electricity produced per kilowatt-hour.

The PTC directly reduces the federal income tax for taxable entities. Furthermore, for non-taxable entities such as local governments, educational institutions, or nonprofit organizations, the PTC allows these credits to be monetized, facilitating their involvement in renewable energy initiatives. This provision is applicable for projects that become operational between January 1, 2023, and December 31, 2032, providing a broad window for planning and implementation.

Projects located in designated low-income energy communities receive further incentives. The PTC is structured to be claimable annually for a decade from the start date of operations of the qualifying renewable system, providing long-term financial support. This current structure of the PTC is set to continue through the end of 2024. Starting from January 1, 2025, the credit system will transition to a technology-neutral format, broadening the scope to include a wider array of technologies and fostering a more inclusive approach to renewable energy incentives.

As of the date of this report, the program is still active but solar projects must have “begun construction” by July 4, 2026.

The City project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

Investment Tax Credit

The Investment Tax Credit (ITC) established under the Inflation Reduction Act offers a powerful incentive for deploying renewable energy technologies by providing a reduction in federal tax liability. This reduction is calculated as a percentage of the capital investment made in eligible energy systems. Taxpayers can apply the ITC to their federal income tax for the year the technology is installed, significantly decreasing their tax burden.

Starting January 1, 2023, special provisions enable tax-exempt entities such as local governments and nonprofits to receive direct payments equivalent to the value of the credit. This arrangement improves the liquidity and financial feasibility of renewable projects for these organizations. The scope of eligible technologies under the ITC is broad, encompassing solar panels, wind turbines, fuel cells, and other renewable energy systems.

As of 2025, the Investment Tax Credit (ITC) for solar projects is set at 30% of the eligible costs, encompassing both the equipment and installation expenses. This rate is scheduled to decrease to 26% in 2033 and further to 22% in 2034. Systems rated under 1 megawatt (MW) qualify for the full 30% without having to comply with additional requirements; larger systems will only receive the full amount if they meet specific labor requirements. These include paying prevailing wages to workers during construction and using apprentices to perform a portion of the total construction hours (15% after 2023). Bonus credits are available based on site location, e.g. low-income communities.

The ITC is set to continue delivering these benefits at its current rate until 2032, contingent upon meeting the specific project criteria laid out in the act. Looking ahead, post-2024, the ITC will transition to a technology-neutral system, which will be applicable to all zero-emissions technologies, reflecting a shift towards a more inclusive and adaptable approach to supporting renewable energy development.

HHZP project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

As of the date of this report, the program is still active but critical deadlines for project eligibility and complete operability are quickly approaching in 2026 and 2027, respectively.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) offers financial incentives to non-residential customers of utility Company to encourage the adoption of energy storage systems. These systems help businesses prepare for power outages that may occur due to weather, emergencies, or other unforeseen events. The SGIP funding is authorized through 2024, with incentives structured to decrease over time as funding milestones are reached or as more participants enter the program.

Non-residential customers have access to three types of SGIP rebates: General Market, Equity, and Equity Resilience. Furthermore, SGIP incentives are significantly higher for vulnerable or disadvantaged communities through the Equity and Equity Resilience categories.

Incentives are typically paid upfront for residential systems upon project completion and site verification, while nonresidential systems may receive half upfront with the balance paid based on the system's performance over time. Eligibility for SGIP incentives extends to residential, commercial, industrial, agricultural, and municipal customers of specific utilities including Pacific Gas & Electric, Southern California Edison, SoCalGas, San Diego Gas & Electric, and those managed by the Center for Sustainable Energy.

To be eligible for this rebate, a facility must satisfy two conditions: firstly, it must fall under the category of a government agency, educational institution, non-profit organization, or small business. Secondly, it must fulfill at least one of the following requirements: be located in a Disadvantaged Community (DAC), be situated in a census tract where the Median Household Income of the Statewide Median Income or be situated in California Indian Country.

On the other hand, the equity resilience rebate offers a rate, covering a percentage of the cost of an average energy storage system. To qualify for this rebate, a facility must meet certain requirements. Firstly, it must have experienced two or more utility Public Safety Power Shut-offs (PSPS), or it should be located in a Tier 2 or 3 High Fire Threat District (HFTD) and serve customers in DACs or Low Income Communities. Secondly, it must fulfill at least one of the following additional criteria:

- Be a police station, fire station, emergency response provider, emergency operations center, 911 call center, medical facility, private and public natural gas, electric, water, wastewater, or flood facility, jail or prison, utility-designated PSPS assistance center, cooling center, homeless shelter.

- Be a grocery store, supermarket, or corner store with less than $15 million in annual gross receipts.
- Be an Independent Living Center or a Food Bank.

Modeling Assumptions

The modeling conducted for this feasibility study was based on standard industry benchmarks, available site data, and conservative assumptions to ensure realistic projections. The following key assumptions were applied:

1. **Energy Consumption Baseline** – Historical hourly load data (8,760 points) from the facility was consolidated to represent a typical annual profile. This served as the reference for sizing PV and BESS systems.
2. **PV System Costs** – Capital expenditure (CAPEX) and operations and maintenance (OPEX) values were derived from the National Laboratory of the Rockies (NLR) 2024–2025 benchmarks for commercial rooftop systems. PV CAPEX was assumed at $1.75–$2.00/Wdc, with OPEX at ~$19/kW-year.
3. **BESS Costs** – Battery energy storage CAPEX was modeled using NLR 2025 benchmarks at ~$350/kWh. OPEX was assumed at ~$40/kW-year, covering maintenance, monitoring, and lifecycle management.
4. **ITC Incentives** – A 30% Investment Tax Credit (direct pay) was assumed, reducing upfront project cost. No additional low-income or disadvantaged community adders were included, since the site does not qualify.
5. **Performance Parameters** –
    - PV generation modeled with HelioScope using site tilt, azimuth, and shading factors.
    - Battery modeled with 90% round-trip efficiency and daily cycling where applicable.
    - Energy inflation rate of 3% annually applied to utility costs.
6. **Utility Tariff** – The analysis used the most recent Southern California Edison tariff, **TOU-GS-2 Option D**, as published in the file *ELECTRIC_SCHEDULES_TOU-GS-2_2025*. It was assumed under the current **NEM 3** framework. Exported PV energy was valued at ~25% of retail rate. Since tariff structures and prices are subject to future changes, the financial outcomes presented here should be viewed as indicative estimates rather than fixed projections.
7. **Infrastructure** – Electrical interconnection feasibility was preliminarily evaluated using customer-provided single-line diagrams. Minor breaker adjustment (600 A to 500 A) was assumed to comply with NEC 705.12 120% busbar rule for PV backfeed.
8. **Environmental Impact** – Greenhouse gas (GHG) reduction estimates were calculated using EPA eGRID emission factors for the CAMX subregion, applied to modeled PV generation.

Disclaimer: These figures are rough estimates intended for feasibility-level evaluation. If more precise values are required, additional detail must be developed through site-specific engineering, vendor quotations, and utility coordination during the advanced design phase.

Net Energy Metering

Net Energy Metering (NEM) in California is a billing arrangement that allows residential and commercial customers who generate their own electricity, primarily through solar photovoltaic (PV) systems, to receive credit for the surplus energy they contribute to the grid. This system is designed to incentivize the use of renewable energy sources by offsetting the cost of electricity consumption with the energy produced by these installations.

Under NEM, when a solar system generates more electricity than is consumed, the excess energy is sent back to the utility grid, and the customer earns credits. These credits can then be used to offset the cost of energy drawn from the grid when the solar system isn't producing enough to meet the customer's demand, like during nighttime or cloudy days. The rules, rates, and credits under NEM can vary over time, with different iterations such as NEM 1, 2, and the latest NEM 3, each having specific regulations and compensation structures for solar energy production and exchange.

The transition from NEM 2 to NEM 3 in California, which was effective on April 14, 2023, introduced significant changes in the net metering policies for utility customers with photovoltaic (PV) systems. These changes impact several aspects, particularly the economics of energy arbitrage between PV system owners and the utility. Here's a summary of the key changes:

1) **Reduction in Export Rates:** Under NEM 3, there's a substantial reduction in the rates for excess electricity exported onto the grid by solar systems. This rate has been reduced by approximately 75%, thereby lowering the overall savings for home solar systems and increasing the payback period. This change is a shift from the traditional one-to-one offset of net metering policies, where the price of a kWh of electricity pushed onto the grid was equal to the price of a kWh pulled off the grid.
2) **Implementation of Electrification Rates:** Customers enrolling in NEM 3 are required to use electrification rates instead of regular Time-of-Use (TOU) rates. These electrification rates feature higher on-peak charges and lower off-peak charges, along with a fixed charge of $15 per month. The peak rate period remains from 4 pm to 9 pm.
3) **Export Compensation Based on Avoided Cost Calculator (ACC):** Export compensation under NEM 3 is determined by California's ACC, with specific export rates for every combination of Month, Hour, and Weekday or Weekend. The export value is lowest in the middle of the day when solar energy is abundant on the grid and highest during peak summer demand periods. Notably, the export rates are significantly lower than retail rates during the hours when PV systems are most productive (10 am – 3 pm). To maintain the financial viability of solar PV systems, customers in PG&E and SCE service territories receive an adder on top of the ACC rate, ranging between 2.2 and 9 cents depending on location and customer class.
4) **Shift to a Cost Avoidance System:** NEM 3 introduces a cost avoidance system for exported electricity. This system pays customers the lowest amount a company can pay under the Public Utility Regulatory Policies Act of 1978 (PURPA), which is significantly less than the typical retail rate. This results in customers receiving, on average, 75% less for the electricity they sell back to the grid, with rates varying by month and by hour.
5) **Grandfathering NEM 2 under NEM 3:** Under the recent NEM 3 policy in California, existing customers with a photovoltaic (PV) system installed under NEM 2 can retain the benefits and terms of their NEM 2 agreement, a process known as "grandfathering." However, these customers are restricted from replacing or adding capacity to their PV systems if they wish to maintain their NEM 2 status, as any significant modifications would require transitioning to the terms of NEM 3.

The Net Energy Metering (NEM) 3.0 policy introduces transformative changes, particularly enhancing the value of utilizing Battery Energy Storage Systems (BESS) for owners of solar power systems. A significant aspect of NEM 3.0 is the reduction in compensation rates for surplus electricity fed back into the grid by solar systems, now down to 75%. This adjustment shifts the financial dynamics, making it less lucrative to export excess solar energy to the grid. Instead, storing this surplus energy in a BESS and utilizing it when energy costs are higher becomes a more financially savvy approach.

The utility of BESS extends beyond merely optimizing the use of solar energy. It offers several additional advantages, such as providing backup power during utility blackouts, mitigating charges associated with demand peaks, and enabling energy arbitrage. Energy arbitrage under this system allows for the charging of BESS not only with excess solar energy but also with cheaper grid energy during low-cost periods. This stored energy can then be used in lieu of more expensive grid power at peak times, effectively reducing reliance on utility-supplied energy. Consequently, NEM 3.0 not only promotes more efficient use of solar energy but also broadens the scope of BESS applications, contributing to a more versatile and resilient energy management strategy.

AECOM



Microgrid Feasibility Study
City of Menifee

Site:
Maintenance Operations Center
27860 Bradley Road, Sun City, CA 92586

February 2026

Delivering a better world

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Executive Summary

This study appraises the viability and benefits of distributed energy resource implementation scenarios at the subject site. Four scenarios were analyzed, and key metrics are summarized below.

Case	Components	CAPEX (After Incentives)	Utility Savings ($/yr)	Payback Period (yrs)	GHG Reduction ($MTCO_2e/yr$)
1	PV	$23k – $27k	~$5.1k	~6	~6.7
2	PV + BESS	~$61.6k	~$10.4k	~9	~6.7
3	BESS	~$8.8k	—	—	—
0	Business-as-usual	$0	$0	N/A	0

Note: All values are approximate and based on feasibility-level assumptions.

Scenario Overview

- **Case 1: Photovoltaic (PV) array –** Introduces on-site generation and provides meaningful utility cost reductions with moderate resilience benefits limited to daytime operation.
- **Case 2: PV + battery energy storage system (BESS)** – Combines on-site generation with energy storage, enabling load shifting and limited backup capability. While this option improves resilience relative to Case 1, it does so at a significantly higher capital cost and longer payback period.
- **Case 3: BESS only** – Provides targeted resilience by supplying emergency power to critical loads during utility outages. This option is designed exclusively for backup operation and does not pursue energy cost savings or emissions reduction.
- **Case 0: Business-as-usual** – Maintains full dependence on utility service with no improvement in resilience, cost stability, or emissions reduction.

Considering the comparative analysis presented in this study, Case 3 (BESS) is identified as the recommended scenario. This recommendation is driven by the following considerations:

- The BESS-only approach delivers direct resilience benefits at the lowest capital cost among all DER options.
- The system is sized specifically to support critical loads, aligning with emergency preparedness and life safety priorities rather than energy arbitrage or bill reduction.
- This strategy avoids introducing unnecessary system complexity or long financial payback periods that are not aligned with resilience-driven investments.

This recommendation is made with the explicit acknowledgment that **detailed electrical one-line diagrams and backup system documentation were not available** at the time of this study. As such, the analysis conservatively assumes that **no permanent backup power system is currently in place**. Confirmation of existing generators, transfer schemes, or emergency distribution would be required during subsequent design phases.

Recommended Next Steps

1. Advance to a 30% design phase to confirm electrical, structural, and space constraints.
2. Obtain vendor-specific quotations for PV and BESS equipment to refine cost and performance assumptions.
3. Initiate SGIP application and reservation processes to secure storage incentives.
4. Proceed with permitting and interconnection applications under the applicable Net Energy Metering (NEM 3) framework.
5. Develop a final construction and procurement plan aligned with the City's budget cycle.

The intent of this assessment is to support a data-driven decision by demonstrating that a BESS (Case 3) offers the most favorable balance of economic performance, incentive optimization, emissions reduction, and resilience enhancement for the subject site under current regulatory and market conditions.

Background

Purpose

In recent years, especially within the past decade, the impacts of extreme heat and wildfires have been profound through the Inland Empire. Power service disruptions have been increasing in frequency and severity throughout Riverside County, affecting the availability of essential services and community resources.

In 2023, the Western Riverside Council of Governments (WRCOG) received an award (Grant Agreement OPR23145) from the Adaptation Planning Grant Program of the California Governor's Office of Land Use & Climate Innovation Integrated Climate Adaptation and Resilience Program. This program provides funding to help fill local, regional, and tribal planning needs, provides communities the resources to identify climate resilience priorities, and supports the development of a pipeline of climate-resilient infrastructure projects across the state.

As part of this grant-funded project, the Energy Resilience Plan 2.0, WRCOG commissioned microgrid feasibility studies for its member agencies. These studies serve to provide valuation of a potential microgrid at a community-essential facility, as designated by the member agency.

The site selected for the City of Menifee is the Maintenance Operations Center located at 27860 Bradley Rd, Sun City, CA 92586.

This study presents key insights and findings from the evaluation of distributed energy resource (DER) scenarios, including photovoltaic (PV) array and battery energy storage system (BESS) components, at the subject site. It includes analysis of the site's historic energy demand profile and appraises potential PV array and BESS sizing and siting scenarios accordingly. Notably, the study includes assessment of the generation and storage requirements to support the site's critical loads to enable resilience for a specified number of hours during power service disruptions.

Furthermore, this study outlines the financial implications of self-generation, including estimated cost savings, return on investment (ROI), and potential financing options for the project.

It is important to note that this study serves as a preliminary technical and financial assessment. Its purpose is to provide the City of Menifee with the information to make an informed decision on whether to proceed to next phases of microgrid implementation before committing to detailed engineering design and further investment.

Adaptation Planning Grant Program

As communities in California experience more frequent, prolonged, and severe impacts from climate change, communities and governments at all scales are developing strategies and implementing actions to build a climate-resilient future. However, many jurisdictions, especially under-resourced communities in California, lack the capacity, tools, guidance, and resources to effectively prepare for climate impacts.

The Adaptation Planning Grant Program addresses this capacity gap by providing funding to help fill planning needs, providing communities with the resources to identify climate resilience priorities, and supporting the development of climate resilience projects across the state. The Adaptation Planning Grant Program enables communities to climate risk and adaptation considerations into planning activities and prepare for climate readiness and resilience in the long term.

The Adaptation Planning Grant is part of the Integrated Climate Adaptation and Resiliency Program (ICARP) housed within the Governor's Office of Land Use and Climate Innovation. ICARP advances statewide climate adaptation and resilience by coordinating investments, partnerships, and climate science to ensure people, natural systems, and the built environment are protected, prepared, and thrive in the face of climate change.

Through direct and equity-focused investments and resources, ICARP helps build climate adapted and equitable communities in California, with a focus on solutions that address the impacts of climate change and reduce greenhouse gas emissions. ICARP works to advance these priorities across all levels of government by developing

actionable science and research; providing guidance, tools, and technical assistance; and administering climate resilience-focused grant programs.

Learn more: https://lci.ca.gov/climate/icarp/

Modeling Methodology

This section defines the criteria for sizing the PV array and BESS system components, detailing general parameters, technical requirements, and expected performance criteria.

PV Modeling

1. **Data Inputs**
    - **Solar Resource**: Hourly or sub-hourly irradiance data (e.g., typical meteorological year or on-site measurements)
    - **Site-Specific Factors**: Tilt angle, azimuth, shading analysis, and available roof/ground space
2. **Simulation Approach**
    - Use of HelioScope software to estimate hourly PV production
3. **Sizing Criteria**
    - **Capacity Target**: The sizing criteria are based on 110% of the facility's current annual energy consumption. This approach aims to fully offset the facility's energy usage with the PV array while incorporating an additional 10% capacity to accommodate future demand growth. However, the final system capacity is constrained by the area designated as available by the client.
    - **Performance Ratio**: Evaluate Performance Ratio to ensure consistent system output
    - **Energy Production**: Hourly, daily, monthly, and annual PV generation forecasts
    - **Load Matching**: Amount of PV energy that directly offsets site load vs. excess exported to the grid

BESS Modeling

1. **Data Inputs**
    - **Load Profile**: Detailed electricity consumption and demand patterns
    - **PV Production Profile**: From the PV modeling results
    - **Energy Duration for Resilience**: Determine the critical loads that the BESS will support during islanding operations
2. **Operational Modes**
    - **Energy Shifting / Excess PV Storage**: Battery charges when PV output exceeds site demand, discharges when site demand is high.
    - **Resilience (Standalone BESS)**: Sized to support critical loads during outages
3. **Sizing Criteria**
    - **Capacity (kWh)**: Based on required autonomy (energy shifting, peak shaving, or resilience duration)
    - **Max Discharge/Charge Rate (kW)**: Aligned with site load peaks, PV generation surpluses, and emergency power needs
4. **Simulation Approach**
    - Hourly or sub-hourly dispatch modeling to maximize economic benefit (e.g., demand charge reductions or avoided peak rates)

- Incorporate battery round-trip efficiency, self-discharge, and operational constraints (e.g., partial charge strategies)

5. **Output**

   - **Discharge/Charge Profiles**: Hourly modeling of how the battery is utilized
   - **Cost Savings**: Reduction in energy and demand charges or avoided grid cost
   - **Backup Duration**: If sized for resilience, the total hours/days of critical load coverage

Assumptions

AECOM collected facility data through a request for information process. Energy consumption factors and facility characteristics were identified and integrated in analysis. AECOM used these combined datasets to confirm energy utility consumption baselines.

In performing the analysis, AECOM made the following assumptions:

- This report refers to the Maintenance Operations Center located at 27860 Bradley Rd, Sun City, CA 92586.
- The monthly and annual electricity consumption is determined using load profile data in the client-provided file "SCE_Usage_8003963032_09-01-24_to_09-30-25" This file contains 35040 load profile data points, which are then consolidated into an 8760 load profile dataset.
- AECOM utilized the Levelized Cost of Energy (LCOE) for the installed cost per watt of PV installations and BESS, as sourced from the National Laboratory of the Rockies (NLR). This data was used to estimate the hypothetical cost of installing the PV array and BESS at the site, as detailed in this report. For an accurate cost estimation, it is necessary to obtain vendor quotes, which are subject to change due to market-dependent time windows. These quotations are typically conducted during the 60% design phase, at which point there is an understanding of the specific equipment ratings and brands to be used.
- This report does not evaluate the site's existing electrical infrastructure, as the customer did not provide information about the electrical system. However, since this is a feasibility study, an on-site assessment is required to make a definitive determination. A site visit should be conducted during the advanced design phase, typically at the 30% design stage, to confirm site-specific conditions.
- AECOM has estimated the potential PV generation capacity based on the client-identified available area, as documented in the client-provided file "*PW MOC Map.*" However, a site assessment is required in later project phases, typically at the 30% design stage, to ensure that the site has the necessary infrastructure for PV array installation. This includes evaluating civil structures, load-bearing capacity, particularly for rooftop installations, and other critical conditions necessary for successful implementation.
- This report uses a regionalized estimate of general production (kWh) to calculate the amount of greenhouse gas emissions avoided through PV generation. The calculation is based on the U.S. EPA Emissions & Generation Resource Integrated Database (eGRID).
- This report clarifies that other charges such as connection fees, required service charges, and taxes remain unchanged. The analysis focuses solely on the bill components directly affected by the installation of PV and BESS under the NEM 3 framework.
- The critical load used for the resilience analysis was estimated as a percentage of the facility's maximum annual demand, as identified from the 8760-hour load profile dataset provided by the client. This peak demand value was combined with facility-type based assumptions consistent with typical emergency and life-safety requirements for general facility operations. In the absence of detailed electrical one-line diagrams and load schedules, this approach provides a conservative, code-informed estimate suitable for feasibility-level planning and is intended to be validated and refined during the 30% design phase.

AECOM utilized the following tools in conducting the analysis:

- AECOM Internal Tools: Proprietary tools developed by AECOM for analyzing energy patterns and evaluating system performance in simulated environments. These tools are designed to assess energy costs for applications such as peak shaving, energy trading, etc. in DER implementations.
- HelioScope: Web-based software tool used for the design and performance analysis of photovoltaic systems. It combines system layout design with energy simulation, allowing users to model rooftop, ground-mounted, and canopy PV installations. The software factors in module placement, tilt, azimuth, shading, and local weather data to provide accurate estimates of system capacity and expected energy generation.

Site Information

This study is conducted for the Maintenance Operations Center located at 27860 Bradley Rd, Menifee, CA 92586. The site currently consumes about **31,244 kWh of electricity per year**,

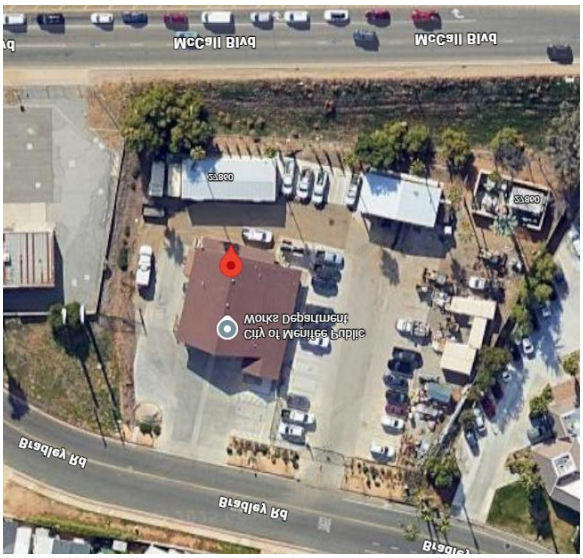


Figure 1. Site Location

The City indicated that PV was not viable on the east side of the building, as depicted in Figure 2.



Figure 2. No-Go Areas for PV

Incentive Programs

AECOM has identified three key incentive programs that could benefit the subject site, focusing on renewable energy production and advanced energy storage systems.

The Investment Tax Credit (ITC) and Production Tax Credit (PTC) are federal incentives that reduce the cost of renewable energy projects. ITC offers a tax credit based on a percentage of upfront investment costs, while PTC provides a per-kilowatt-hour credit for electricity generated over time.

Production Tax Credit

Under this initiative, the project is eligible for a tax credit ranging from 0.3 cents to 1.5 cents per installed kWh. The specific value of the credit is determined by several factors, including the project's adherence to certain requirements such as complying with labor standards and using domestic materials.

The PTC program pays for each kilowatt-hour produced over a 10-year period, with government entities receiving the benefit as direct pay instead of a tax credit. For this project, with an estimated 343,680 kWh per year, the best case at 1.5 ¢/kWh would yield about $5,155 annually, totaling around $51,552 over 10 years.

Investment Tax Credit

The City may utilize either the ITC or the PTC, but not both. Because the project has not yet begun construction, the ITC remains the preferred alternative. In this scenario, the project is assumed to be located within a qualifying low-income census tract, enabling eligibility for the additional 10 percent bonus credit.

Under the Low-Income Communities Bonus Credit Program, projects located within a designated low-income community, as defined by the 2016–2020 census tract boundaries in Figure 3, receive an additional 10 percentage points added to the base ITC. This increases the total credit from 30 percent to 40 percent of the eligible project cost.

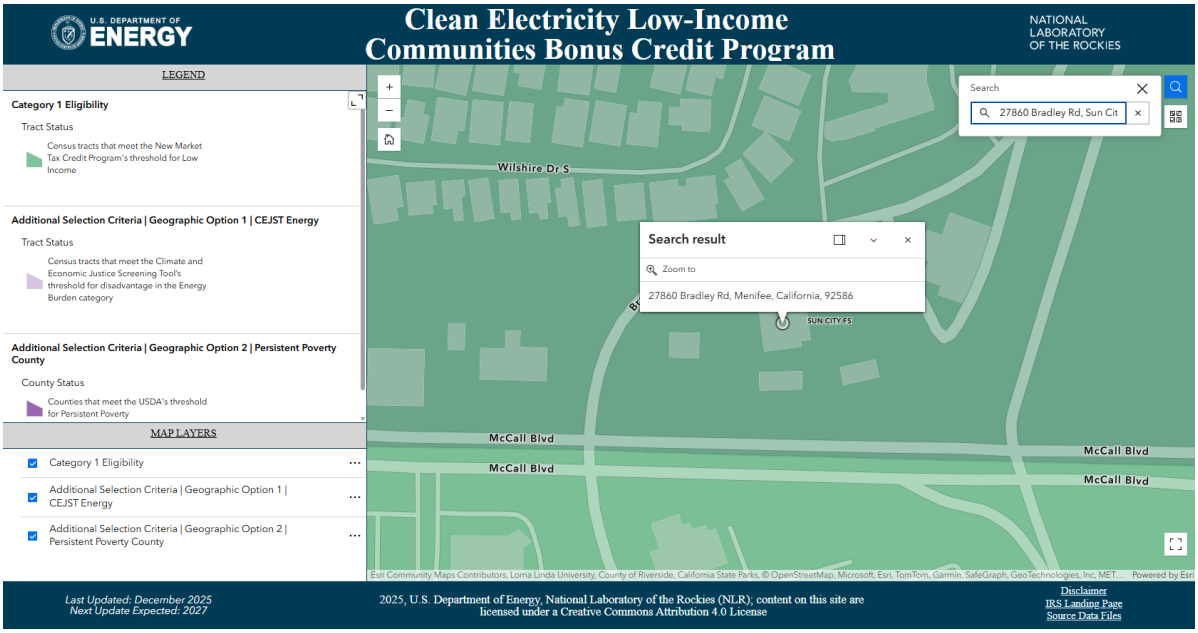


Figure 3. Clean Electricity Low-Income Communities Bonus Credit Program Map

Using NLR's CAPEX range of $1.75–2.00 /W direct current (DC), the proposed 22 kW DC PV system would cost between $38,780 and 44,320. With a 40 percent ITC, the resulting direct-pay benefit increases to $15,512 - 17,728, reducing the project's upfront capital requirements accordingly.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) is California's primary incentive designed to reduce the upfront cost of energy storage systems. The program has three levels:

- **General Market:** For projects located outside Disadvantaged Communities (DAC). Typical incentive: $0.10 /Wh.
- **Equity (DAC):** For projects located within a DAC. Incentive: $0.85/Wh.
- **Equity Resilience**: For critical facilities within a DAC and in PSPS or high fire-risk zones. Incentive: $1.00/Wh.

In Case 1, the project site is outside a DAC, so it only qualifies for the General Market level. Using an NLR-based cost of $450/kWh, a 100-kWh battery would cost approximately $45,000. With the General Market incentive of $0.10 /Wh, the project would receive about $10,000, resulting in a net battery cost of roughly $35,000.

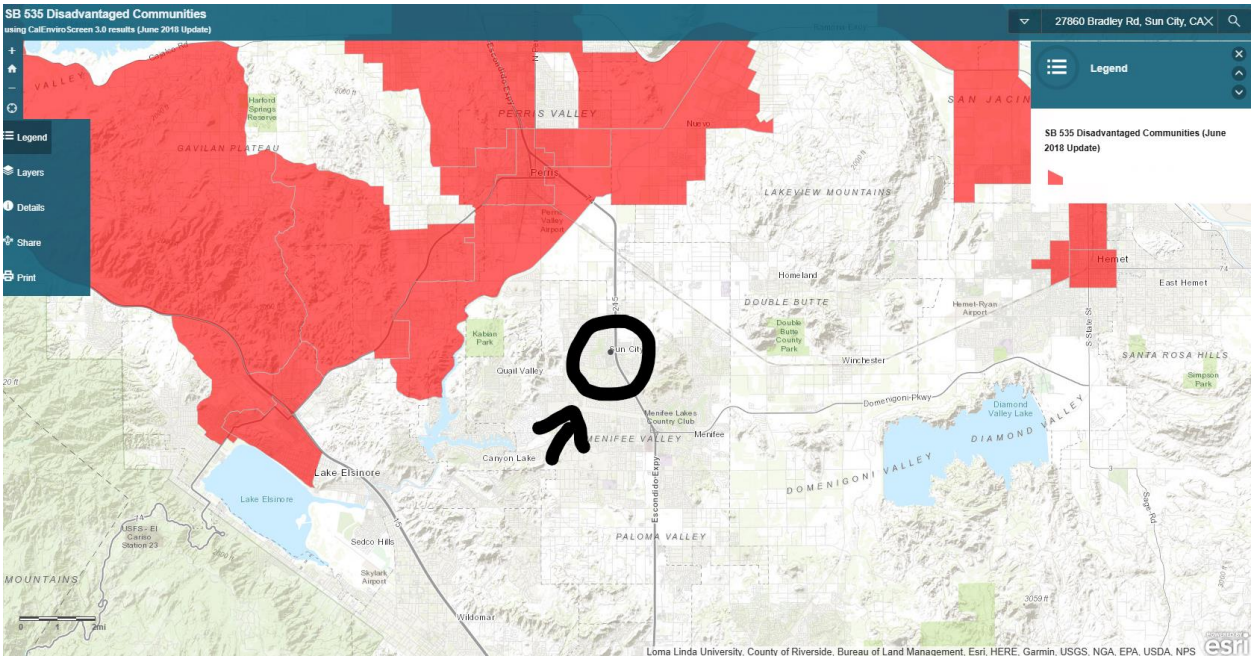


Figure 4. SB 535 Disadvantaged Communities Map

Scenarios & Analysis

Case 0: Current Situation (Baseline)

Tariff & Contract Type

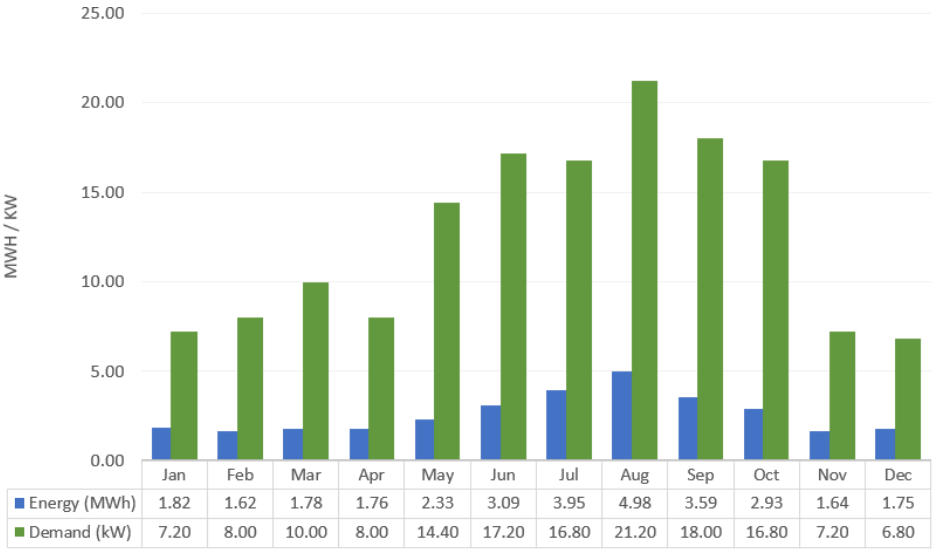
The site is currently served by Southern California Edison (SCE) under the TOU-GS-2 tariff, which is intended for small to medium commercial customers. However, for the purposes of this study, the TOU-GS-2-D tariff is considered a more suitable option for a microgrid installation, as it provides clearer time-of-use price signals and demand charge structures that better align with on-site generation and battery dispatch strategies, improving overall system optimization and economic performance. This rate structure separates costs into energy charges (based on kilowatt-hours consumed) and demand charges (based on the highest kilowatt demand registered during the billing cycle). In addition, prices vary by time-of-use periods—on-peak, mid-peak, and off-peak—so the timing of energy use significantly affects overall costs.

Being on this tariff means the site's operating expenses are directly tied not only to how much energy is consumed but also to when it is consumed and how high the peak demand reaches.

The tariff cost presents the costs as totals (delivery + bundle). The prices were used as the basis for this study. While they may fluctuate slightly month to month depending on market conditions, these variations are generally minor.

Monthly & Annual Energy Consumption and Demand

The facility currently consumes 31,244 kWh annually, with August being the highest month at about 4,980 kWh and February the lowest at about 1,620 kWh. In terms of demand, August records the peak at around 21.2 kW, while November is the lowest at about 7.2 kW. The following graph presents this historical data for the 2024–2025 period.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Energy (MWh)	1.82	1.62	1.78	1.76	2.33	3.09	3.95	4.98	3.59	2.93	1.64	1.75
Demand (kW)	7.20	8.00	10.00	8.00	14.40	17.20	16.80	21.20	18.00	16.80	7.20	6.80

Figure 5. Historic Site Energy Profile

Monthly & Annual Energy Costs

The site currently spends about $12,494 per year in energy and demand cost, with approximately $8,046 in energy costs and $6,340 in demand charges, based on tariff TOU-GS-2-D simulation. For this analysis, we are focusing only on energy and demand costs, as these are the components directly impacted by the installation of a PV system.

Case 1: PV Only

Installed Capacity & Location

The PV system for the site was sized to offset approximately 110% of current consumption, with the goal of fully offsetting present usage while reserving about 10% additional capacity for future growth. The placement areas for the PV installation were identified according to customer requirements. The system capacity is estimated at 22.2 kW direct current (DC), with an expected annual production of about 34,368 kWh.

Figure 6 presented the modeled energy production throughout the year, and Figure 7 identifies the designated PV installation areas on the site.

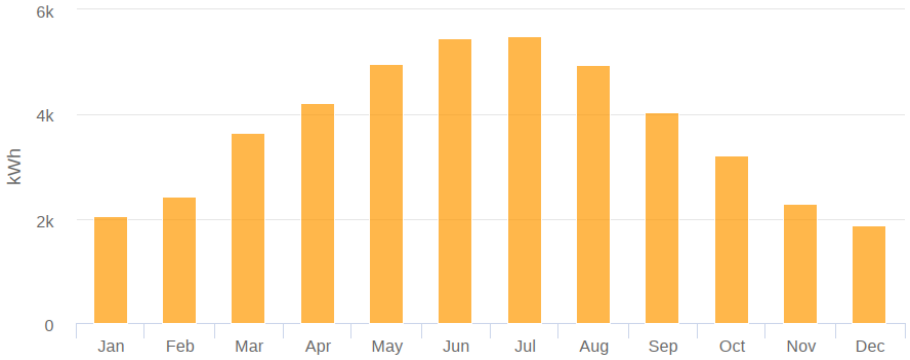


Figure 6. Modeled PV Production

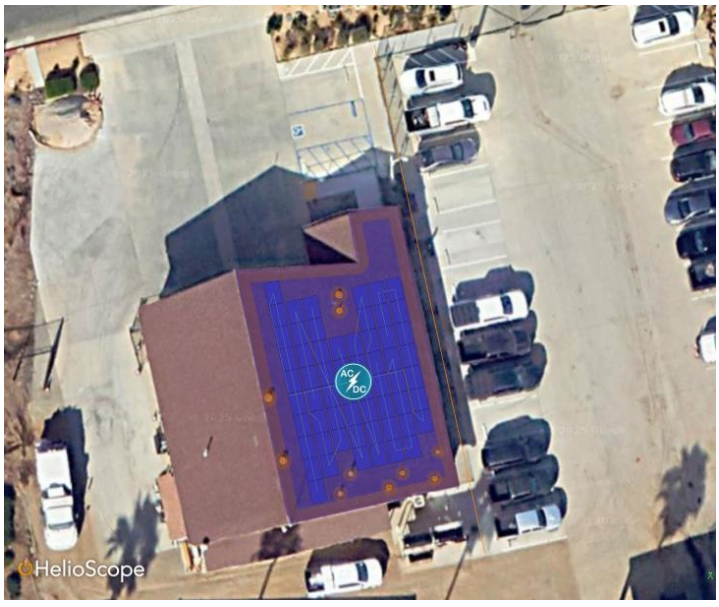


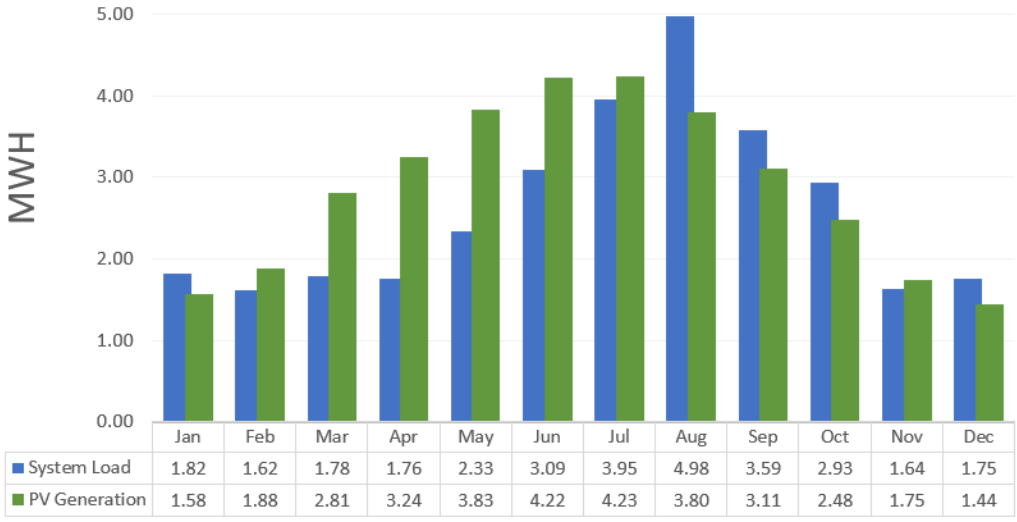
Figure 7. Modeled PV Installation Areas

Modeled PV Production

The modeled PV system is projected to generate an average of **2,684 kWh per month**, with an estimated **annual production of 34,368 kWh**.

This scenario doesn't include a BESS, so the excess energy produced need be exported to the utility, which requires entering a Net Energy Metering (NEM) contract with the utility service provider. Under the currently available NEM tariff, NEM 3.0, exported electricity is credited at dynamic rates that vary by month, hour of day, and weekday, ranging from as low as $0.01/kWh during midday hours to over $1.00/kWh during peak evening hours in high-demand months like August and September. This study has calculated projected benefits from this arrangement.

Figure 8 compares historic monthly energy consumption and modeled PV generation. Not all solar energy will be consumed on-site, as excess daytime production may exceed demand and be exported to the grid, while nighttime demand cannot be covered since there is no generation after sunset and no battery to store the excess in this scenario.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
System Load	1.82	1.62	1.78	1.76	2.33	3.09	3.95	4.98	3.59	2.93	1.64	1.75
PV Generation	1.58	1.88	2.81	3.24	3.83	4.22	4.23	3.80	3.11	2.48	1.75	1.44

Figure 8. Modeled PV Output vs. Site Demand

Capital Expenditures

Based on NLR benchmark CAPEX values for commercial rooftop solar, the estimated cost to install a 22.2 kW DC PV system in Menifee County, California falls in the range of **$1.75 to $2.00 per watt DC**. This translates to a total investment of **approximately $38,780 – 44,320 for the complete system**.

These figures include typical equipment, installation, and soft costs, reflecting average market conditions for commercial-scale projects. Actual costs may vary slightly depending on site-specific conditions such as roof structure, permitting, interconnection requirements, and labor. However, the NLR benchmarks provide a reliable basis for estimating the capital cost of a system of this size and type in the region.

Operating Expenses

According to NLR's 2024 benchmark data, the annual operations and maintenance (OPEX) cost for commercial rooftop PV systems is about $19 per kW DC. For a 22.2 kW DC system, this translates to an **estimated yearly OPEX of roughly $421** covering routine maintenance, monitoring, and related operational expenses.

Economic Metrics

The analysis shows that installing a PV system at the site under NEM3 provides measurable financial benefits by offsetting both energy and demand charges. Without solar, the facility currently spends about $12,494 annually on utility costs. With the PV system in operation, the energy cost is reduced to approximately $4,909 per year, while the demand cost drops to about $3,112 per year. In addition, the system generates excess electricity during the day that cannot be fully consumed on-site. Under NEM3 rules, this exported energy represents an additional benefit of roughly $601 annually.

Taken together, these reductions and export credits bring the facility's total utility bill down to **$7,420 per year**, achieving an **overall savings of about 84%** compared to current expenses

Payback Period and Return on Investment

The financial analysis shows that without PV, the facility spends approximately $12,494 per year on utility costs. With a 22.2 kW DC PV system installed, the annual cost is reduced to about $7,420, resulting in yearly savings of roughly $5,074. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system is estimated at $44,320, but with the 40 percent ITC direct pay, the net investment is reduced to approximately $26,592. In addition, the system carries an annual OPEX of $421, which slightly offsets the yearly savings. Taking these factors into account, the project generates a net benefit of about $5,074 minus 421 per year after OPEX. This results in a simple payback period of approximately 6 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross Savings ($)	Net Savings after OPEX ($)	Cumulative Cash Flow ($)
1	5,075	4,654	-21,938
2	5,227	4,794	-17,145
3	5,384	4,937	-12,207
4	5,546	5,085	-7,122
5	5,712	5,238	-1,884
6	5,883	5,395	3,512
7	6,060	5,557	9,069
8	6,242	5,724	14,792
9	6,429	5,895	20,688
10	6,622	6,072	26,760
15	7,676	7,039	59,966
20	8,899	8,161	98,461

Table 1. Return on Investment w/ 3% Inflation: Case 1

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 34,368 kWh per year. Using the U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:

- Carbon dioxide (CO_2): 14,723.2512 lbs (6.6784 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 14,778.2400 lbs (6.7033 metric tons) avoided annually
- Nitrogen oxides (NO_x): 11.4102 lbs (5.1756 kg) avoided annually
- Sulfur dioxide (SO_2): 0.6874 lbs (0.3118 kg) avoided annually

These avoided emissions constitute a material environmental benefit attributable to on-site renewable generation, reducing fossil-fuel related grid pollutants on an annual basis.

Case 2: PV + BESS

System Components

This scenario assumes the same PV array described in Case 1 and a BESS sized for surplus PV production. The day with the highest energy surplus in our simulation occurred on Jul-6, during which the PV system produced 149.55 kWh, the site consumed 38.00 kWh, and the resulting surplus was 111.55 kWh. For size the BESS, we ran several iterations based on the available surplus energy and applied an algorithm that simulates the charge and discharge cycles of one year. This techno-financial analysis indicates that the optimal BESS capacity is approximately 100 kWh.

This simulation factor ensures that even under variations in production or demand, all possible excess solar energy generated during the day can be stored. The stored energy is then available for use at night or during periods when PV production does not fully cover the site's demand.

By doing so, most of the units of solar energy produced on-site are consumed daily by the facility, preventing as little as possible any export to the grid.

Modeled Energy Flows

By installing a 100 kWh battery, we ensure that all the energy generated on-site is consumed by the facility itself. The charge and discharge profile of the battery is designed so that any PV surplus during the day is immediately stored in the battery rather than exported to the grid. Later, if the site demand exceeds the PV generation while there is still energy stored in the battery, the deficit is supplied from the battery.

This operational strategy minimizes or even eliminates consumption from the utility, since the PV and battery combination is prioritized to cover the load at all times. On an annual basis, the system is expected to produce slightly more energy than the site requires, leaving a surplus of around 10%, but this excess is negligible in terms of the overall utility bill.

Capital Expenditures

According to NLR benchmark data, the capital expenditure (CAPEX) for a commercial-scale 22.2 kW DC rooftop PV system in Menifee, California is estimated at $26,592 under ITC incentive, based on installation costs of $1.75–2.00 per watt DC.

For storage, NLR's 2025 cost projections indicate a CAPEX of $450 per kWh for the high-cost scenario. Applying this benchmark to a commercial-scale **100 kWh BESS** represents an investment of **roughly $61,592** and under the SGIP program this amount can be partially covered, effectively funding 14% of the BESS.

Together, the combined CAPEX for the PV and BESS systems is estimated at $61,592representing the expected upfront investment for a commercial solar-plus-storage project of this size.

Operating Expenses

According to NLR benchmark data, the annual operations and maintenance (OPEX) cost for a commercial-scale 22.2 kW DC rooftop PV system is estimated at $400 USD.

NLR data indicates an operating cost of approximately $4 per kW-year. For a commercial-scale 100 kWh battery system, this results in an annual OPEX of about $71,592 USD.

Together, the **combined OPEX for the PV and BESS systems is approximately $821 per year**, covering routine maintenance, monitoring, and system management.

Economic Metrics

The financial analysis shows that without PV + BESS, the facility spends approximately $12,494 per year on utility costs. With a 22 kW DC PV system and 100 kWh BESS system installed, the annual cost is reduced to about $ 7,420 resulting in **yearly savings of roughly $5,074**. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system under ITC and SGIP incentives is estimated at $61,592. In addition, the system carries an annual OPEX of $821 Taking these factors into account, the combined system generates a net benefit of

about $4,253 per year after OPEX. This results in a simple payback period of approximately 9 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Payback Period and Return on Investment

Year	Gross-Savings ($)	Net-Savings after OPEX ($)	Cumulative Cash Flow ($)
1	10,435	9,614	-78,570
2	10,748	9,902	-68,668
3	11,070	10,199	-58,468
4	11,402	10,505	-47,963
5	11,745	10,821	-37,143
6	12,097	11,145	-25,997
7	12,460	11,479	-14,518
8	12,834	11,824	-2,694
9	13,219	12,179	9,484
10	13,615	12,544	22,028
15	15,784	14,542	90,624
20	18,298	16,858	170,145

Table 2. Return on Investment w/ 3% Inflation: Case 2

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 34,368 kWh per year. Using the U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:

- Carbon dioxide (CO_2): 14,723.2512 lbs (6.6784 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 14,778.2400 lbs (6.7033 metric tons) avoided annually
- Nitrogen oxides (NOx): 11.4102 lbs (5.1756 kg) avoided annually
- Sulfur dioxide (SO_2): 0.6874 lbs (0.3118 kg) avoided annually

CASE 3: BESS Only

Critical Load Identification

For a Works Department facility, the code driven emergency and standby power scope is generally limited to life safety functions under NEC 700 and NFPA 72, including required means of egress illumination and the fire alarm system power supply. NEC 701 legally required standby loads are typically not triggered unless a local ordinance explicitly requires continuity for specific functions such as public safety communications or similarly mandated systems. Based on this facility classification and the absence of any documented legally required standby obligations, the critical load is set at 6.0 kW.

Battery Capacity & Infrastructure

The BESS real power rating is set to 6.0 kW to cover the peak emergency demand when a separate peak value is not identified. Energy capacity is set to 24 kWh to sustain the emergency load for 4 hours. Implementation requires a dedicated emergency distribution path that is isolated from normal loads, typically via an ATS or equivalent transfer scheme that feeds only the emergency panel(s). The emergency feeder and protective device ratings must be coordinated to support 6.0 kW continuous discharge and to ensure selective coordination for NEC 700 emergency circuits where applicable.

Capital Expenditures

Using cost benchmarks published by the National Laboratory of the Rockies (NLR), the estimated capital cost (CAPEX) for a 25 kWh / 5 kW battery energy storage system is **approximately $8,750**. This figure includes the battery cabinets, inverter/PCS, microgrid controller with ATS, installation, protections, and engineering.

Operating Expenses

The expected **operating cost** (OPEX) is about $**100 per year**, also based on NLR reference values. This covers preventive maintenance, monitoring software, and NFPA 110 testing requirements. Battery replacement is typically required after 10–12 years of service.

Return on Investment & Qualitative Benefits

While a conventional financial return cannot be directly applied, the value of a BESS for a Works Department facility is framed in terms of resilience, reliability, and compliance. The system is intended to maintain uninterrupted operation of required life safety functions during extended utility outages, reducing safety risks and supporting compliance with NFPA 110 where an EPSS is required, NFPA 70 for emergency system separation and protection, and NFPA 72 for fire alarm power continuity. However, the justification must be evaluated against existing backup assets; if an existing generator already exceeds the critical load requirement, the incremental resilience provided by a BESS may be limited relative to cost, shifting the decision toward redundancy preference, policy, or long term reliability planning.

Technical Considerations

Key integration issues include ensuring the emergency source connection does not overload the serving bus, applying the NEC 705 120 percent load side interconnection limitation if the BESS is interconnected on the load side of service equipment, and verifying feeder and breaker ratings for continuous discharge at 6.0 kW. Emergency circuits must be separated from normal circuits with a defined transfer point and a dedicated emergency distribution arrangement so that non-emergency loads cannot be inadvertently energized. Final design requires short circuit and protective device coordination studies, verification of transfer sequence logic to prevent backfeed and nuisance trips, and confirmation of applicable listing and safety requirements including UL 9540A test based hazard mitigation as required by the AHJ and adopted codes.

Decision Matrix and Scenario Comparison

In order to determine the most appropriate scenario for the site, four scenarios were developed and analyzed: business as usual (Case 0), installing a PV system only (Case 1), installing PV with a BESS (Case 2), and installing a BESS only (Case 3). Each case was evaluated in terms of resilience value, capital and operating expenditures, energy savings, payback period, and technical feasibility. The decision matrix summarizes the comparative performance of these options.

Criteria	Case 0: Baseline	Case 1: PV Only	Case 2: PV + BESS	Case 3: BESS Only
Resilience Benefit	None	Limited (daytime only)	Moderate (self-consumption, some coverage)	High (emergency loads only, resilience focused)
CAPEX ($)	0	~$23,268 – $26,592 (After-ITC)	~$61,592	~$8,750
OPEX ($/yr)	Current	~$421	~$821	~$100
Annual Utility Bill ($)	~$12,494	~$7,420	~$2,060	~$12,494 (no reduction)
Annual Savings ($)	–	~$5,075	~$10,435	Minimal (non-financial)
Payback Period	–	~6 years	~9 years	No ROI
GHG Reduction	None	~6.7 metric tons CO_2e / yr	Same as Case 1	None
Technical Feasibility	Already in place	Feasible, standard PV interconnection	Feasible, PV + storage integration	Feasible, emergency-only system

Table 3. Scenario Comparison

Conclusion

Based on the comparative analysis, **Case 3 (BESS)** emerges as the recommended strategy for this site. While PV-only and PV + BESS configurations provide measurable economic and environmental benefits, we understand that the primary objective for this facility is to **strengthen resilience and continuity of critical operations**, rather than to maximize energy cost savings.

The BESS-only scenario provides targeted backup power for identified critical loads at a **significantly lower capital cost** compared to PV-based solutions, while directly supporting the County's resilience planning goals. This approach prioritizes life safety and emergency functionality during utility outages without introducing unnecessary system complexity or long payback periods.

This recommendation is made under the assumption that **no existing permanent electrical backup system is in place**, as detailed electrical one-line diagrams and generator interconnection information were not available at the time of this study. The analysis therefore assumes a conservative condition in which the facility relies solely on utility service during normal operation and lacks dedicated emergency power for critical loads.

Under these assumptions, a modestly sized BESS configured exclusively for emergency loads represents a **cost-effective and scalable resilience investment**. If future design phases confirm the presence of existing backup assets, the BESS scope can be adjusted or integrated to enhance redundancy rather than replace existing systems.

Summary of Strategy & Benefits

The selected strategy focuses on installing a **battery energy storage system dedicated to resilience**, sized only to support critical loads during utility outages. This approach delivers the following benefits:

- **Resilience Enhancement**: Provides uninterrupted power to critical life safety and emergency systems during outages, supporting County-wide resilience objectives.
- **Cost Effectiveness**: Requires substantially lower upfront capital investment compared to PV or PV plus BESS systems, making it an efficient use of public funds for resilience purposes.
- **Operational Simplicity**: Avoids the added operational, control, and maintenance complexity associated with on-site generation and energy arbitrage strategies.
- **Design Flexibility**: Can be expanded or integrated with future PV systems if economic or policy conditions change, without stranding initial investment.
- **Risk Reduction**: Reduces dependency on the utility grid during outages, improving facility readiness under emergency conditions.
- **Planning Alignment**: Reinforces the County's broader resilience framework by focusing investment on reliability and continuity rather than purely financial return.

Next Steps

To advance the project, the following steps are recommended:

1. **Detailed Design & Site Assessment:** Conduct a 30% design phase evaluation, including structural assessment of the roof, electrical interconnection details, and shading analysis
2. **Vendor Quotations:** Obtain updated vendor quotes for PV system equipment, installation, and interconnection to refine cost estimates beyond NLR benchmarks
3. **Permitting & Interconnection:** Coordinate with Southern California Edison (SCE) to complete the interconnection study and ensure compliance with NEM 3 tariff rules
4. **Finalize Incentive Applications:** Submit applications for the 30% ITC (direct pay) to secure federal funding and reduce upfront capital cost
5. **Procurement & Installation:** Issue RFPs for procurement and construction, selecting qualified contractors with experience in municipal PV installations
6. **Commissioning & Monitoring:** Upon installation, perform commissioning tests, integrate the system with monitoring platforms, and establish an operations and maintenance (O&M) plan to ensure reliable long-term performance

Appendix

Incentive Programs

This section outlines how the incentive programs function and provides relevant information about them. Specific application of these programs to presented scenarios is explored in previous sections.

Inflation Reduction Act

The Inflation Reduction Act of 2022 stands as a significant piece of legislation designed to strengthen the United States' commitment to fighting climate change by making considerable investments in renewable energy. A key feature of the Inflation Reduction Act is its financial incentives, namely the Investment Tax Credit (ITC) and the Production Tax Credit (PTC), which aim to accelerate the adoption of renewable energy technologies.

The ITC allows for a significant tax credit for investments in renewable energy technologies, including solar panels and wind turbines, directly reducing the upfront cost of these systems. This makes renewable projects more financially viable and attractive to investors and consumers alike. On the other hand, the PTC provides a per-kilowatt-hour tax relief for the production of energy from renewable sources, incentivizing the operation and expansion of renewable energy facilities.

Notably, Inflation Reduction Act programs have been subject to change in recent legislation. Presented here are active opportunities as of the time of the report.

Production Tax Credit

The Production Tax Credit (PTC) within the framework of the Inflation Reduction Act offers considerable financial incentives for renewable energy projects, primarily designed to decrease the federal income tax liability based on the electricity produced per kilowatt-hour.

The PTC directly reduces the federal income tax for taxable entities. Furthermore, for non-taxable entities such as local governments, educational institutions, or nonprofit organizations, the PTC allows these credits to be monetized, facilitating their involvement in renewable energy initiatives. This provision is applicable for projects that become operational between January 1, 2023, and December 31, 2032, providing a broad window for planning and implementation.

Projects located in designated low-income energy communities receive further incentives. The PTC is structured to be claimable annually for a decade from the start date of operations of the qualifying renewable system, providing long-term financial support. This current structure of the PTC is set to continue through the end of 2024. Starting from January 1, 2025, the credit system will transition to a technology-neutral format, broadening the scope to include a wider array of technologies and fostering a more inclusive approach to renewable energy incentives.

As of the date of this report, the program is still active but solar projects must have “begun construction” by July 4, 2026.

The City Site project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

Investment Tax Credit

The Investment Tax Credit (ITC) established under the Inflation Reduction Act offers a powerful incentive for deploying renewable energy technologies by providing a reduction in federal tax liability. This reduction is calculated as a percentage of the capital investment made in eligible energy systems. Taxpayers can apply the ITC to their federal income tax for the year the technology is installed, significantly decreasing their tax burden.

Starting January 1, 2023, special provisions enable tax-exempt entities such as local governments and nonprofits to receive direct payments equivalent to the value of the credit. This arrangement improves the liquidity and financial feasibility of renewable projects for these organizations. The scope of eligible technologies under the ITC is broad, encompassing solar panels, wind turbines, fuel cells, and other renewable energy systems.

As of 2025, the Investment Tax Credit (ITC) for solar projects is set at 30% of the eligible costs, encompassing both the equipment and installation expenses. This rate is scheduled to decrease to 26% in 2033 and further to 22% in 2034. Systems rated under 1 megawatt (MW) qualify for the full 30% without having to comply with additional requirements; larger systems will only receive the full amount if they meet specific labor requirements. These include paying prevailing wages to workers during construction and using apprentices to perform a portion of the total construction hours (15% after 2023). Bonus credits are available based on site location, e.g. low-income communities.

The ITC is set to continue delivering these benefits at its current rate until 2032, contingent upon meeting the specific project criteria laid out in the act. Looking ahead, post-2024, the ITC will transition to a technology-neutral system, which will be applicable to all zero-emissions technologies, reflecting a shift towards a more inclusive and adaptable approach to supporting renewable energy development.

HHZP project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

As of the date of this report, the program is still active but critical deadlines for project eligibility and complete operability are quickly approaching in 2026 and 2027, respectively.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) offers financial incentives to non-residential customers of utility Company to encourage the adoption of energy storage systems. These systems help businesses prepare for power outages that may occur due to weather, emergencies, or other unforeseen events. The SGIP funding is authorized through 2024, with incentives structured to decrease over time as funding milestones are reached or as more participants enter the program.

Non-residential customers have access to three types of SGIP rebates: General Market, Equity, and Equity Resilience. Furthermore, SGIP incentives are significantly higher for vulnerable or disadvantaged communities through the Equity and Equity Resilience categories.

Incentives are typically paid upfront for residential systems upon project completion and site verification, while nonresidential systems may receive half upfront with the balance paid based on the system's performance over time. Eligibility for SGIP incentives extends to residential, commercial, industrial, agricultural, and municipal customers of specific utilities including Pacific Gas & Electric, Southern California Edison, SoCalGas, San Diego Gas & Electric, and those managed by the Center for Sustainable Energy.

To be eligible for this rebate, a facility must satisfy two conditions: firstly, it must fall under the category of a government agency, educational institution, non-profit organization, or small business. Secondly, it must fulfill at least one of the following requirements: be located in a Disadvantaged Community (DAC), be situated in a census tract where the Median Household Income of the Statewide Median Income or be situated in California Indian Country.

On the other hand, the equity resilience rebate offers a rate, covering a percentage of the cost of an average energy storage system. To qualify for this rebate, a facility must meet certain requirements. Firstly, it must have experienced two or more utility Public Safety Power Shut-offs (PSPS), or it should be located in a Tier 2 or 3 High Fire Threat District (HFTD) and serve customers in DACs or Low Income Communities. Secondly, it must fulfill at least one of the following additional criteria:

- Be a police station, fire station, emergency response provider, emergency operations center, 911 call center, medical facility, private and public natural gas, electric, water, wastewater, or flood facility, jail or prison, utility-designated PSPS assistance center, cooling center, homeless shelter.
- Be a grocery store, supermarket, or corner store with less than $15 million in annual gross receipts.

- Be an Independent Living Center or a Food Bank.

Modeling Assumptions

The modeling conducted for this feasibility study was based on standard industry benchmarks, available site data, and conservative assumptions to ensure realistic projections. The following key assumptions were applied:

1. **Energy Consumption Baseline** – Historical hourly load data (8,760 points) from the facility was consolidated to represent a typical annual profile. This served as the reference for sizing PV and BESS systems.
2. **PV System Costs** – Capital expenditure (CAPEX) and operations and maintenance (OPEX) values were derived from the National Laboratory of the Rockies (NLR) 2024–2025 benchmarks for commercial rooftop systems. PV CAPEX was assumed at $1.75–$2.00/Wdc, with OPEX at ~$19/kW-year.
3. **BESS Costs** – Battery energy storage CAPEX was modeled using NLR 2025 benchmarks at ~$350/kWh. OPEX was assumed at ~$40/kW-year, covering maintenance, monitoring, and lifecycle management.
4. **ITC Incentives** – A 30% Investment Tax Credit (direct pay) was assumed, reducing upfront project cost. No additional low-income or disadvantaged community adders were included, since the site does not qualify.
5. **Performance Parameters** –
    - PV generation modeled with HelioScope using site tilt, azimuth, and shading factors.
    - Battery modeled with 90% round-trip efficiency and daily cycling where applicable.
    - Energy inflation rate of 3% annually applied to utility costs.
6. **Utility Tariff** – The analysis used the most recent Southern California Edison tariff, **TOU-GS-2 Option D**, as published in the file *ELECTRIC_SCHEDULES_TOU-GS-2_2025*. It was assumed under the current **NEM 3** framework. Exported PV energy was valued at ~25% of retail rate. Since tariff structures and prices are subject to future changes, the financial outcomes presented here should be viewed as indicative estimates rather than fixed projections.
7. **Infrastructure** – Electrical interconnection feasibility was preliminarily evaluated using customer-provided single-line diagrams. Minor breaker adjustment (600 A to 500 A) was assumed to comply with NEC 705.12 120% busbar rule for PV backfeed.
8. **Environmental Impact** – Greenhouse gas (GHG) reduction estimates were calculated using EPA eGRID emission factors for the CAMX subregion, applied to modeled PV generation.

Disclaimer: These figures are rough estimates intended for feasibility-level evaluation. If more precise values are required, additional detail must be developed through site-specific engineering, vendor quotations, and utility coordination during the advanced design phase.

Net Energy Metering

Net Energy Metering (NEM) in California is a billing arrangement that allows residential and commercial customers who generate their own electricity, primarily through solar photovoltaic (PV) systems, to receive credit for the surplus energy they contribute to the grid. This system is designed to incentivize the use of renewable energy sources by offsetting the cost of electricity consumption with the energy produced by these installations.

Under NEM, when a solar system generates more electricity than is consumed, the excess energy is sent back to the utility grid, and the customer earns credits. These credits can then be used to offset the cost of energy drawn from the grid when the solar system isn't producing enough to meet the customer's demand, like during nighttime or cloudy days. The rules, rates, and credits under NEM can vary over time, with different iterations such as NEM 1, 2, and the latest NEM 3, each having specific regulations and compensation structures for solar energy production and exchange.

The transition from NEM 2 to NEM 3 in California, which was effective on April 14, 2023, introduced significant changes in the net metering policies for utility customers with photovoltaic (PV) systems. These changes impact

several aspects, particularly the economics of energy arbitrage between PV system owners and the utility. Here's a summary of the key changes:

1) **Reduction in Export Rates:** Under NEM 3, there's a substantial reduction in the rates for excess electricity exported onto the grid by solar systems. This rate has been reduced by approximately 75%, thereby lowering the overall savings for home solar systems and increasing the payback period. This change is a shift from the traditional one-to-one offset of net metering policies, where the price of a kWh of electricity pushed onto the grid was equal to the price of a kWh pulled off the grid.
2) **Implementation of Electrification Rates:** Customers enrolling in NEM 3 are required to use electrification rates instead of regular Time-of-Use (TOU) rates. These electrification rates feature higher on-peak charges and lower off-peak charges, along with a fixed charge of $15 per month. The peak rate period remains from 4 pm to 9 pm.
3) **Export Compensation Based on Avoided Cost Calculator (ACC):** Export compensation under NEM 3 is determined by California's ACC, with specific export rates for every combination of Month, Hour, and Weekday or Weekend. The export value is lowest in the middle of the day when solar energy is abundant on the grid and highest during peak summer demand periods. Notably, the export rates are significantly lower than retail rates during the hours when PV systems are most productive (10 am – 3 pm). To maintain the financial viability of solar PV systems, customers in PG&E and SCE service territories receive an adder on top of the ACC rate, ranging between 2.2 and 9 cents depending on location and customer class.
4) **Shift to a Cost Avoidance System:** NEM 3 introduces a cost avoidance system for exported electricity. This system pays customers the lowest amount a company can pay under the Public Utility Regulatory Policies Act of 1978 (PURPA), which is significantly less than the typical retail rate. This results in customers receiving, on average, 75% less for the electricity they sell back to the grid, with rates varying by month and by hour.
5) **Grandfathering NEM 2 under NEM 3:** Under the recent NEM 3 policy in California, existing customers with a photovoltaic (PV) system installed under NEM 2 can retain the benefits and terms of their NEM 2 agreement, a process known as "grandfathering." However, these customers are restricted from replacing or adding capacity to their PV systems if they wish to maintain their NEM 2 status, as any significant modifications would require transitioning to the terms of NEM 3.

The Net Energy Metering (NEM) 3.0 policy introduces transformative changes, particularly enhancing the value of utilizing Battery Energy Storage Systems (BESS) for owners of solar power systems. A significant aspect of NEM 3.0 is the reduction in compensation rates for surplus electricity fed back into the grid by solar systems, now down to 75%. This adjustment shifts the financial dynamics, making it less lucrative to export excess solar energy to the grid. Instead, storing this surplus energy in a BESS and utilizing it when energy costs are higher becomes a more financially savvy approach.

The utility of BESS extends beyond merely optimizing the use of solar energy. It offers several additional advantages, such as providing backup power during utility blackouts, mitigating charges associated with demand peaks, and enabling energy arbitrage. Energy arbitrage under this system allows for the charging of BESS not only with excess solar energy but also with cheaper grid energy during low-cost periods. This stored energy can then be used in lieu of more expensive grid power at peak times, effectively reducing reliance on utility-supplied energy. Consequently, NEM 3.0 not only promotes more efficient use of solar energy but also broadens the scope of BESS applications, contributing to a more versatile and resilient energy management strategy.

AECOM



Microgrid Feasibility Study
City of Moreno Valley

Site:
Moreno Valley Senior Center
25075 Fir Avenue, Moreno Valley, CA 92553

February 2026

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Executive Summary

This study appraises the viability and benefits of distributed energy resource implementation scenarios at the subject site. Four scenarios were developed and compared, with key metrics summarized below.

Case	Components	CAPEX ($)	Utility Savings (%/year)	Payback Period (years)	GHG Reduction ($MTCO_2e$/year)
1	PV	$189k–$216k ($129,600 net w/ ITC)	~48%	~5 years	38.4
2	PV + BESS	$129,600 net (PV + BESS fully funded by SGIP)	~90%	~3 years	38.4
3	BESS	~$123,750	No utility savings	No ROI	None
0	Business as usual	$0	None	–	None

- **Case 1:** Photovoltaic (PV) array: Provides onsite generation and meaningful bill reductions. Limited resilience.
- **Case 2**: PV array + battery energy storage system (BESS): Delivers the strongest performance across all metrics. Enables full solar self-consumption, deep utility cost reductions, and resilience through stored energy. Supported by 40 percent ITC and SGIP Equity incentives.
- **Case 3:** BESS: Provides short-term resilience but offers no financial benefits and duplicates capabilities already covered by the existing generator.
- **Case 0:** Maintains current utility dependence: No savings or resilience improvement.

Considering the above, detailed more in Sections 3 and 4, this study concludes that **Case 2** (PV array + BESS) scenario is the most suitable and cost-effective path forward, striking a balance between resilience capabilities, technical feasibility, and financial performance.

Recommended Next Steps

1. Advance to a 30 percent design phase with detailed site assessment, interconnection validation, and structural review for PV array and equipment placement.
2. Obtain vendor-specific quotations to refine cost estimates for PV modules, inverters, racking, and battery systems.
3. Initiate permitting and interconnection applications with Southern California Edison under the NEM 3.0 framework, verifying load-side or supply-side connection options based on switchboard capacity.
4. Secure federal incentives, specifically the 40 percent Investment Tax Credit (direct pay) and the SGIP Equity incentive covering the full cost of the 350 kilowatt-hour (kWh) BESS.
5. Prepare procurement and construction planning, coordinating installation schedules and ensuring contractor experience with commercial PV + storage projects.

The goal is that with these data-driven microgrid feasibility assessment findings, the City of Moreno Valley can make an informed decision regarding an appropriate resilience-improving investment at the subject site.

Background

Purpose

In recent years, especially within the past decade, the impacts of extreme heat and wildfires have been profound through the Inland Empire. Power service disruptions have been increasing in frequency and severity throughout Riverside County, affecting the availability of essential services and community resources.

In 2023, the Western Riverside Council of Governments (WRCOG) received an award (Grant Agreement OPR23145) from the Adaptation Planning Grant Program of the California Governor's Office of Land Use & Climate Innovation Integrated Climate Adaptation and Resilience Program. This program provides funding to help fill local, regional, and tribal planning needs, provides communities the resources to identify climate resilience priorities, and supports the development of a pipeline of climate-resilient infrastructure projects across the state.

As part of this grant-funded project, the Energy Resilience Plan 2.0, WRCOG commissioned microgrid feasibility studies for its member agencies. These studies serve to provide valuation of a potential microgrid at a community-essential facility, as designated by the member agency.

The site selected for the City of Moreno Valley is Senior Center located at 25075 Fir Ave, Moreno Valley, CA 92553

This study presents key insights and findings from the evaluation of distributed energy resource (DER) scenarios, including photovoltaic (PV) array and battery energy storage system (BESS) components, at the subject site. It includes analysis of the site's historic energy demand profile and appraises potential PV array and BESS sizing and siting scenarios accordingly. Notably, the study includes assessment of the generation and storage requirements to support the site's critical loads to enable resilience for a specified number of hours during power service disruptions.

Furthermore, this study outlines the financial implications of self-generation, including estimated cost savings, return on investment (ROI), and potential financing options for the project.

It is important to note that this study serves as a preliminary technical and financial assessment. Its purpose is to provide the City of Eastvale with the information to make an informed decision on whether to proceed to next phases of microgrid implementation before committing to detailed engineering design and further investment.

Adaptation Planning Grant Program

As communities in California experience more frequent, prolonged, and severe impacts from climate change, communities and governments at all scales are developing strategies and implementing actions to build a climate-resilient future. However, many jurisdictions, especially under-resourced communities in California, lack the capacity, tools, guidance, and resources to effectively prepare for climate impacts.

The Adaptation Planning Grant Program addresses this capacity gap by providing funding to help fill planning needs, providing communities with the resources to identify climate resilience priorities, and supporting the development of climate resilience projects across the state. The Adaptation Planning Grant Program enables communities to climate risk and adaptation considerations into planning activities and prepare for climate readiness and resilience in the long term.

The Adaptation Planning Grant is part of the Integrated Climate Adaptation and Resilience Program (ICARP) housed within the Governor's Office of Land Use and Climate Innovation. ICARP advances statewide climate adaptation and resilience by coordinating investments, partnerships, and climate science to ensure people, natural systems, and the built environment are protected, prepared, and thrive in the face of climate change.

Through direct and equity-focused investments and resources, ICARP helps build climate adapted and equitable communities in California, with a focus on solutions that address the impacts of climate change and reduce greenhouse gas emissions. ICARP works to advance these priorities across all levels of government by developing

actionable science and research; providing guidance, tools, and technical assistance; and administering climate resilience-focused grant programs.

Learn more: https://lci.ca.gov/climate/icarp/

Modeling Methodology

This section defines the criteria for sizing the PV array and BESS system components, detailing general parameters, technical requirements, and expected performance criteria.

PV Modeling

1. **Data Inputs**
    - **Solar Resource**: Hourly or sub-hourly irradiance data (e.g., typical meteorological year or on-site measurements)
    - **Site-Specific Factors**: Tilt angle, azimuth, shading analysis, and available roof/ground space
2. **Simulation Approach**
    - Use of HelioScope software to estimate hourly PV production
3. **Sizing Criteria**
    - **Capacity Target**: The sizing criteria are based on 110% the facility's current annual energy consumption. This approach aims to fully offset the facility's energy usage with the PV array while incorporating an additional 10% capacity to accommodate future demand growth. However, the final system capacity is constrained by the area designated as available by the client.
    - **Performance Ratio**: Evaluate Performance Ratio to ensure consistent system output
    - **Energy Production**: Hourly, daily, monthly, and annual PV generation forecasts
    - **Load Matching**: Amount of PV energy that directly offsets site load vs. excess exported to the grid

BESS Modeling

1. **Data Inputs**
    - **Load Profile**: Detailed electricity consumption and demand patterns
    - **PV Production Profile**: From the PV modeling results
    - **Energy Duration for Resilience**: Determine the critical loads that the BESS will support during islanding operations
2. **Operational Modes**
    - **Energy Shifting / Excess PV Storage**: Battery charges when PV output exceeds site demand, discharges when site demand is high.
    - **Resilience (Standalone BESS)**: Sized to support critical loads during outages
3. **Sizing Criteria**
    - **Capacity (kWh)**: Based on required autonomy (energy shifting, peak shaving, or resilience duration)
    - **Max Discharge/Charge Rate (kW)**: Aligned with site load peaks, PV generation surpluses, and emergency power needs
4. **Simulation Approach**
    - Hourly or sub-hourly dispatch modeling to maximize economic benefit (e.g., demand charge reductions or avoided peak rates)

- Incorporate battery round-trip efficiency, self-discharge, and operational constraints (e.g., partial charge strategies)

5. **Output**

   - **Discharge/Charge Profiles**: Hourly modeling of how the battery is utilized
   - **Cost Savings**: Reduction in energy and demand charges or avoided grid cost
   - **Backup Duration**: If sized for resilience, the total hours/days of critical load coverage

Assumptions

AECOM collected facility data through a request for information process. Energy consumption factors and facility characteristics were identified and integrated in analysis. AECOM used these combined datasets to confirm energy utility consumption baselines.

In performing the analysis, AECOM made the following assumptions:

- This report refers to the Moreno Valley Senior Center, located at 25075 Fir Ave, Moreno Valley, CA 92553.
- The monthly and annual electricity consumption is determined using load profile data in the client-provided file “Attachment A - Interval Usage Data.” This file contains 35040 load profile data points, which are then consolidated into an 8760 load profile dataset.
- AECOM utilized the Levelized Cost of Energy (LCOE) for the installed cost per watt of PV installations and BESS, as sourced from the National Laboratory of the Rockies (NLR). This data was used to estimate the hypothetical cost of installing the PV array and BESS at the site, as detailed in this report. For an accurate cost estimation, it is necessary to obtain vendor quotes, which are subject to change due to market-dependent time windows. These quotations are typically conducted during the 60% design phase, at which point there is an understanding of the specific equipment ratings and brands to be used.
- This report evaluates the site’s existing electrical infrastructure using customer-provided data on the main breaker and bus capacity, as documented in the client-provided file “ Moreno Valley Senior Center Plans 6 “ AECOM has assessed whether the existing electrical system can support the proposed PV array and BESS installation. However, as this is a feasibility study, an on-site assessment is required for a definitive determination. A site visit should be conducted during the advanced design phase, typically at the 30% design stage, to confirm site-specific conditions.
- AECOM has estimated the potential PV generation capacity based on the client-identified available area. However, a site assessment is required in later project phases, typically at the 30% design stage, to ensure that the site has the necessary infrastructure for PV array installation. This includes evaluating civil structures, load-bearing capacity, particularly for rooftop installations, and other critical conditions necessary for successful implementation.
- This report uses a regionalized estimate of general production (kWh) to calculate the amount of greenhouse gas emissions avoided through PV generation. The calculation is based on the U.S. EPA Emissions & Generation Resource Integrated Database (eGRID).
- This report clarifies that other charges such as connection fees, required service charges, and taxes remain unchanged. The analysis focuses solely on the bill components directly affected by the installation of PV and BESS under the NEM 3 framework.
- Energy exported to the utility is valued at approximately one quarter of the applicable retail electricity rate for the purposes of this analysis under NEM factors.

AECOM utilized the following tools in conducting the analysis:

- AECOM Internal Tools: Proprietary tools developed by AECOM for analyzing energy patterns and evaluating system performance in simulated environments. These tools are designed to assess energy costs for applications such as peak shaving, energy trading, etc. in DER implementations.
- HelioScope: Web-based software tool used for the design and performance analysis of photovoltaic systems. It combines system layout design with energy simulation, allowing users to model rooftop, ground-mounted, and canopy PV installations. The software factors in module placement, tilt, azimuth, shading, and local weather data to provide accurate estimates of system capacity and expected energy generation.

Site Information

This study is conducted for Moreno Valley Senior Center, located in 25075 Fir Ave, Moreno Valley, CA 92553 The site currently consumes about 176,564 kWh per year.

In terms of electrical infrastructure, the site is equipped with a main switchboard for a 120/208-volt (V), three-phase, four-wire service. The single-line notes specify bracing for 42,000 ampere interruption capacity (AIC) and a 1000-ampere (A), 100% rated bus with a 1000-amp automatic transfer switch (ATS) with switched neutral.

The service distributes power to feeder sections serving panels “LA,” “LAA,” “LK,” “LB” and “LC.” The load summary indicates approximately 274.5 kilowatt (kW) connected demand with an operating current near 763.1 A at 120/208 V. Feeder notes call for up to three conduits with four 400 MCM conductors in each, and additional runs using two conduits with 3×300 MCM, confirming copper feeders sized to a maximum of 400 MCM. The drawings show a housekeeping pad and grounding per detail, with a future generator connection provisioned through the ATS. Overall, the system uses copper conductors, a grounded electrode system, and adheres to the project’s stated bracing and service requirements.

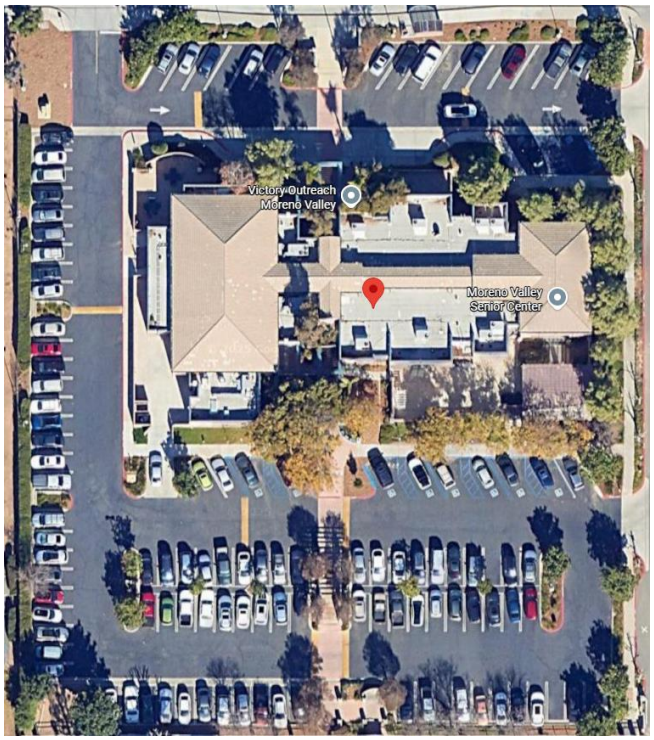


Figure 1. Site Location

Incentive Programs

AECOM has identified three key incentive programs that could benefit the subject site, focusing on renewable energy production and advanced energy storage systems.

The Investment Tax Credit (ITC) and Production Tax Credit (PTC) are federal incentives that reduce the cost of renewable energy projects. ITC offers a tax credit based on a percentage of upfront investment costs, while PTC provides a per-kilowatt-hour credit for electricity generated over time.

Production Tax Credit

Under this initiative, the project is eligible for a tax credit ranging from 0.3 cents to 1.5 cents per installed kWh. The specific value of the credit is determined by several factors, including the project's adherence to certain requirements such as complying with labor standards and using domestic materials.

The PTC program pays for each kilowatt-hour produced over a 10-year period, with government entities receiving the benefit as direct pay instead of a tax credit. For this project, with an estimated 197,615 kWh per year, the best case at 1.5 ¢/kWh would yield about $2,964 annually, totaling around $29,642 over 10 years.

Investment Tax Credit

The City may utilize either the ITC or the PTC, but not both. Because the project has not yet begun construction, the ITC remains the preferred alternative. In this scenario, the project is assumed to be located within a qualifying low-income census tract, enabling eligibility for the additional 10 percent bonus credit.

Under the Low-Income Communities Bonus Credit Program, projects located within a designated low-income community, as defined by the 2016–2020 census tract boundaries in Figure 3, receive an additional 10 percentage points added to the base ITC. This increases the total credit from 30 percent to 40 percent of the eligible project cost.

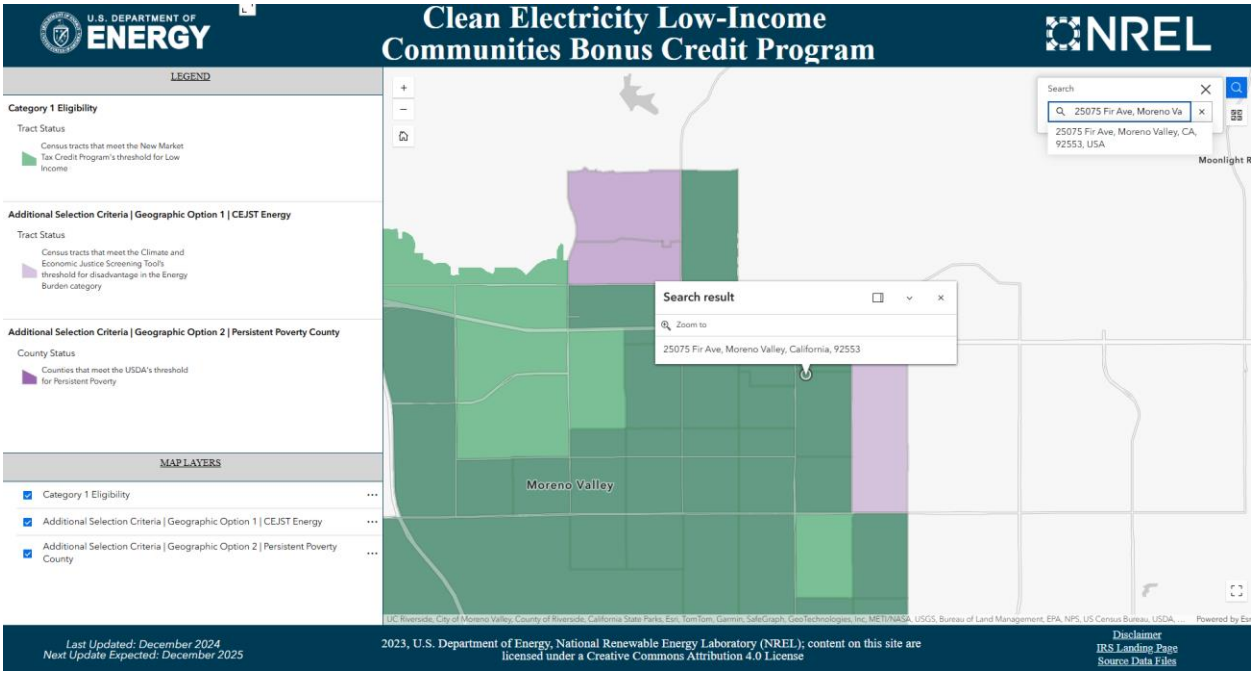


Figure 2. Clean Electricity Low-Income Communities Bonus Credit Program Map

Using NLR's CAPEX range of $1.75–2.00/W DC, the proposed 108 kW DC PV system would cost between $189,000 and 216,000. With a 40 percent ITC, the resulting direct-pay benefit increases to $75,600-86,400, reducing the project's upfront capital requirements accordingly.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) is California's primary incentive designed to reduce the upfront cost of energy storage systems. The program has three levels:

- General Market: For projects located outside Disadvantaged Communities (DAC). Typical incentive: $0.10/watt-hour (Wh).
- Equity (DAC): For projects located within a DAC. Incentive: $0.85/Wh.
- Equity Resilience: For critical facilities within a DAC and in PSPS or high fire-risk zones. Incentive: $1.00/Wh.

The project is located within a DAC, so it qualifies for the Equity level. Using an NLR-based cost of $450/kWh, the 300-kWh battery would cost approximately $122,000. At the Equity incentive rate of $0.85/Wh, the available support would total $297,000, which is sufficient to fully cover the system cost within SGIP's allowable limits.

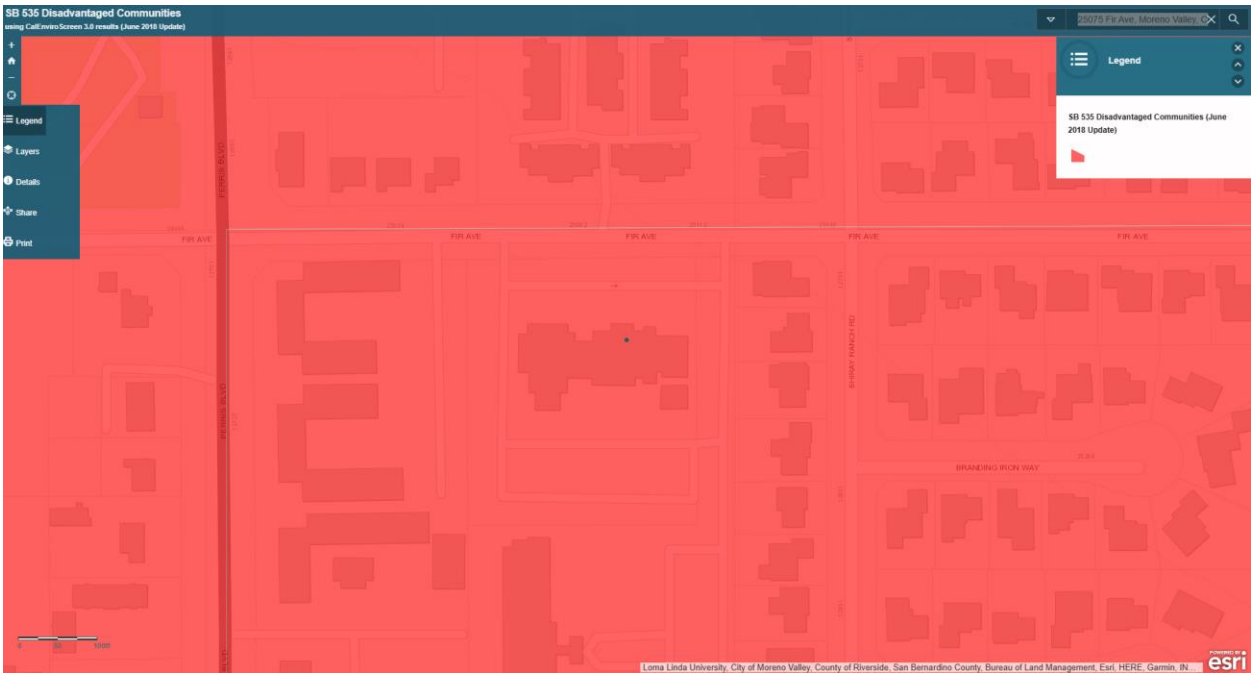


Figure 3. SB 535 Disadvantaged Communities Map

Scenarios & Analysis

Case 0: Current Situation (Baseline)

Tariff & Contract Type

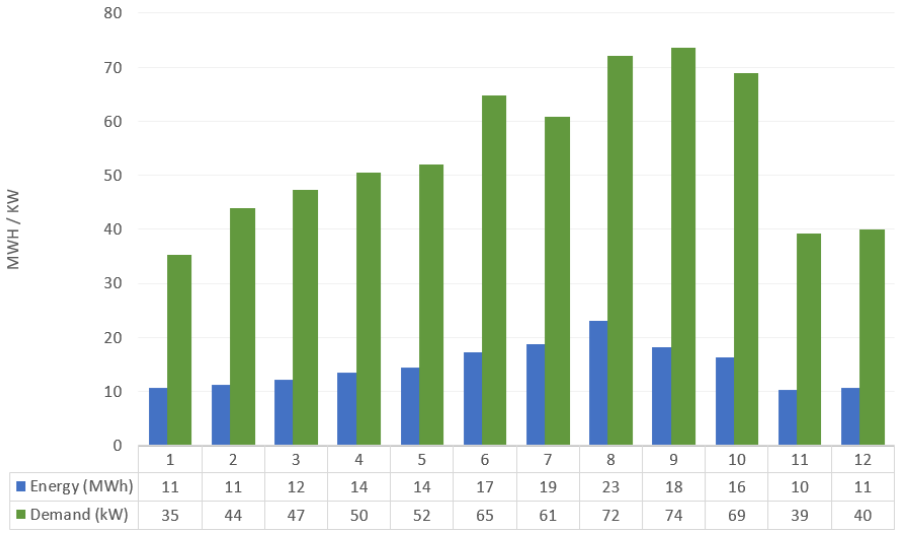
The site is currently served by Southern California Edison (SCE) under the TOU-GS-2-D tariff, which is designed for small to medium commercial customers. This rate structure separates costs into energy charges (based on kilowatt-hours consumed) and demand charges (based on the highest kilowatt demand registered during the billing cycle). In addition, prices vary by time-of-use periods—on-peak, mid-peak, and off-peak—so the timing of energy use significantly affects overall costs.

Being on this tariff means the site's operating expenses are directly tied not only to how much energy is consumed but also to when it is consumed and how high the peak demand reaches.

The tariff cost presents the costs as totals (delivery + bundle). The prices were used as the basis for this study. While they may fluctuate slightly month to month depending on market conditions, these variations are generally minor.

Monthly & Annual Energy Consumption and Demand

The facility currently consumes 176,564 kWh annually, with August being the highest month at about 23MWh and November the lowest at about 10 MWh. In terms of demand, September records the peak at around 74 kW, while November is the lowest at about 39 kW. The following graph presents this historical data for the 2024–2025 period.



	1	2	3	4	5	6	7	8	9	10	11	12
Energy (MWh)	11	11	12	14	14	17	19	23	18	16	10	11
Demand (kW)	35	44	47	50	52	65	61	72	74	69	39	40

Figure 4. Historic Site Energy Profile

Monthly & Annual Energy Costs

The site currently spends about $67,192 per year in energy and demand cost, with approximately $47,686 in energy costs and $26,207 in demand charges, based on tariff TOU-GS-2-D simulation. For this analysis, we are focusing only on energy and demand costs, as these are the components directly impacted by the installation of a PV system.

Case 1: PV Only

Installed Capacity & Location

The PV system for the site was sized to offset approximately 110% of current consumption, with the goal of fully offsetting present usage while reserving about 10% additional capacity for future growth. The placement areas for the PV installation were identified according to customer requirements. The system capacity is estimated at 108 kW direct current (DC), with an expected annual production of about 197,615 kWh.

Figure 6 presents the modeled energy production throughout the year, and Figure 7 identifies the designated PV installation areas on the site.

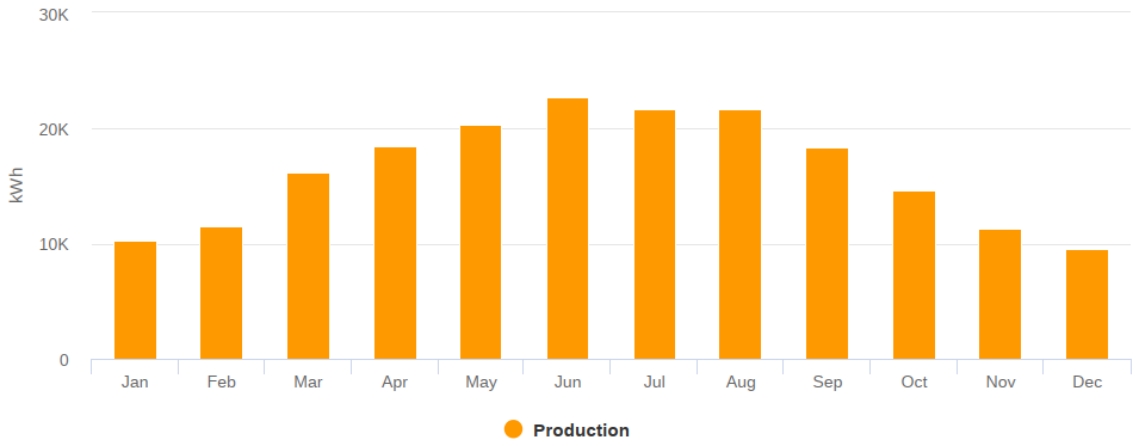


Figure 5. Modeled PV Production



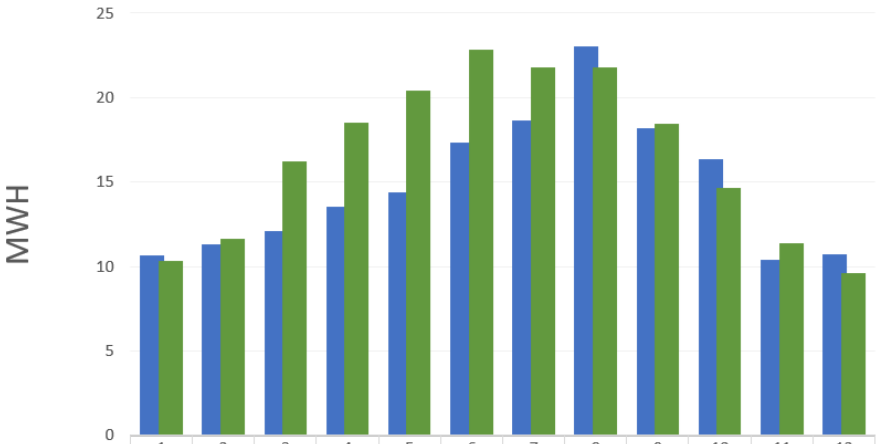
Figure 6. Modeled PV Installation Areas

Modeled PV Production

The modeled PV system is projected to generate an average of **16,383 kWh per month**, with an estimated **annual production of 197,615 kWh**.

This scenario doesn't include a BESS, so the excess energy produced need be exported to the utility, which requires entering a Net Energy Metering (NEM) contract with the utility service provider. Under the currently available NEM tariff, NEM 3.0, exported electricity is credited at dynamic rates that vary by month, hour of day, and weekday, ranging from as low as $0.01/kWh during midday hours to over $1.00/kWh during peak evening hours in high-demand months like August and September. This study has calculated projected benefits from this arrangement.

Figure 8 compares historic monthly energy consumption and modeled PV generation. Not all solar energy will be consumed on-site, as excess daytime production may exceed demand and be exported to the grid, while nighttime demand cannot be covered since there is no generation after sunset and no battery to store the excess in this scenario.



	1	2	3	4	5	6	7	8	9	10	11	12
System Load	11	11	12	14	14	17	19	23	18	16	10	11
PV Generation	10	12	16	19	20	23	22	22	18	15	11	10

Figure 7. Modeled PV Output vs. Site Demand

Capital Expenditures

Based on NLR benchmark CAPEX values for commercial rooftop solar, the estimated cost to install a 108 kW DC PV system in Riverside County, California falls in the range of **$1.75 to $2.00 per watt DC**. This translates to a total investment of **approximately $189,000 – 216,000 for the complete system**.

These figures include **typical equipment, installation, and soft costs**, reflecting average market conditions for commercial-scale projects. Actual costs may vary slightly depending on site-specific conditions such as roof structure, permitting, interconnection requirements, and labor. However, the NLR benchmarks provide a reliable basis for estimating the capital cost of a system of this size and type in the region.

Operating Expenses

According to NLR's 2024 benchmark data, the annual operations and maintenance (OPEX) cost for commercial rooftop PV systems is about **$19 per kW DC**. For a 108 **kW DC system**, this translates to an estimated yearly OPEX of roughly **$2,052** covering routine maintenance, monitoring, and related operational expenses.

Economic Metrics

The analysis shows that installing a PV system at the site under NEM3 provides measurable financial benefits by offsetting both energy and demand charges. Without solar, the facility currently spends about $67,192 annually on utility costs. With the PV system in operation, the energy cost is reduced to approximately $21,607 per year, while the demand cost drops to about $13,329 per year. In addition, the system generates excess electricity during the day that cannot be fully consumed on-site. Under NEM3 rules, this exported energy represents an additional benefit of roughly $3,227 annually.

Taken together, these reductions and export credits bring the facility's total utility bill down to **$34,936 per year**, achieving an **overall savings of about 48%** compared to current expenses

Payback Period and Return on Investment

The financial analysis shows that without PV, the facility spends approximately $67,192 per year on utility costs. With a 108 kW DC PV system installed, the annual cost is reduced to about $34,936, resulting in yearly savings of roughly $32,256. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system is estimated at $216,000, but with the 40 percent ITC direct pay, the net investment is reduced to approximately $129,600. In addition, the system carries an annual OPEX of $2,052, which slightly offsets the yearly savings. Taking these factors into account, the project generates a net benefit of about $32,256 minus $2,052 per year after OPEX. This results in a simple payback period of approximately 5 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross Savings ($)	Net Savings after OPEX ($)	Cumulative Cash Flow ($)
1	32,255	30,203	-99,397
2	33,223	31,109	-68,287
3	34,220	32,043	-36,244
4	35,246	33,004	-3,240
5	36,304	33,994	30,754
6	37,393	35,014	65,768
7	38,515	36,064	101,832
8	39,670	37,146	138,979
9	40,860	38,261	177,239
10	42,086	39,409	216,648
15	48,789	45,685	432,150
20	56,560	52,962	681,976

Table 1. Return on Investment w/ 3% Inflation: Case 1

Technical Feasibility

Based on the electrical single line diagram, the facility is served by a main utility service feeding a main switchboard that distributes power to multiple downstream panels, with an automatic transfer switch connected to an on-site standby generator for emergency loads. Interconnection of an additional 108 kW DC photovoltaic system would occur on the normal power side of the electrical system, upstream of the emergency distribution, to avoid backfeeding the generator or ATS.

The one line indicates that the PV system would require a dedicated backfed breaker or tap connection at the main switchboard or an identified distribution section with sufficient bus rating. Existing main and feeder breaker ampacities must be reviewed to confirm available capacity for the added PV source, and conductor sizes must be verified or upsized if the added current exceeds shown ratings.

Standard PV interconnection equipment is required, including a visible, lockable AC disconnect, inverter output protection, and appropriate grounding consistent with the system ground detail shown on the drawings. The grounding electrode system and bonding connections must be reviewed to ensure compatibility with the inverter grounding requirements.

Protection coordination should be reviewed to confirm that the added PV backfeed does not adversely affect existing breaker settings or fault clearing. Utility interconnection will require compliance with applicable utility requirements, including anti-islanding protection inherent to the inverter and confirmation that the point of interconnection shown on the one line meets utility and code requirements.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 197,615 kWh per year. Using the U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:

- Carbon dioxide (CO_2): 84,614 pounds (lbs) (38.4 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 84,914 lbs (38.5 metric tons) avoided annually
- Nitrogen oxides (NO_x): 65.6 lbs (29.8 kg) avoided annually
- Sulfur dioxide (SO_2): 4.0 lbs (1.8 kg) avoided annually

Case 2: PV + BESS

System Components

This scenario assumes the same PV array described in Case 1 and a BESS sized for surplus PV production. The day with the highest energy surplus in our simulation occurred on May 17, during which the PV system produced 763 kWh, the site consumed 232 kWh, and the resulting surplus was 530 kWh. To size the BESS, we ran several iterations based on the available surplus energy and applied an algorithm that simulates the charge and discharge cycles of one year. This techno-financial analysis indicates that the optimal BESS capacity is approximately 350 kWh.

This simulation factor ensures that even under variations in production or demand, all possible excess solar energy generated during the day can be stored. The stored energy is then available for use at night or during periods when PV production does not fully cover the site's demand.

By doing so, the majority of solar energy produced on-site are consumed daily by the facility, preventing as little as possible any export to the grid.

Modeled Energy Flows

By installing a 350 kWh battery, we ensure that all the energy generated on-site is consumed by the facility itself. The charge and discharge profile of the battery is designed so that any PV surplus during the day is immediately stored in the battery rather than exported to the grid. Later, if the site demand exceeds the PV generation while there is still energy stored in the battery, the deficit is supplied from the battery.

This operational strategy minimizes or even eliminates consumption from the utility, since the PV and battery combination is prioritized to cover the load at all times. On an annual basis, the system is expected to produce slightly more energy than the site requires, leaving a surplus of around 10%, but this excess is negligible in terms of the overall utility bill.

Capital Expenditures

According to NLR benchmark data, the capital expenditure (CAPEX) for a commercial-scale 108 kW DC rooftop PV system in Riverside, California is estimated at $129,600 under ITC incentive, based on installation costs of $1.75–2.00 per watt DC.

For storage, NLR's 2025 cost projections indicate a CAPEX of $450 per kWh for the high-cost scenario. Applying this benchmark to a commercial-scale 350 kWh battery system represents an investment of roughly $122,500 and under the SGIP program this amount can be fully covered, effectively funding 100% of the BESS system

Together, the combined CAPEX for the PV and BESS systems is estimated at 129,600 representing the expected upfront investment for a commercial solar-plus-storage project of this size.

Operating Expenses

According to NLR benchmark data, the annual operations and maintenance (OPEX) cost for a commercial-scale 108 kW DC rooftop PV system is estimated at $2,052.

NLR data indicates an operating cost of approximately $4 per kW-year. For a commercial-scale 350 kWh battery system, this results in an annual OPEX of about $ 1,400.

Together, the combined OPEX for the PV and BESS systems is approximately $ 3,452 per year, covering routine maintenance, monitoring, and system management.

Economic Metrics

The analysis shows that installing a commercial-scale PV system paired with a 350 kWh battery under NEM 3 provides strong financial advantages by allowing a substantial portion of the solar energy produced by the PV system to be consumed on-site.

In several cases, PV production exceeds the facility's demand, and the surplus can be stored in the BESS for later use. However, without a battery system, the facility cannot absorb all of this excess energy, since any unused generation must be consumed the moment it is produced. This unused energy would otherwise need to be exported

to the utility grid, where under current NEM rules it would be compensated at only about 25 percent of the retail electricity rate. Given that time-of-use pricing makes stored energy far more valuable during high-cost periods, it becomes financially preferable to store surplus solar rather than sell it.

Without a BESS, exporting this excess would generate $3,227 but the facility would still face an annual utility cost of $67,192. By contrast, installing the BESS reduces grid reliance and allows the facility to consume nearly all of its solar production during higher-priced periods, resulting in a significantly lower annual utility bill of $6,846

To remain conservative, this analysis assumes that 10% of annual energy costs remain due to efficiency losses, imperfect alignment of PV output and site load, and seasonal variability.

It is important to note that other charges — such as connection fees, requisite charges, and taxes — remain unaffected. This analysis focuses only on those bill components directly impacted by the installation of PV and BESS under the NEM 3 framework.

Payback Period and Return on Investment

The financial analysis shows that without PV + BESS, the facility spends approximately $67,192 per year on utility costs. With a 108 kW DC PV system and 350 kWh BESS system installed, the annual cost is reduced to about $ 6,846 resulting in yearly savings of roughly $60,346. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system under ITC and SGIP incentives is estimated at $129,600. In addition, the system carries an annual OPEX of $ 3,452 Taking these factors into account, the combined system generates a net benefit of about 56,894 per year after OPEX. This results in a simple payback period of approximately 3 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross-Savings ($)	Net-Savings after OPEX ($)	Cumulative Cash Flow ($)
1	60,346	56,894	-72,706
2	62,156	58,601	-14,105
3	64,021	60,359	46,254
4	65,942	62,170	108,423
5	67,920	64,035	172,458
6	69,958	65,956	238,414
7	72,056	67,934	306,348
8	74,218	69,972	376,320
9	76,444	72,072	448,392
10	78,738	74,234	522,626
15	91,279	86,057	928,566
20	105,817	99,764	1,399,163

Table 2. Return on Investment w/ 3% Inflation: Case 2

Technical Feasibility

Based on the single-line on sheet E-2, the service consists of a utility service entrance with metering, a main service section, and multiple distribution feeders labeled 1 through 8 feeding building panels. An emergency power system with an automatic transfer switch (ATS) and generator is shown serving emergency loads. The drawing also includes a system ground detail and a load summary area, indicating this is the principal point of common coupling for the facility.

To interconnect a new 108 kW DC PV system and a 350 kWh BESS, provide a dedicated generation section or a listed PV+BESS combiner that ties at the service side or at the main switchboard section shown adjacent to the service entrance equipment. Select an interconnection point that is upstream of feeder breakers 1–8 so the backfeed does not burden downstream panel buses. The physical location should be coordinated with the “Main Service Elevation” depicted to maintain working clearances and accommodate new breakers or tap cabinets.

If a load-side connection at the main switchboard is chosen, verify bus ratings and available spaces. Provide new backfeed breakers sized for the PV inverter output and the BESS inverter output per the equipment nameplate ratings and the board’s interrupting capacity. Confirm that the sum of main and generation breakers complies with bus rating rules and that the board’s short-circuit rating is adequate with generation sources contributing fault current through the ATS or back to the service.

If the bus rating or space is insufficient, implement a supply-side connection at the service section shown ahead of the main. Use listed service-entrance rated tap hardware or a factory service section to land the PV+BESS feeders. Provide service-rated disconnects that are grouped with the existing service equipment and are accessible to the utility. Coordinate conductor size, tap length, and enclosure ratings with the utility requirements indicated by the metering arrangement on the drawing.

Coordinate protective relaying so that the PV and BESS trip for utility outages and abnormal voltage or frequency. Where an ATS and generator are present, include reverse-power and anti-islanding functions to prevent inadvertent paralleling with the generator through the ATS. Confirm source interlocks so the BESS does not energize the emergency bus when the ATS is on generator or when the utility is absent.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 197,615 kWh per year. Using the U.S. EPA’s Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:

- Carbon dioxide (CO_2): 84,658.3 lbs (38.4 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 84,974.5 lb (38.5 metric tons) avoided annually
- Nitrogen oxides (NO_x): 65.6 lbs (29.8 kg) avoided annually
- Sulfur dioxide (SO_2): 4.0 lbs (1.8 kg) avoided annually

CASE 3: BESS Only

Critical Load Identification

The required emergency load for the Moreno Valley Senior Center is 68.8 kW. This value represents the combined demand of egress illumination circuits mandated under NEC 700, fire alarm system power required by NFPA 72, and limited communication and safety functions considered legally required standby under NEC 701. No other loads in the one-line diagram qualify as emergency or standby obligations for this facility type. Kitchen, office, HVAC, and general receptacles do not meet code requirements for emergency classification and are excluded.

Required Backup Duration

For a Senior Center, maintaining continuous operation of alarm systems, emergency communications, lighting, and fuel dispensing is essential to guarantee mission readiness. According to NFPA 110 (Section 4.2 and 7.12.1), emergency power supply systems (EPSS) must provide a minimum of 2 hours of operation at full rated load. However, because fire stations are classified as critical public safety facilities, most Authorities Having Jurisdiction (AHJs) and best practice guidelines require at least 4 hours of backup capacity to ensure firefighters can respond to emergencies during extended outages.

Battery Capacity & Infrastructure

The battery system rating is sized at 68.8 kW to match the peak emergency demand and 275 kWh to satisfy the 4-hour requirement. These values derive directly from the calculated emergency load and are consistent with emergency-only BESS operation. Integration requires placing the BESS on the load side of the service disconnect, routing output through an ATS, and supplying a dedicated emergency distribution section. Bus and breaker ratings must be reviewed to ensure available fault current compatibility, and the interconnection must maintain clear separation between normal and emergency feeders in accordance with NEC 700 and 701.

Capital Expenditures

Using cost benchmarks published by the National Laboratory of the Rockies (NLR), the estimated capital cost (CAPEX) for a 275 kWh / 50 kW battery energy storage system is approximately $123,750 This figure includes the battery cabinets, inverter/PCS, microgrid controller with ATS, installation, protections, and engineering.

Operating Expenses

The expected operating cost (OPEX) is about $1,100 per year, also based on NLR reference values. This covers preventive maintenance, monitoring software, and NFPA 110 testing requirements. Battery replacement is typically required after 10–12 years of service.

Return on Investment & Qualitative Benefits

While a conventional financial return cannot be directly assigned, a battery system for a Senior Center adds value through resilience, code compliance, and continuity of life-safety functions. It ensures uninterrupted operation of critical circuits during outages and supports NFPA 110, NEC 70, and NFPA 72 requirements. For this site, the justification depends on whether existing backup assets already meet or exceed the emergency load. If a generator is present and sized above the emergency requirement, the additional resilience contribution of the BESS becomes a policy and redundancy decision rather than a strict technical necessity.

Technical Considerations

Integration requires verifying service bus capacity, available fault current, and compliance with the 120-percent rule for any load-side interconnection. Breaker sizing and feeder routing must preserve the separation between normal and emergency circuits. An ATS must serve as the transfer interface between the BESS and the emergency distribution. Short-circuit analysis, selective coordination review, transfer-sequence validation, and UL 9540A safety considerations must be completed prior to installation.

Decision Matrix and Scenario Comparison

In order to determine the most appropriate scenario for the site, four scenarios were developed and analyzed: business as usual (Case 0), installing a PV system only (Case 1), installing PV with a BESS (Case 2), and installing a BESS only (Case 3). Each case was evaluated in terms of resilience value, capital and operating expenditures, energy savings, payback period, and technical feasibility. The decision matrix summarizes the comparative performance of these options.

Criteria	Case 0: Baseline	Case 1: PV Only	Case 2: PV + BESS	Case 3: BESS Only
Resilience Benefit	None	Limited (daytime only)	High (self-consumption, some coverage)	High (but redundant due to existing 125 kW generator)
CAPEX ($)	0	$189k – $216k $129,600 net (after 40% ITC)	PV ($129,600) + BESS (fully covered by SGIP) = Net $129,600	~$123,750, BESS (fully covered by SGIP)
OPEX ($/yr)	Current	~$2,052	~$3,452	~$1,100
Annual Utility Bill ($)	~$67,192	~$34,936	~$6,846	~67,192 (no reduction)
Annual Savings ($)	–	~$32,256	~60,346	Minimal (non-financial)
Payback Period	–	~5 years	~3 years	No ROI
GHG Reduction	None	~38 $MTCO_2e$ avoided annually	Same as Case 1	None
Technical Feasibility	Already in place	Requires breaker adjustment	Requires breaker + storage integration	Technically feasible

Table 3. Scenario Comparison

Conclusion

Based on the comparative analysis, **Case 2 (PV + BESS)** emerges as the preferred scenario for the Moreno Valley Senior Center. While Case 1 (PV only) delivers meaningful utility savings and reduces annual energy costs by approximately 48 percent, the PV-only configuration still leaves the facility exposed to high evening energy prices under the NEM 3 tariff and does not ensure resilience during outages. Case 3 (BESS-only) was dismissed because the battery system alone cannot reduce utility expenditures and provides redundant resilience given the facility's existing generator.

Case 2 delivers the strongest overall value because it allows the site to self-consume nearly all its solar production, storing daytime surplus for use during high-cost evening hours. This configuration reduces the facility's annual utility bill from roughly $67,192 to only **$6,846**, achieving annual savings of more than **$60,000**. When combined with the 40 percent ITC and SGIP Equity incentives, the total project investment is significantly reduced, resulting in a simple payback period of about **three years**, the shortest among all scenarios. Additionally, this scenario delivers full operational resilience by supplying onsite generation and storage capable of supporting the site through grid disruptions.

Therefore, **Case 2 achieves the best balance of resilience benefit, operational savings, capital efficiency, and long-term practicality**. It maximizes economic performance under NEM 3, ensures continuity of essential functions without relying solely on the existing generator, reduces greenhouse gas emissions, and provides the greatest strategic value for the facility over its lifetime.

Summary of Strategy & Benefits

The selected strategy focuses on installing a 108 kW DC rooftop PV system paired with a 350 kWh battery energy storage system. This combined approach enables the Senior Center to maximize onsite solar consumption, reduce reliance on the grid, and achieve near-complete elimination of daytime and evening electricity costs. This strategy provides the following benefits:

- **Resilience:** Provides full energy resilience by enabling the facility to operate through grid outages using stored solar energy. The PV + BESS combination ensures continuity of essential functions without relying solely on the existing generator.
- **Economic Savings:** Reduces annual utility costs from approximately $67,192 to $6,846, enabling yearly savings of about $60,346. These savings continue to grow over the system's lifespan due to rising energy prices.
- **Financial Feasibility:** Delivers a highly favorable payback period of approximately three years, supported by the 40 percent ITC direct-pay credit and the SGIP Equity incentive, which fully covers the BESS cost.
- **Environmental Impact:** Offsets about 38.4 metric tons of CO_2e emissions annually, directly contributing to local and regional climate goals while reducing the facility's dependency on fossil-fuel–based grid electricity.
- **Technical Efficiency:** Maximizes onsite solar consumption by storing daytime surplus for evening use, significantly reducing exposure to NEM 3's low export rates and high peak-period pricing.
- **Operational Practicality:** Provides long-term stability in operating expenses while minimizing energy export, lowering peak demand, and maintaining simple daily operations with automated control of solar and storage assets.

Next Steps

To advance the project, the following steps are recommended:

1. **Detailed Design & Site Assessment:** Conduct a 30% design phase evaluation, including structural assessment of the roof, electrical interconnection details, and shading analysis
2. **Vendor Quotations:** Obtain updated vendor quotes for PV system equipment, installation, and interconnection to refine cost estimates beyond NLR benchmarks
3. **Permitting & Interconnection:** Coordinate with Southern California Edison (SCE) to complete the interconnection study and ensure compliance with NEM 3 tariff rules
4. **Finalize Incentive Applications:** Submit applications for the 40% ITC (direct pay) to secure federal funding and reduce upfront capital cost
5. **Procurement & Installation:** Issue RFPs for procurement and construction, selecting qualified contractors with experience in municipal PV installations
6. **Commissioning & Monitoring:** Upon installation, perform commissioning tests, integrate the system with monitoring platforms, and establish an operations and maintenance (O&M) plan to ensure reliable long-term performance

Appendix

Incentive Programs

This section outlines how the incentive programs function and provides relevant information about them. Specific application of these programs to presented scenarios is explored in previous sections.

Inflation Reduction Act

The Inflation Reduction Act of 2022 stands as a significant piece of legislation designed to strengthen the United States' commitment to fighting climate change by making considerable investments in renewable energy. A key feature of the Inflation Reduction Act is its financial incentives, namely the Investment Tax Credit (ITC) and the Production Tax Credit (PTC), which aim to accelerate the adoption of renewable energy technologies.

The ITC allows for a significant tax credit for investments in renewable energy technologies, including solar panels and wind turbines, directly reducing the upfront cost of these systems. This makes renewable projects more financially viable and attractive to investors and consumers alike. On the other hand, the PTC provides a per-kilowatt-hour tax relief for the production of energy from renewable sources, incentivizing the operation and expansion of renewable energy facilities.

Notably, Inflation Reduction Act programs have been subject to change in recent legislation. Presented here are active opportunities as of the time of the report.

Production Tax Credit

The Production Tax Credit (PTC) within the framework of the Inflation Reduction Act offers considerable financial incentives for renewable energy projects, primarily designed to decrease the federal income tax liability based on the electricity produced per kilowatt-hour.

The PTC directly reduces the federal income tax for taxable entities. Furthermore, for non-taxable entities such as local governments, educational institutions, or nonprofit organizations, the PTC allows these credits to be monetized, facilitating their involvement in renewable energy initiatives. This provision is applicable for projects that become operational between January 1, 2023, and December 31, 2032, providing a broad window for planning and implementation.

Projects located in designated low-income energy communities receive further incentives. The PTC is structured to be claimable annually for a decade from the start date of operations of the qualifying renewable system, providing long-term financial support. This current structure of the PTC is set to continue through the end of 2024. Starting from January 1, 2025, the credit system will transition to a technology-neutral format, broadening the scope to include a wider array of technologies and fostering a more inclusive approach to renewable energy incentives.

As of the date of this report, the program is still active but solar projects must have “begun construction” by July 4, 2026.

The City project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

Investment Tax Credit

The Investment Tax Credit (ITC) established under the Inflation Reduction Act offers a powerful incentive for deploying renewable energy technologies by providing a reduction in federal tax liability. This reduction is calculated as a percentage of the capital investment made in eligible energy systems. Taxpayers can apply the ITC to their federal income tax for the year the technology is installed, significantly decreasing their tax burden.

Starting January 1, 2023, special provisions enable tax-exempt entities such as local governments and nonprofits to receive direct payments equivalent to the value of the credit. This arrangement improves the liquidity and financial feasibility of renewable projects for these organizations. The scope of eligible technologies under the ITC is broad, encompassing solar panels, wind turbines, fuel cells, and other renewable energy systems.

As of 2025, the Investment Tax Credit (ITC) for solar projects is set at 30% of the eligible costs, encompassing both the equipment and installation expenses. This rate is scheduled to decrease to 26% in 2033 and further to 22% in 2034. Systems rated under 1 megawatt (MW) qualify for the full 30% without having to comply with additional requirements; larger systems will only receive the full amount if they meet specific labor requirements. These include paying prevailing wages to workers during construction and using apprentices to perform a portion of the total construction hours (15% after 2023). Bonus credits are available based on site location, e.g. low-income communities.

The ITC is set to continue delivering these benefits at its current rate until 2032, contingent upon meeting the specific project criteria laid out in the act. Looking ahead, post-2024, the ITC will transition to a technology-neutral system, which will be applicable to all zero-emissions technologies, reflecting a shift towards a more inclusive and adaptable approach to supporting renewable energy development.

HHZP project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

As of the date of this report, the program is still active but critical deadlines for project eligibility and complete operability are quickly approaching in 2026 and 2027, respectively.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) offers financial incentives to non-residential customers of utility Company to encourage the adoption of energy storage systems. These systems help businesses prepare for power outages that may occur due to weather, emergencies, or other unforeseen events. The SGIP funding is authorized through 2024, with incentives structured to decrease over time as funding milestones are reached or as more participants enter the program.

Non-residential customers have access to three types of SGIP rebates: General Market, Equity, and Equity Resilience. Furthermore, SGIP incentives are significantly higher for vulnerable or disadvantaged communities through the Equity and Equity Resilience categories.

Incentives are typically paid upfront for residential systems upon project completion and site verification, while nonresidential systems may receive half upfront with the balance paid based on the system's performance over time. Eligibility for SGIP incentives extends to residential, commercial, industrial, agricultural, and municipal customers of specific utilities including Pacific Gas & Electric, Southern California Edison, SoCalGas, San Diego Gas & Electric, and those managed by the Center for Sustainable Energy.

To be eligible for this rebate, a facility must satisfy two conditions: firstly, it must fall under the category of a government agency, educational institution, non-profit organization, or small business. Secondly, it must fulfill at least one of the following requirements: be located in a Disadvantaged Community (DAC), be situated in a census tract where the Median Household Income of the Statewide Median Income or be situated in California Indian Country.

On the other hand, the equity resilience rebate offers a rate, covering a percentage of the cost of an average energy storage system. To qualify for this rebate, a facility must meet certain requirements. Firstly, it must have experienced two or more utility Public Safety Power Shut-offs (PSPS), or it should be located in a Tier 2 or 3 High Fire Threat District (HFTD) and serve customers in DACs or Low Income Communities. Secondly, it must fulfill at least one of the following additional criteria:

- Be a police station, fire station, emergency response provider, emergency operations center, 911 call center, medical facility, private and public natural gas, electric, water, wastewater, or flood facility, jail or prison, utility-designated PSPS assistance center, cooling center, homeless shelter.
- Be a grocery store, supermarket, or corner store with less than $15 million in annual gross receipts.

- Be an Independent Living Center or a Food Bank.

Modeling Assumptions

The modeling conducted for this feasibility study was based on standard industry benchmarks, available site data, and conservative assumptions to ensure realistic projections. The following key assumptions were applied:

1. **Energy Consumption Baseline** – Historical hourly load data (8,760 points) from the facility was consolidated to represent a typical annual profile. This served as the reference for sizing PV and BESS systems.
2. **PV System Costs** – Capital expenditure (CAPEX) and operations and maintenance (OPEX) values were derived from the National Laboratory of the Rockies (NLR) 2024–2025 benchmarks for commercial rooftop systems. PV CAPEX was assumed at $1.75–$2.00/Wdc, with OPEX at ~$19/kW-year.
3. **BESS Costs** – Battery energy storage CAPEX was modeled using NLR 2025 benchmarks at ~$350/kWh. OPEX was assumed at ~$40/kW-year, covering maintenance, monitoring, and lifecycle management.
4. **ITC Incentives** – A 30% Investment Tax Credit (direct pay) was assumed, reducing upfront project cost. No additional low-income or disadvantaged community adders were included, since the site does not qualify.
5. **Performance Parameters** –
    - PV generation modeled with HelioScope using site tilt, azimuth, and shading factors.
    - Battery modeled with 90% round-trip efficiency and daily cycling where applicable.
    - Energy inflation rate of 3% annually applied to utility costs.
6. **Utility Tariff** – The analysis used the most recent Southern California Edison tariff, **TOU-GS-2 Option D**, as published in the file *ELECTRIC_SCHEDULES_TOU-GS-2_2025*. It was assumed under the current **NEM 3** framework. Exported PV energy was valued at ~25% of retail rate. Since tariff structures and prices are subject to future changes, the financial outcomes presented here should be viewed as indicative estimates rather than fixed projections.
7. **Infrastructure** – Electrical interconnection feasibility was preliminarily evaluated using customer-provided single-line diagrams. Minor breaker adjustment (600 A to 500 A) was assumed to comply with NEC 705.12 120% busbar rule for PV backfeed.
8. **Environmental Impact** – Greenhouse gas (GHG) reduction estimates were calculated using EPA eGRID emission factors for the CAMX subregion, applied to modeled PV generation.

Disclaimer: These figures are rough estimates intended for feasibility-level evaluation. If more precise values are required, additional detail must be developed through site-specific engineering, vendor quotations, and utility coordination during the advanced design phase.

Net Energy Metering

Net Energy Metering (NEM) in California is a billing arrangement that allows residential and commercial customers who generate their own electricity, primarily through solar photovoltaic (PV) systems, to receive credit for the surplus energy they contribute to the grid. This system is designed to incentivize the use of renewable energy sources by offsetting the cost of electricity consumption with the energy produced by these installations.

Under NEM, when a solar system generates more electricity than is consumed, the excess energy is sent back to the utility grid, and the customer earns credits. These credits can then be used to offset the cost of energy drawn from the grid when the solar system isn't producing enough to meet the customer's demand, like during nighttime or cloudy days. The rules, rates, and credits under NEM can vary over time, with different iterations such as NEM 1, 2, and the latest NEM 3, each having specific regulations and compensation structures for solar energy production and exchange.

The transition from NEM 2 to NEM 3 in California, which was effective on April 14, 2023, introduced significant changes in the net metering policies for utility customers with photovoltaic (PV) systems. These changes impact

several aspects, particularly the economics of energy arbitrage between PV system owners and the utility. Here's a summary of the key changes:

1) **Reduction in Export Rates:** Under NEM 3, there's a substantial reduction in the rates for excess electricity exported onto the grid by solar systems. This rate has been reduced by approximately 75%, thereby lowering the overall savings for home solar systems and increasing the payback period. This change is a shift from the traditional one-to-one offset of net metering policies, where the price of a kWh of electricity pushed onto the grid was equal to the price of a kWh pulled off the grid.
2) **Implementation of Electrification Rates:** Customers enrolling in NEM 3 are required to use electrification rates instead of regular Time-of-Use (TOU) rates. These electrification rates feature higher on-peak charges and lower off-peak charges, along with a fixed charge of $15 per month. The peak rate period remains from 4 pm to 9 pm.
3) **Export Compensation Based on Avoided Cost Calculator (ACC):** Export compensation under NEM 3 is determined by California's ACC, with specific export rates for every combination of Month, Hour, and Weekday or Weekend. The export value is lowest in the middle of the day when solar energy is abundant on the grid and highest during peak summer demand periods. Notably, the export rates are significantly lower than retail rates during the hours when PV systems are most productive (10 am – 3 pm). To maintain the financial viability of solar PV systems, customers in PG&E and SCE service territories receive an adder on top of the ACC rate, ranging between 2.2 and 9 cents depending on location and customer class.
4) **Shift to a Cost Avoidance System:** NEM 3 introduces a cost avoidance system for exported electricity. This system pays customers the lowest amount a company can pay under the Public Utility Regulatory Policies Act of 1978 (PURPA), which is significantly less than the typical retail rate. This results in customers receiving, on average, 75% less for the electricity they sell back to the grid, with rates varying by month and by hour.
5) **Grandfathering NEM 2 under NEM 3:** Under the recent NEM 3 policy in California, existing customers with a photovoltaic (PV) system installed under NEM 2 can retain the benefits and terms of their NEM 2 agreement, a process known as "grandfathering." However, these customers are restricted from replacing or adding capacity to their PV systems if they wish to maintain their NEM 2 status, as any significant modifications would require transitioning to the terms of NEM 3.

The Net Energy Metering (NEM) 3.0 policy introduces transformative changes, particularly enhancing the value of utilizing Battery Energy Storage Systems (BESS) for owners of solar power systems. A significant aspect of NEM 3.0 is the reduction in compensation rates for surplus electricity fed back into the grid by solar systems, now down to 75%. This adjustment shifts the financial dynamics, making it less lucrative to export excess solar energy to the grid. Instead, storing this surplus energy in a BESS and utilizing it when energy costs are higher becomes a more financially savvy approach.

The utility of BESS extends beyond merely optimizing the use of solar energy. It offers several additional advantages, such as providing backup power during utility blackouts, mitigating charges associated with demand peaks, and enabling energy arbitrage. Energy arbitrage under this system allows for the charging of BESS not only with excess solar energy but also with cheaper grid energy during low-cost periods. This stored energy can then be used in lieu of more expensive grid power at peak times, effectively reducing reliance on utility-supplied energy. Consequently, NEM 3.0 not only promotes more efficient use of solar energy but also broadens the scope of BESS applications, contributing to a more versatile and resilient energy management strategy.

AECOM



Microgrid Feasibility Study
City of Perris

Site:
City of Perris Senior Center
100 North D Street, Perris, CA 92570

February 2026

Delivering a better world

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Executive Summary

This study appraises the viability and benefits of distributed energy resource implementation scenarios at the subject site. Four scenarios were developed and compared, with key performance metrics summarized below:

Case	Components	CAPEX ($)	Utility Savings ($/year)	Annual Utility Bill ($)	Payback Period (years)	GHG Reduction ($MTCO_2e$)
1	PV	~$82k (gross) ~$48.9k net w/ ITC	~40%	~$15,114	~5	~13.5
2	PV + BESS	~$48.9k net (PV + BESS fully incentivized)	~88%	~$3,160	~3	~13.5
3	BESS	~$13.5k (SGIP funded)	—	~$25,192	—	—
0	Business-as-usual	$0	—	~$25,192	—	—

Note: All values are approximate and subject to final design and incentive approval..

- **Case 1: Photovoltaic (PV) array** – Introduces on-site renewable generation and delivers solid financial performance; however, excess solar exports are penalized under NEM 3.0, limiting overall value and resilience.
- **Case 2: PV + battery energy storage system (BESS)** – Maximizes self-consumption of electricity produced from onsite PV array, significantly reduces grid reliance, and provides limited backup capability. The battery system is fully funded through SGIP, resulting in superior economics and the fastest payback.
- **Case 3: BESS only** – Provides emergency resilience benefits but does not reduce annual utility costs and does not deliver a financial return as a standalone investment.
- **Case 0: Business-as-usual** – Maintains full utility dependence with no resilience, cost control, or environmental benefits.

Based on the analysis presented in this study, **Case 2 (PV + BESS)** is identified as the most suitable and cost-effective path forward. This scenario delivers the highest annual savings, the shortest payback period, and improved operational flexibility, while minimizing capital risk through incentive-driven cost recovery. Additionally, a portion of the battery capacity can be allocated to support critical loads during utility outages without materially impacting project economics.

Recommended Next Steps.

1. Advance to a 30% design phase with detailed site and structural assessments
2. Procure vendor-specific quotations to refine cost estimates beyond what is provided in this study
3. Initiate permitting and interconnection applications with Southern California Edison under the current Net Energy Metering tariff (NEM 3.0)
4. Secure federal incentives, specifically the 30% Investment Tax Credit (direct pay), to lower upfront costs
5. Prepare procurement and construction planning, targeting installation within the next budget cycle.

The goal is that with these data-driven microgrid feasibility assessment findings, the City of Perris can make an informed decision regarding an appropriate resilience-improving investment at the subject site.

Background

Purpose

In recent years, especially within the past decade, the impacts of extreme heat and wildfires have been profound through the Inland Empire. Power service disruptions have been increasing in frequency and severity throughout Riverside County, affecting the availability of essential services and community resources.

In 2023, the Western Riverside Council of Governments (WRCOG) received an award (Grant Agreement OPR23145) from the Adaptation Planning Grant Program of the California Governor's Office of Land Use & Climate Innovation Integrated Climate Adaptation and Resilience Program. This program provides funding to help fill local, regional, and tribal planning needs, provides communities the resources to identify climate resilience priorities, and supports the development of a pipeline of climate-resilient infrastructure projects across the state.

As part of this grant-funded project, the Energy Resilience Plan 2.0, WRCOG commissioned microgrid feasibility studies for its member agencies. These studies serve to provide valuation of a potential microgrid at a community-essential facility, as designated by the member agency.

The site selected for the City of Perris is the City of Perris Senior Center located at 100 N D St, Perris, CA 92570.

This study presents key insights and findings from the evaluation of distributed energy resource (DER) scenarios, including photovoltaic (PV) array and battery energy storage system (BESS) components, at the subject site. It includes analysis of the site's historic energy demand profile and appraises potential PV array and BESS sizing and siting scenarios accordingly. Notably, the study includes assessment of the generation and storage requirements to support the site's critical loads to enable resilience for a specified number of hours during power service disruptions.

Furthermore, this study outlines the financial implications of self-generation, including estimated cost savings, return on investment (ROI), and potential financing options for the project.

It is important to note that this study serves as a preliminary technical and financial assessment. Its purpose is to provide the City of Perris with the information to make an informed decision on whether to proceed to next phases of microgrid implementation before committing to detailed engineering design and further investment.

Adaptation Planning Grant Program

As communities in California experience more frequent, prolonged, and severe impacts from climate change, communities and governments at all scales are developing strategies and implementing actions to build a climate-resilient future. However, many jurisdictions, especially under-resourced communities in California, lack the capacity, tools, guidance, and resources to effectively prepare for climate impacts.

The Adaptation Planning Grant Program addresses this capacity gap by providing funding to help fill planning needs, providing communities with the resources to identify climate resilience priorities, and supporting the development of climate resilience projects across the state. The Adaptation Planning Grant Program enables communities to climate risk and adaptation considerations into planning activities and prepare for climate readiness and resilience in the long term.

The Adaptation Planning Grant is part of the Integrated Climate Adaptation and Resiliency Program (ICARP) housed within the Governor's Office of Land Use and Climate Innovation. ICARP advances statewide climate adaptation and resilience by coordinating investments, partnerships, and climate science to ensure people, natural systems, and the built environment are protected, prepared, and thrive in the face of climate change.

Through direct and equity-focused investments and resources, ICARP helps build climate adapted and equitable communities in California, with a focus on solutions that address the impacts of climate change and reduce greenhouse gas emissions. ICARP works to advance these priorities across all levels of government by developing

actionable science and research; providing guidance, tools, and technical assistance; and administering climate resilience-focused grant programs.

Learn more: https://lci.ca.gov/climate/icarp/

Modeling Methodology

This section defines the criteria for sizing the PV array and BESS system components, detailing general parameters, technical requirements, and expected performance criteria.

PV Modeling

1. **Data Inputs**
    - **Solar Resource**: Hourly or sub-hourly irradiance data (e.g., typical meteorological year or on-site measurements)
    - **Site-Specific Factors**: Tilt angle, azimuth, shading analysis, and available roof/ground space
2. **Simulation Approach**
    - Use of HelioScope software to estimate hourly PV production
3. **Sizing Criteria**
    - **Capacity Target**: The sizing criteria are based on 105% of the facility's current annual energy consumption. This approach aims to fully offset the facility's energy usage with the PV array while incorporating an additional 5% capacity to accommodate future demand growth. However, the final system capacity is constrained by the area designated as available by the client.
    - **Performance Ratio**: Evaluate Performance Ratio to ensure consistent system output
    - **Energy Production**: Hourly, daily, monthly, and annual PV generation forecasts
    - **Load Matching**: Amount of PV energy that directly offsets site load vs. excess exported to the grid

BESS Modeling

1. **Data Inputs**
    - **Load Profile**: Detailed electricity consumption and demand patterns
    - **PV Production Profile**: From the PV modeling results
    - **Energy Duration for Resilience**: Determine the critical loads that the BESS will support during islanding operations
2. **Operational Modes**
    - **Energy Shifting / Excess PV Storage**: Battery charges when PV output exceeds site demand, discharges when site demand is high.
    - **Resilience (Standalone BESS)**: Sized to support critical loads during outages
3. **Sizing Criteria**
    - **Capacity (kWh)**: Based on required autonomy (energy shifting, peak shaving, or resilience duration)
    - **Max Discharge/Charge Rate (kW)**: Aligned with site load peaks, PV generation surpluses, and emergency power needs
4. **Simulation Approach**
    - Hourly or sub-hourly dispatch modeling to maximize economic benefit (e.g., demand charge reductions or avoided peak rates)

- Incorporate battery round-trip efficiency, self-discharge, and operational constraints (e.g., partial charge strategies)

5. **Output**

   - **Discharge/Charge Profiles**: Hourly modeling of how the battery is utilized
   - **Cost Savings**: Reduction in energy and demand charges or avoided grid cost
   - **Backup Duration**: If sized for resilience, the total hours/days of critical load coverage

Assumptions

AECOM collected facility data through a request for information process. Energy consumption factors and facility characteristics were identified and integrated in analysis. AECOM used these combined datasets to confirm energy utility consumption baselines.

In performing the analysis, AECOM made the following assumptions:

- This report refers to the City of Perris Senior Center, located at 100 N D St, Perris, CA 92570.
- The monthly and annual electricity consumption is determined using load profile data in the client-provided file "CITY OF PERRIS_700447211571 Interval Data Report_2025." This file contains 35040 load profile data points, which are then consolidated into an 8760 load profile dataset.
- AECOM utilized the Levelized Cost of Energy (LCOE) for the installed cost per watt of PV installations and BESS, as sourced from the National Laboratory of the Rockies (NLR). This data was used to estimate the hypothetical cost of installing the PV array and BESS at the site, as detailed in this report. For an accurate cost estimation, it is necessary to obtain vendor quotes, which are subject to change due to market-dependent time windows. These quotations are typically conducted during the 60% design phase, at which point there is an understanding of the specific equipment ratings and brands to be used.
- This report evaluates the site's existing electrical infrastructure using customer-provided data on the main breaker and bus capacity, as documented in the client-provided file "Senior Center Plans." AECOM has assessed whether the existing electrical system can support the proposed PV array and BESS installation. However, as this is a feasibility study, an on-site assessment is required for a definitive determination. A site visit should be conducted during the advanced design phase, typically at the 30% design stage, to confirm site-specific conditions.
- AECOM has estimated the potential PV generation capacity based on the client-identified available area. No detailed site layout or finalized PV location file was provided; therefore, the proposed PV capacity was selected based on engineering judgment and additional technical criteria. A site assessment is required in later project phases, typically at the 30% design stage, to confirm that the site has the necessary infrastructure for PV array installation. This assessment will include evaluation of civil structures, load-bearing capacity, particularly for rooftop installations, and other critical conditions required for successful implementation.
- The site is known to have an existing PV system installed; however, the customer did not provide sufficient technical or operational data to characterize its capacity, configuration, or current performance. As a result, the existing PV system is acknowledged but not explicitly modeled in this phase. Once adequate data becomes available, a refined analysis may be performed by applying an arithmetic deduction to the proposed PV capacity, subtracting the verified generation capacity of the existing system if it is confirmed to be operational.
- This report uses a regionalized estimate of general production (kWh) to calculate the amount of greenhouse gas emissions avoided through PV generation. The calculation is based on the U.S. EPA Emissions & Generation Resource Integrated Database (eGRID).
- This report clarifies that other charges such as connection fees, required service charges, and taxes remain unchanged. The analysis focuses solely on the bill components directly affected by the installation of PV and BESS under the NEM 3 framework.

AECOM utilized the following tools in conducting the analysis:

- AECOM Internal Tools: Proprietary tools developed by AECOM for analyzing energy patterns and evaluating system performance in simulated environments. These tools are designed to assess energy costs for applications such as peak shaving, energy trading, etc. in DER implementations.
- HelioScope: Web-based software tool used for the design and performance analysis of photovoltaic systems. It combines system layout design with energy simulation, allowing users to model rooftop, ground-mounted, and canopy PV installations. The software factors in module placement, tilt, azimuth, shading, and local weather data to provide accurate estimates of system capacity and expected energy generation.

Site Information

This study is conducted for City of Perris Senior Center, located in 100 N D St, Perris, CA 92570. The Senior Center currently consumes about **65,831 kilowatt-hours (kWh) per year**,

Based on the reviewed electrical drawings, the site is served by an existing Main Switch Gear (MS / MSB) rated at 400 amperes (A), 120/240 volts (V), and single-phase (1Ø). An existing exterior 400 A switchboard feeds the facility, from which a new feeder is derived through a new 150 A, 2-pole circuit breaker installed within the existing switchboard.

The primary electrical expansion shown in the drawings is a new “Panel A” serving the Assembly Room. The one-line diagram labels Panel A as 100 A, 120/240 V (with a note indicating “3Ø”), while the panel schedule indicates 120/240 V, single-phase, 3-wire configuration with a 150 A bus and a 150 A main breaker (2P), surface-mounted. This discrepancy between the one-line diagram and the panel schedule (three-phase versus single-phase) should be verified in the field to confirm the actual configuration.

The panel schedule indicates a total connected load of approximately 20,548 watts (W) on Panel A. In addition, the “Load Calculation – Main Switchboard MS” sheet references a peak utility demand recorded by SCE of 30 kW (October 2015), a calculated demand of 37.5 kVA (125% of 30 kW), and a new Panel A load of 95 kilovolt-amperes (kVA). The resulting calculated feeder load at the existing main switchboard MS is shown as 251.25 kVA, corresponding to a calculated current of approximately 251 A at 120/240 V, single-phase.

The new feeder to Panel A is indicated as two 1/0 AWG conductors in a 2-inch conduit with a #6 grounding conductor. The interrupting capacity (kAIC) of the main switchboard and downstream equipment is not explicitly stated in the provided drawings and should be confirmed to ensure compliance with NEC available fault current requirements.

A photovoltaic system is shown on the second sheet under “Senior Center Solar Carports,” consisting of approximately 198 Sharp ND-208U1 modules (196 active, 2 spares). The system has an equivalent CEC DC capacity of approximately 35.9 kW direct current (dc) and an alternating current (AC) output of approximately 34.3 kW AC based on inverter efficiency. The PV system is interconnected to the main switchboard through an AC disconnect and metering/monitoring equipment. While an existing PV installation is clearly present, AECOM does not currently have sufficient operational and performance data (such as measured production, hourly generation profiles, control configuration, and operational constraints) to reliably integrate this PV system into the resilience or energy analysis portion of the report.



Figure 1. Site Location

Incentive Programs

AECOM has identified three key incentive programs that could benefit the subject site, focusing on renewable energy production and advanced energy storage systems.

The Investment Tax Credit (ITC) and Production Tax Credit (PTC) are federal incentives that reduce the cost of renewable energy projects. ITC offers a tax credit based on a percentage of upfront investment costs, while PTC provides a per-kilowatt-hour credit for electricity generated over time.

Production Tax Credit

Under this initiative, the project is eligible for a tax credit ranging from 0.3 cents to 1.5 cents per installed kWh. The specific value of the credit is determined by several factors, including the project's adherence to certain requirements such as complying with labor standards and using domestic materials.

The PTC program pays for each kilowatt-hour produced over a 10-year period, with government entities receiving the benefit as direct pay instead of a tax credit. For this project, with an estimated 69,338 kWh per year, the best case at 1.5 ¢/kWh would yield about $1,040 annually, totaling around $10,400 over 10 years.

Investment Tax Credit

The City may utilize either the ITC or the PTC, but not both. Because the project has not yet begun construction, the ITC remains the preferred alternative. In this scenario, the project is assumed to be located within a qualifying low-income census tract, enabling eligibility for the additional 10 percent bonus credit.

Under the Low-Income Communities Bonus Credit Program, projects located within a designated low-income community, as defined by the 2016–2020 census tract boundaries in Figure 3, receive an additional 10 percentage points added to the base ITC. This increases the total credit from 30 percent to 40 percent of the eligible project cost.

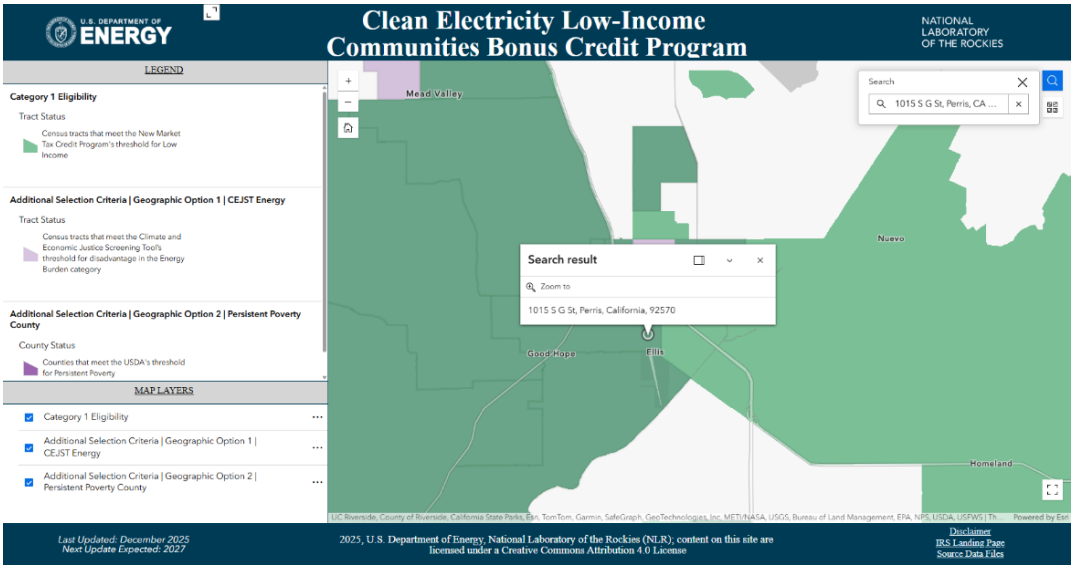


Figure 2. Clean Electricity Low-Income Communities Bonus Credit Program Map

Using NLR's CAPEX range of $1.75–2.00/W DC, the proposed 40.8 kW DC PV system would cost between $71,400 and $81,600. With a 40 percent ITC, the resulting direct-pay benefit increases to $28,560 - 32,640, reducing the project's upfront capital requirements accordingly.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) is California's primary incentive designed to reduce the upfront cost of energy storage systems. The program has three levels:

- **General Market:** For projects located outside Disadvantaged Communities (DAC). Typical incentive: $0.10/Wh.
- **Equity (DAC):** For projects located within a DAC. Incentive: $0.85/Wh.
- **Equity Resilience:** For critical facilities within a DAC and in PSPS or high fire-risk zones. Incentive: $1.00/Wh.

In Case 2, the project is located within a DAC, so it qualifies for the Equity level. Using an NLR-based cost of $450 D/kWh, the 150-kWh battery would cost approximately $67,500. At the Equity incentive rate of $0.85/Wh, the available support would total $127,500, which is sufficient to fully cover the system cost within SGIP's allowable limits.

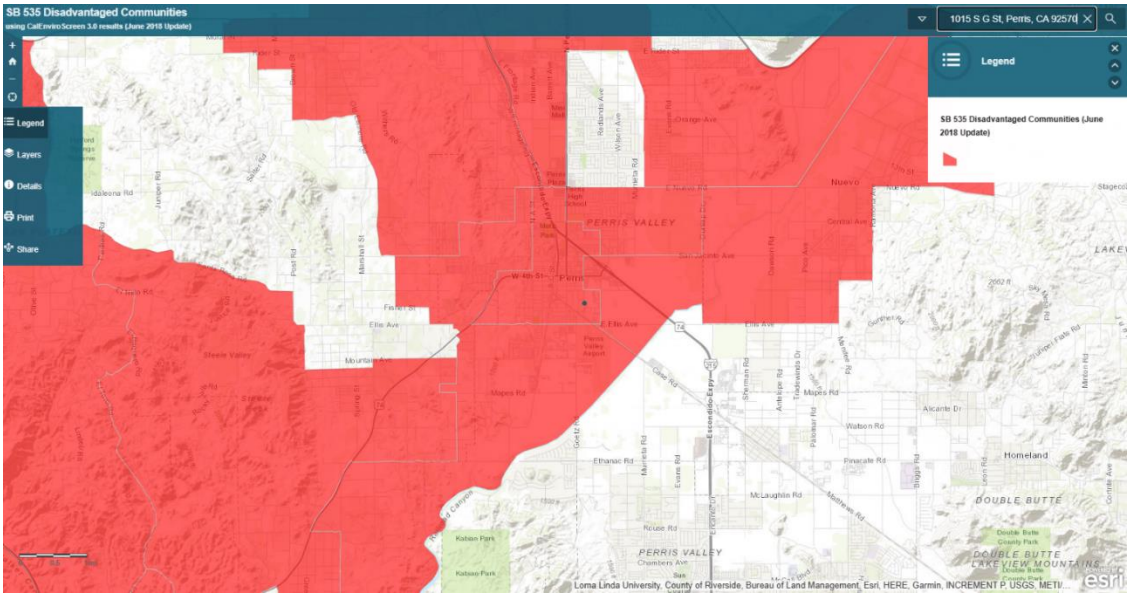


Figure 3. SB 535 Disadvantaged Communities Map

Scenarios & Analysis

Case 0: Current Situation (Baseline)

Tariff & Contract Type

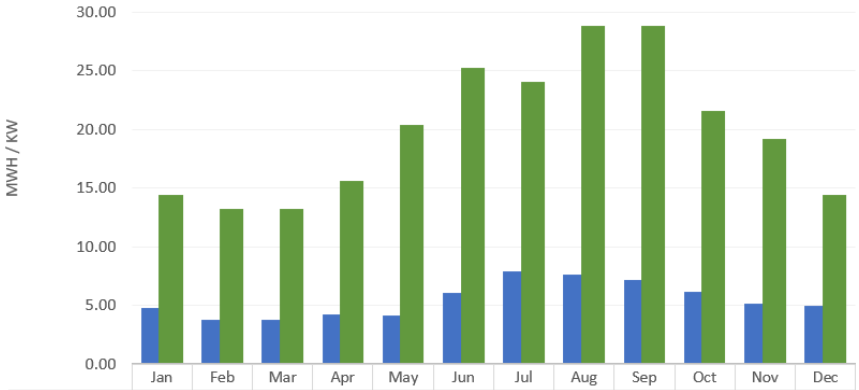
The site is currently served by Southern California Edison under the TOU-GS-2-D CPP tariff, which is designed for small to medium commercial customers. This rate structure separates costs into energy charges (based on kilowatt-hours consumed) and demand charges (based on the highest kilowatt demand registered during the billing cycle). In addition, prices vary by time-of-use periods—on-peak, mid-peak, and off-peak—so the timing of energy use significantly affects overall costs.

Being on this tariff means the site's operating expenses are directly tied not only to how much energy is consumed but also to when it is consumed and how high the peak demand reaches.

The tariff cost presents the costs as totals (delivery + bundle). The prices were used as the basis for this study. While they may fluctuate slightly month to month depending on market conditions, these variations are generally minor.

Monthly & Annual Energy Consumption and Demand

The facility currently consumes 65,831 kWh annually, with August being the highest month at about 7,610 kWh and February the lowest at about 3,810 kWh. In terms of demand, August records the peak at around 28.8 kW, while February is the lowest at about 13.2 kW. The following graph presents this historical data for the 2024–2025 period.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Energy (MWh)	4.76	3.78	3.81	4.26	4.14	6.09	7.91	7.61	7.18	6.16	5.18	4.96
Demand (kW)	14.40	13.20	13.20	15.60	20.40	25.20	24.00	28.80	28.80	21.60	19.20	14.40

Figure 4. Historic Site Energy Profile

Monthly & Annual Energy Costs

The site currently spends about $25,192 per year in energy and demand cost, with approximately $18,006 in energy costs and $9,968 in demand charges, based on tariff TOU-GS-2-D CPP simulation. For this analysis, we are focusing only on energy and demand costs, as these are the components directly impacted by the installation of a PV system.

Case 1: PV Only

Installed Capacity & Location

The existing PV array onsite has been neglected in this Case 1 scenario in favor a newly modeled system, given the lack of information available about the existing solar carport. This modeled PV system was sized to offset approximately 105% of current consumption, with the goal of fully offsetting present usage while reserving about 5% additional capacity for future growth. The placement areas for the PV installation were identified according to customer requirements. The system capacity is estimated at 40.8 kW DC, with an expected annual production of about 69,338 kWh.

Figure 6 presented the modeled energy production throughout the year, and Figure 7 identifies the designated PV installation areas on the site.

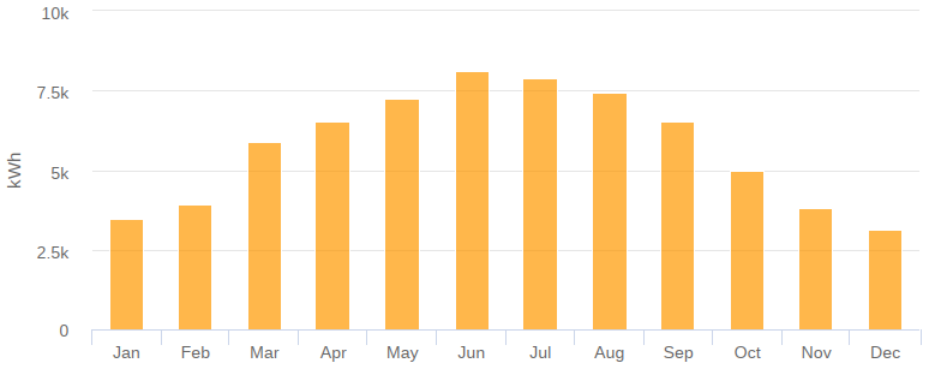


Figure 5. Modeled PV Production



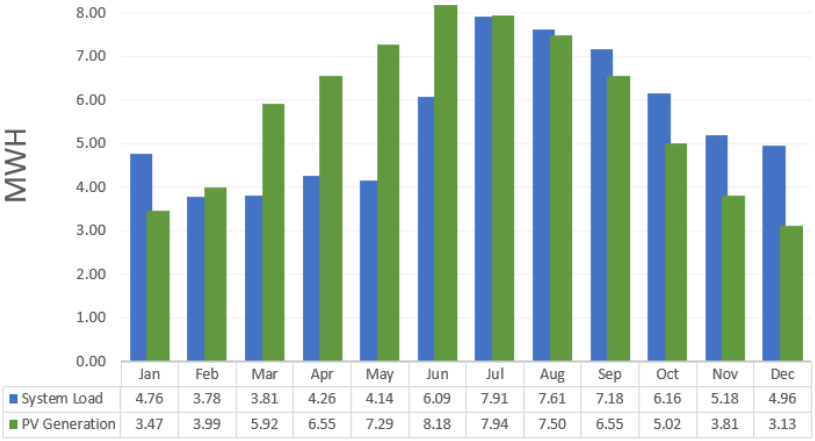
Figure 6. Modeled PV Installation Areas

Modeled PV Production

The modeled PV system is projected to generate an average of **5,778 kWh per month**, with an estimated **annual production of 69,338 kWh**.

This scenario doesn't include a BESS, so the excess energy produced need be exported to the utility, which requires entering a Net Energy Metering (NEM) contract with the utility service provider. Under the currently available NEM tariff, NEM 3.0, exported electricity is credited at dynamic rates that vary by month, hour of day, and weekday, ranging from as low as $0.01/kWh during midday hours to over $1.00/kWh during peak evening hours in high-demand months like August and September. This study has calculated projected benefits from this arrangement.

Figure 8 compares historic monthly energy consumption and modeled PV generation. Not all solar energy will be consumed on-site, as excess daytime production may exceed demand and be exported to the grid, while nighttime demand cannot be covered since there is no generation after sunset and no battery to store the excess in this scenario.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
System Load	4.76	3.78	3.81	4.26	4.14	6.09	7.91	7.61	7.18	6.16	5.18	4.96
PV Generation	3.47	3.99	5.92	6.55	7.29	8.18	7.94	7.50	6.55	5.02	3.81	3.13

Figure 7. Modeled PV Output vs. Site Demand

Capital Expenditures

Based on NLR benchmark CAPEX values for commercial rooftop solar, the estimated cost to install a 40.8 kW DC PV system in Riverside County, California falls in the range of $1.75 to $2.00 per watt DC. This translates to a total investment of **approximately $71,400 - $81,600 for the complete system**.

These figures include typical equipment, installation, and soft costs, reflecting average market conditions for commercial-scale projects. Actual costs may vary slightly depending on site-specific conditions such as roof structure, permitting, interconnection requirements, and labor. However, the NLR benchmarks provide a reliable basis for estimating the capital cost of a system of this size and type in the region.

Operating Expenses

According to NLR's 2024 benchmark data, the annual operations and maintenance (OPEX) cost for commercial rooftop PV systems is about $19 per kW-DC. For a 40.8 kW DC system, this translates to an **estimated yearly OPEX** of roughly **$775**, covering routine maintenance, monitoring, and related operational expenses.

Economic Metrics

The analysis shows that installing a PV system at the site under NEM3 provides measurable financial benefits by offsetting both energy and demand charges. Without solar, the facility currently spends about $25,192 annually on utility costs. With the PV system in operation, the energy cost is reduced to approximately $10,978 per year, while the demand cost drops to about $5,588 per year. In addition, the system generates excess electricity during the day that cannot be fully consumed on-site. Under NEM3 rules, this exported energy represents an additional benefit of roughly $1,453 annually.

Taken together, these reductions and export credits bring the facility's total utility bill down to **$15,114 per year**, achieving an **overall savings of about 40%** compared to current expenses

Payback Period and Return on Investment

The financial analysis shows that without PV, the facility spends approximately $25,192 per year on utility costs. With a 40.8 kW DC PV system installed, the annual cost is reduced to about $15,114, resulting in yearly savings of roughly $10,078. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system is estimated at $81,600, but with the 40 percent ITC direct pay, the net investment is reduced to approximately $48,960. In addition, the system carries an annual OPEX of $775, which slightly offsets the yearly savings. Taking these factors into account, the project generates a net benefit of about $10,078 minus $775 per year after OPEX. This results in a simple payback period of approximately 5 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross Savings ($)	Net Savings after OPEX ($)	Cumulative Cash Flow ($)
1	10,078	9,303	-39,657
2	10,381	9,582	-30,074
3	10,692	9,870	-20,205
4	11,013	10,166	-10,039
5	11,343	10,471	432
6	11,683	10,785	11,217
7	12,034	11,109	22,326
8	12,395	11,442	33,768
9	12,767	11,785	45,553
10	13,150	12,139	57,691
15	15,244	14,072	124,070
20	17,672	16,313	201,022

Table 1. Return on Investment w/ 3% Inflation: Case 1

Technical Feasibility

The facility electrical service is 120/240 V, single-phase, and is supplied by a building main switchgear with a 400 A rating. An existing PV system is installed on the site; however, the client did not provide sufficient inverter nameplate data, interconnection details, as-built documentation, or production and metering records to validate capacity and operational status, therefore this report excludes the existing PV system from technical, load, and energy analyses.

The proposed PV system capacity is 40.8 Kw DC and is served by a 36 kW AC, 240 V AC, single-phase inverter system. The maximum PV AC output current is 36,000 W / 240 V = 150 A. As a continuous source, the minimum required PV output circuit ampacity and overcurrent protection is 150 A × 125% = 187.5 A, which requires a 200 A PV interconnection breaker or fused disconnect rating.

Per NEC 705 bus loading, the allowable backfeed current using the 120% rule is (1.20 × 400 A) minus the 400 A main overcurrent device, yielding 480 A − 400 A = 80 A maximum permitted PV backfeed at the load-side connection. The required PV interconnection overcurrent device is 200 A; therefore, the load-side interconnection is noncompliant by 200 A − 80 A = 120 A.

Corrective actions shall be implemented to resolve the quantified 120 A shortfall. Acceptable remedies include: (1) provide a supply-side connection ahead of the 400 A main overcurrent device in accordance with NEC 705 supply-side connection requirements, with a dedicated 200 A PV service-rated disconnecting means; (2) upgrade the main switchgear bus rating to a minimum of (400 A + 200 A)/1.20 = 500 A (next standard bus rating 600 A) to support a 200 A backfeed while retaining a 400 A main; or (3) reduce the main overcurrent device to a maximum of 280 A so that 1.20 × 400 A − 280 A = 200 A allowable backfeed, provided the calculated service load supports the reduced main rating.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 69,338 kWh per year. Using the U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:

- Carbon dioxide (CO_2): 29,704.4 pounds (lbs) (13.47 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 29,815.3 lbs (13.52 metric tons) avoided annually
- Nitrogen oxides (NO_x): 23.02 lbs (10.44 kg) avoided annually
- Sulfur dioxide (SO_2): 1.39 lbs (0.63 kg) avoided annually

Case 2: PV + BESS

System Components

This scenario assumes the same PV array described in Case 1 and a BESS sized for surplus PV production. The day with the highest energy surplus in our simulation occurred on May 18, during which the PV system produced 269.33 kWh, the site consumed 67.20 kWh, and the resulting surplus was 202 kWh. For size the BESS, we ran several iterations based on the available surplus energy and applied an algorithm that simulates the charge and discharge cycles of one year. This techno-financial analysis indicates that the optimal BESS capacity is approximately 350 kWh.

This simulation factor ensures that even under variations in production or demand, all possible excess solar energy generated during the day can be stored. The stored energy is then available for use at night or during periods when PV production does not fully cover the site's demand.

By doing so, most of the units of solar energy produced on-site are consumed daily by the facility, preventing as little as possible any export to the grid.

Modeled Energy Flows

By installing a 150 kWh battery, we ensure that all the energy generated on-site is consumed by the facility itself. The charge and discharge profile of the battery is designed so that any PV surplus during the day is immediately stored in the battery rather than exported to the grid. Later, if the site demand exceeds the PV generation while there is still energy stored in the battery, the deficit is supplied from the battery.

This operational strategy minimizes or even eliminates consumption from the utility, since the PV and battery combination is prioritized to cover the load at all times. On an annual basis, the system is expected to produce slightly more energy than the site requires, leaving a surplus of around 10%, but this excess is negligible in terms of the overall utility bill.

Capital Expenditures

According to NLR benchmark data, the capital expenditure (CAPEX) for a commercial-scale 40.8 kW DC rooftop PV system in Riverside, California is estimated at $48,960 under ITC incentive, based on installation costs of $1.75–2.00 per watt DC.

For storage, NLR's 2025 cost projections indicate a CAPEX of $450 per kWh for the high-cost scenario. Applying this benchmark to a commercial-scale 150 kWh battery system represents an investment of roughly $27,000 and under the SGIP program this amount can be fully covered, effectively funding 100% of the BESS system

Together, the combined CAPEX for the PV and BESS systems is estimated at 48,960 representing the expected upfront investment for a commercial solar-plus-storage project of this size.

Operating Expenses

According to NLR benchmark data, the annual operations and maintenance (OPEX) cost for a commercial-scale 40.8 kW DC rooftop PV system is estimated at $775.

NLR data indicates an operating cost of approximately $4 per kW-year. For a commercial-scale 150 kWh battery system, this results in an annual OPEX of about $240.

Together, the **combined OPEX for the PV and BESS** systems is approximately **$1,015 per year**, covering routine maintenance, monitoring, and system management.

Economic Metrics

The analysis shows that installing a commercial-scale PV system paired with a 150 kWh battery under NEM 3 provides strong financial advantages by allowing a substantial portion of the solar energy produced by the PV system to be consumed on-site.

In several cases, PV production exceeds the facility's demand, and the surplus can be stored in the BESS for later use. However, without a battery system, the facility cannot absorb all of this excess energy, since any unused generation must be consumed the moment it is produced. This unused energy would otherwise need to be exported

to the utility grid, where under current NEM rules it would be compensated at only about 25 percent of the retail electricity rate. Given that time-of-use pricing makes stored energy far more valuable during high-cost periods, it becomes financially preferable to store surplus solar rather than sell it.

Without a BESS, exporting this excess would generate $1,453 but the facility would still face an annual utility cost of $15,114 By contrast, installing the BESS reduces grid reliance and allows the facility to consume nearly all of its solar production during higher-priced periods, resulting in a significantly lower annual utility bill of $3,160.

To remain conservative, this analysis assumes that 10% of annual energy costs remain due to efficiency losses, imperfect alignment of PV output and site load, and seasonal variability.

It is important to note that other charges—such as connection fees, requisite charges, and taxes—remain unaffected. This analysis focuses only on those bill components directly impacted by the installation of PV and BESS under the NEM 3 framework.

Payback Period and Return on Investment

The financial analysis shows that without PV + BESS, the facility spends approximately $25,192 per year on utility costs. With a 40.8 kW DC PV system and 150 kWh BESS system installed, the annual cost is reduced to about $ 3,160 resulting in yearly savings of roughly $22,032. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system under ITC and SGIP incentives is estimated at $48,960. In addition, the system carries an annual OPEX of $ 1,015 Taking these factors into account, the combined system generates a net benefit of about 21,017 per year after OPEX. This results in a simple payback period of approximately 3 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross-Savings ($)	Net-Savings after OPEX ($)	Cumulative Cash Flow ($)
1	22,032	21,017	-27,943
2	22,693	21,647	-6,296
3	23,374	22,297	16,001
4	24,075	22,966	38,967
5	24,797	23,655	62,622
6	25,541	24,364	86,986
7	26,307	25,095	112,081
8	27,096	25,848	137,929
9	27,909	26,624	164,553
10	28,747	27,422	191,975
15	33,325	31,790	341,932
20	38,633	36,853	515,772

Table 2. Return on Investment w/ 3% Inflation: Case 2

Technical Feasibility

The service is centered on a building main switchgear labeled “MSB” rated 400 A at 120/240 V, 1-phase, with an existing customer generation metering section and generation conductors landed at the MSB through CTs per phase.

An existing solar PV system is shown as a solar carport array feeding an SMA Sunny Tower ST36, 36 kW AC inverter with 240 V AC output. The one-line also shows SCE-required generation metering and two visible, lockable disconnecting means, including an AC disconnect labeled 200 A, 600 V with 200 A fuses, and a Square D fused disconnect labeled 200 A (H364RB) in the interconnection path.

For this report, the existing PV system is treated as an existing condition only. The client did not provide sufficient supporting information to integrate that existing PV into the new PV plus BESS interconnection evaluation, so it is excluded from the project case sizing and compliance calculations.

The additional PV system rated 40.8 kW DC corresponds to approximately 170 A at 240 V AC, 1-phase (30 kW AC ÷ 240 V). The PV output circuit is therefore expected to require a dedicated overcurrent device and disconnecting means sized on a continuous-duty basis, typically resulting in a 225 A class interconnection device for the PV output.

A BESS of 150kWh / 20 kW requires a defined PCS (kW) and AC output voltage to size its interconnection breaker, conductors, and protective functions. The one-line does not provide BESS PCS ratings, so the required BESS breaker and feeder ampacity cannot be finalized from the available information and must be established in design prior to protection coordination and utility interconnection review.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 69,338 kWh per year. Using the U.S. EPA’s Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:

- Carbon dioxide (CO_2): 29,704.4 lbs (13.47 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 29,815.3 lbs (13.52 metric tons) avoided annually
- Nitrogen oxides (NO_x): 23.02 lbs (10.44 kg) avoided annually
- Sulfur dioxide (SO_2): 1.39 lbs (0.63 kg) avoided annually

CASE 3: BESS Only

Critical Load Identification

Based on the facility classification as a community center, the only loads required to receive emergency or legally required standby power are those associated with life safety and code-mandated functions. These include egress illumination, exit signage, and the fire alarm and notification system in accordance with NEC 700 and NFPA 72, as well as any legally required standby lighting per NEC 701. No other building loads are mandated by code to be classified as emergency for this facility type. Using these criteria, the critical load is estimated at 7.5 kW, representing approximately 25 percent of the total connected load. A photovoltaic system is shown on the drawings; however, insufficient information was provided regarding its capacity, interconnection point, and operational mode, and therefore it is acknowledged as existing but excluded from this analysis.

Required Backup Duration

For the Community Center, maintaining continuous operation of alarm systems, emergency communications, lighting, and fuel dispensing is essential to guarantee mission readiness. According to NFPA 110 (Section 4.2 and 7.12.1), emergency power supply systems (EPSS) must provide a minimum of 2 hours of operation at full rated load. However, for critical public safety facilities, most Authorities Having Jurisdiction (AHJs) and best practice guidelines require at least 4 hours of backup capacity to ensure firefighters can respond to emergencies during extended outages.

Battery Capacity & Infrastructure

The battery energy storage system is sized directly from the critical load and required duration. An emergency power demand of 7.5 kW over 4 hours results in a required usable energy capacity of 30 kWh. The BESS power rating is set equal to the critical load to ensure full support of all emergency circuits during an outage. Integration will require connection on the emergency distribution side of the system, downstream of the normal-to-emergency transfer equipment, with dedicated overcurrent protection. The one-line indicates standard panelboard-based distribution, so emergency feeders, breaker spaces, and bus ratings must be verified to accommodate the additional source.

Capital Expenditures

Using cost benchmarks published by the National Laboratory of the Rockies (NLR), the estimated capital cost (CAPEX) for a 30 kWh / 7.5 kW battery energy storage system is approximately $13,500. Under the Self-Generation Incentive Program (SGIP), this cost can be covered at up to 100%. The estimate includes battery cabinets, inverter or power conversion system (PCS), microgrid controller with automatic transfer switch (ATS), installation, protection equipment, and engineering.

Operating Expenses

The expected OPEX is about $120 per year, also based on NLR reference values. This covers preventive maintenance, monitoring software, and NFPA 110 testing requirements. Battery replacement is typically required after 10–12 years of service.

Return on Investment & Qualitative Benefits

While a conventional financial return cannot be directly applied to this case, the value of a BESS for a community center is framed in terms of resilience, reliability, and compliance. Such systems ensure uninterrupted operation of life-safety systems during extended utility outages, supporting safe progress and continuous fire alarm functionality in accordance with NFPA 110, NFPA 70, and NFPA 72. However, if existing backup generation already meets or exceeds the identified 7.5 kW critical load, the incremental benefit of adding a BESS is primarily additional redundancy and operational resilience rather than a strict technical necessity.

Technical Considerations

Key integration considerations include verification of available bus capacity for load-side interconnection, compliance with the 120 percent rule where applicable, and confirmation that breakers and feeders serving emergency circuits are correctly segregated from normal power. Proper coordination of the automatic transfer sequence between utility, existing backup sources, and the BESS is required. A short-circuit and coordination study should be updated to reflect the new source, and fire and safety compliance must address energy storage requirements, including equipment listing and UL 9540A-related considerations consistent with the system size and placement.

Decision Matrix and Scenario Comparison

In order to determine the most appropriate scenario for the site, four scenarios were developed and analyzed: business as usual (Case 0), installing a PV system only (Case 1), installing PV with a BESS (Case 2), and installing a BESS only (Case 3). Each case was evaluated in terms of resilience value, capital and operating expenditures, energy savings, payback period, and technical feasibility. The decision matrix summarizes the comparative performance of these options.

Criteria	Case 0: Baseline	Case 1: PV Only	Case 2: PV + BESS	Case 3: BESS Only
Resilience Benefit	None	Limited (daytime only)	High (load coverage, peak shaving, limited outage support)	Moderate (emergency loads only, redundant if existing generator meets demand)
CAPEX ($)	Current $24k	~$71k–$82k (before ITC) ~$48.9k net w/ 40% ITC	~$48.9k net (PV + BESS fully funded via ITC + SGIP)	~$13.5k (fully covered by SGIP)
OPEX ($/yr)	Current	~$775	~$1,015	~$120
Annual Utility Bill ($)	~$25,192	~$15,114	~$3,160	~$25,192 (no reduction)
Annual Savings ($)	–	~$10,078	~$22,032	Minimal (non-financial)
Payback Period	–	~5 years	~3 years	No ROI
GHG Reduction	None	~13.5 $MTCO_2e$ avoided annually	Same as Case 1	None
Technical Feasibility	Already in place	Feasible with NEC 705 noncompliance mitigation required	Feasible with additional interconnection and storage integration requirements	Technically feasible

Table 3. Scenario Comparison

Conclusion

Based on the comparative analysis, **Case 2 (PV + BESS)** emerges as the preferred scenario for the site. This option delivers the highest overall value by combining rapid financial returns, significant operational cost reduction, and enhanced resilience, while leveraging available incentive programs to minimize upfront capital exposure. Under this scenario, the battery system is fully funded through SGIP incentives, effectively eliminating BESS capital cost and allowing the project economics to be driven primarily by the PV system performance.

Compared to Case 1 (PV only), Case 2 substantially increases annual utility cost savings by maximizing on site solar self-consumption and minimizing low value energy exports under NEM 3. The addition of storage enables excess daytime PV production to be shifted to high value evening and peak periods, reducing annual utility costs to a minimal residual level. Case 3 (BESS only) does not provide a meaningful financial return and is justified only from a resilience or compliance perspective, making it less favorable as a standalone solution.

Therefore, Case 2 represents the optimal balance between economic performance, resilience enhancement, and technical feasibility. The project achieves a simple payback of approximately 3 years, delivers the largest cumulative cash flow over the system life, and improves operational flexibility. In addition, a portion of the BESS capacity can be allocated to support critical loads during utility outages, providing backup functionality without materially impacting the financial performance of the system.

Summary of Strategy & Benefits

The selected strategy focuses on deploying a PV system sized to offset approximately 105 percent of the facility's annual energy consumption, paired with a battery energy storage system funded through available incentives. This integrated approach achieves the following benefits:

- **Resilience**: Battery storage enables limited backup support for critical loads and enhances operational continuity during utility outages.
- **Economic Savings**: Reduces annual utility costs from approximately $25,192 to about $3,160, representing an overall reduction of nearly 90 percent.
- **Financial Feasibility**: Delivers a rapid simple payback of approximately 3 years, driven by high annual savings and fully incentivized battery capital cost.
- **Operational Flexibility**: Allows excess PV generation to be stored and dispatched during high cost periods, minimizing exposure to unfavorable NEM 3 export rates.
- **Environmental Impact**: Offsets approximately 13.5 metric tons of CO_2e emissions annually through on site renewable energy generation.
- **Technical Practicality**: Requires manageable interconnection upgrades and storage integration while remaining compliant with NEC 705 requirements.
- **Long Term Stability**: Provides predictable and inflation resilient energy cost reductions over the remaining service life of the PV and BESS systems.

Next Steps

To advance the project, the following steps are recommended:

1. **Detailed Design & Site Assessment:** Conduct a 30% design phase evaluation, including structural assessment of the roof, electrical interconnection details, and shading analysis
2. **Vendor Quotations:** Obtain updated vendor quotes for PV system equipment, installation, and interconnection to refine cost estimates beyond NLR benchmarks
3. **Permitting & Interconnection:** Coordinate with Southern California Edison (SCE) to complete the interconnection study and ensure compliance with NEM 3 tariff rules
4. **Finalize Incentive Applications:** Submit applications for the 30% ITC (direct pay) to secure federal funding and reduce upfront capital cost
5. **Procurement & Installation:** Issue RFPs for procurement and construction, selecting qualified contractors with experience in municipal PV installations
6. **Commissioning & Monitoring:** Upon installation, perform commissioning tests, integrate the system with monitoring platforms, and establish an operations and maintenance (O&M) plan to ensure reliable long-term performance

Appendix

Incentive Programs

This section outlines how the incentive programs function and provides relevant information about them. Specific application of these programs to presented scenarios is explored in previous sections.

Inflation Reduction Act

The Inflation Reduction Act of 2022 stands as a significant piece of legislation designed to strengthen the United States' commitment to fighting climate change by making considerable investments in renewable energy. A key feature of the Inflation Reduction Act is its financial incentives, namely the Investment Tax Credit (ITC) and the Production Tax Credit (PTC), which aim to accelerate the adoption of renewable energy technologies.

The ITC allows for a significant tax credit for investments in renewable energy technologies, including solar panels and wind turbines, directly reducing the upfront cost of these systems. This makes renewable projects more financially viable and attractive to investors and consumers alike. On the other hand, the PTC provides a per-kilowatt-hour tax relief for the production of energy from renewable sources, incentivizing the operation and expansion of renewable energy facilities.

Notably, Inflation Reduction Act programs have been subject to change in recent legislation. Presented here are active opportunities as of the time of the report.

Production Tax Credit

The Production Tax Credit (PTC) within the framework of the Inflation Reduction Act offers considerable financial incentives for renewable energy projects, primarily designed to decrease the federal income tax liability based on the electricity produced per kilowatt-hour.

The PTC directly reduces the federal income tax for taxable entities. Furthermore, for non-taxable entities such as local governments, educational institutions, or nonprofit organizations, the PTC allows these credits to be monetized, facilitating their involvement in renewable energy initiatives. This provision is applicable for projects that become operational between January 1, 2023, and December 31, 2032, providing a broad window for planning and implementation.

Projects located in designated low-income energy communities receive further incentives. The PTC is structured to be claimable annually for a decade from the start date of operations of the qualifying renewable system, providing long-term financial support. This current structure of the PTC is set to continue through the end of 2024. Starting from January 1, 2025, the credit system will transition to a technology-neutral format, broadening the scope to include a wider array of technologies and fostering a more inclusive approach to renewable energy incentives.

As of the date of this report, the program is still active but solar projects must have “begun construction” by July 4, 2026.

The City project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

Investment Tax Credit

The Investment Tax Credit (ITC) established under the Inflation Reduction Act offers a powerful incentive for deploying renewable energy technologies by providing a reduction in federal tax liability. This reduction is calculated as a percentage of the capital investment made in eligible energy systems. Taxpayers can apply the ITC to their federal income tax for the year the technology is installed, significantly decreasing their tax burden.

Starting January 1, 2023, special provisions enable tax-exempt entities such as local governments and nonprofits to receive direct payments equivalent to the value of the credit. This arrangement improves the liquidity and financial feasibility of renewable projects for these organizations. The scope of eligible technologies under the ITC is broad, encompassing solar panels, wind turbines, fuel cells, and other renewable energy systems.

As of 2025, the Investment Tax Credit (ITC) for solar projects is set at 30% of the eligible costs, encompassing both the equipment and installation expenses. This rate is scheduled to decrease to 26% in 2033 and further to 22% in 2034. Systems rated under 1 megawatt (MW) qualify for the full 30% without having to comply with additional requirements; larger systems will only receive the full amount if they meet specific labor requirements. These include paying prevailing wages to workers during construction and using apprentices to perform a portion of the total construction hours (15% after 2023). Bonus credits are available based on site location, e.g. low-income communities.

The ITC is set to continue delivering these benefits at its current rate until 2032, contingent upon meeting the specific project criteria laid out in the act. Looking ahead, post-2024, the ITC will transition to a technology-neutral system, which will be applicable to all zero-emissions technologies, reflecting a shift towards a more inclusive and adaptable approach to supporting renewable energy development.

HHZP project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

As of the date of this report, the program is still active but critical deadlines for project eligibility and complete operability are quickly approaching in 2026 and 2027, respectively.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) offers financial incentives to non-residential customers of utility Company to encourage the adoption of energy storage systems. These systems help businesses prepare for power outages that may occur due to weather, emergencies, or other unforeseen events. The SGIP funding is authorized through 2024, with incentives structured to decrease over time as funding milestones are reached or as more participants enter the program.

Non-residential customers have access to three types of SGIP rebates: General Market, Equity, and Equity Resilience. Furthermore, SGIP incentives are significantly higher for vulnerable or disadvantaged communities through the Equity and Equity Resilience categories.

Incentives are typically paid upfront for residential systems upon project completion and site verification, while nonresidential systems may receive half upfront with the balance paid based on the system's performance over time. Eligibility for SGIP incentives extends to residential, commercial, industrial, agricultural, and municipal customers of specific utilities including Pacific Gas & Electric, Southern California Edison, SoCalGas, San Diego Gas & Electric, and those managed by the Center for Sustainable Energy.

To be eligible for this rebate, a facility must satisfy two conditions: firstly, it must fall under the category of a government agency, educational institution, non-profit organization, or small business. Secondly, it must fulfill at least one of the following requirements: be located in a Disadvantaged Community (DAC), be situated in a census tract where the Median Household Income of the Statewide Median Income or be situated in California Indian Country.

On the other hand, the equity resilience rebate offers a rate, covering a percentage of the cost of an average energy storage system. To qualify for this rebate, a facility must meet certain requirements. Firstly, it must have experienced two or more utility Public Safety Power Shut-offs (PSPS), or it should be located in a Tier 2 or 3 High Fire Threat District (HFTD) and serve customers in DACs or Low Income Communities. Secondly, it must fulfill at least one of the following additional criteria:

- Be a police station, fire station, emergency response provider, emergency operations center, 911 call center, medical facility, private and public natural gas, electric, water, wastewater, or flood facility, jail or prison, utility-designated PSPS assistance center, cooling center, homeless shelter.
- Be a grocery store, supermarket, or corner store with less than $15 million in annual gross receipts.

- Be an Independent Living Center or a Food Bank.

Modeling Assumptions

The modeling conducted for this feasibility study was based on standard industry benchmarks, available site data, and conservative assumptions to ensure realistic projections. The following key assumptions were applied:

1. **Energy Consumption Baseline** – Historical hourly load data (8,760 points) from the facility was consolidated to represent a typical annual profile. This served as the reference for sizing PV and BESS systems.
2. **PV System Costs** – Capital expenditure (CAPEX) and operations and maintenance (OPEX) values were derived from the National Laboratory of the Rockies (NLR) 2024–2025 benchmarks for commercial rooftop systems. PV CAPEX was assumed at $1.75–$2.00/W DC, with OPEX at ~$19/kW-year.
3. **BESS Costs** – Battery energy storage CAPEX was modeled using NLR 2025 benchmarks at ~$350/kWh. OPEX was assumed at ~$40/kW-year, covering maintenance, monitoring, and lifecycle management.
4. **ITC Incentives** – A 30% Investment Tax Credit (direct pay) was assumed, reducing upfront project cost. No additional low-income or disadvantaged community adders were included, since the site does not qualify.
5. **Performance Parameters** –
    - PV generation modeled with HelioScope using site tilt, azimuth, and shading factors.
    - Battery modeled with 90% round-trip efficiency and daily cycling where applicable.
    - Energy inflation rate of 3% annually applied to utility costs.
6. **Utility Tariff** – The analysis used the most recent Southern California Edison tariff, **TOU-GS-2 Option D**, as published in the file *ELECTRIC_SCHEDULES_TOU-GS-2_2025*. It was assumed under the current **NEM 3** framework. Exported PV energy was valued at ~25% of retail rate. Since tariff structures and prices are subject to future changes, the financial outcomes presented here should be viewed as indicative estimates rather than fixed projections.
7. **Infrastructure** – Electrical interconnection feasibility was preliminarily evaluated using customer-provided single-line diagrams. Minor breaker adjustment (600 A to 500 A) was assumed to comply with NEC 705.12 120% busbar rule for PV backfeed.
8. **Environmental Impact** – Greenhouse gas (GHG) reduction estimates were calculated using EPA eGRID emission factors for the CAMX subregion, applied to modeled PV generation.

Disclaimer: These figures are rough estimates intended for feasibility-level evaluation. If more precise values are required, additional detail must be developed through site-specific engineering, vendor quotations, and utility coordination during the advanced design phase.

Net Energy Metering

Net Energy Metering (NEM) in California is a billing arrangement that allows residential and commercial customers who generate their own electricity, primarily through solar photovoltaic (PV) systems, to receive credit for the surplus energy they contribute to the grid. This system is designed to incentivize the use of renewable energy sources by offsetting the cost of electricity consumption with the energy produced by these installations.

Under NEM, when a solar system generates more electricity than is consumed, the excess energy is sent back to the utility grid, and the customer earns credits. These credits can then be used to offset the cost of energy drawn from the grid when the solar system isn't producing enough to meet the customer's demand, like during nighttime or cloudy days. The rules, rates, and credits under NEM can vary over time, with different iterations such as NEM 1, 2, and the latest NEM 3, each having specific regulations and compensation structures for solar energy production and exchange.

The transition from NEM 2 to NEM 3 in California, which was effective on April 14, 2023, introduced significant changes in the net metering policies for utility customers with photovoltaic (PV) systems. These changes impact

several aspects, particularly the economics of energy arbitrage between PV system owners and the utility. Here's a summary of the key changes:

1) **Reduction in Export Rates:** Under NEM 3, there's a substantial reduction in the rates for excess electricity exported onto the grid by solar systems. This rate has been reduced by approximately 75%, thereby lowering the overall savings for home solar systems and increasing the payback period. This change is a shift from the traditional one-to-one offset of net metering policies, where the price of a kWh of electricity pushed onto the grid was equal to the price of a kWh pulled off the grid.
2) **Implementation of Electrification Rates:** Customers enrolling in NEM 3 are required to use electrification rates instead of regular Time-of-Use (TOU) rates. These electrification rates feature higher on-peak charges and lower off-peak charges, along with a fixed charge of $15 per month. The peak rate period remains from 4 pm to 9 pm.
3) **Export Compensation Based on Avoided Cost Calculator (ACC):** Export compensation under NEM 3 is determined by California's ACC, with specific export rates for every combination of Month, Hour, and Weekday or Weekend. The export value is lowest in the middle of the day when solar energy is abundant on the grid and highest during peak summer demand periods. Notably, the export rates are significantly lower than retail rates during the hours when PV systems are most productive (10 am – 3 pm). To maintain the financial viability of solar PV systems, customers in PG&E and SCE service territories receive an adder on top of the ACC rate, ranging between 2.2 and 9 cents depending on location and customer class.
4) **Shift to a Cost Avoidance System:** NEM 3 introduces a cost avoidance system for exported electricity. This system pays customers the lowest amount a company can pay under the Public Utility Regulatory Policies Act of 1978 (PURPA), which is significantly less than the typical retail rate. This results in customers receiving, on average, 75% less for the electricity they sell back to the grid, with rates varying by month and by hour.
5) **Grandfathering NEM 2 under NEM 3:** Under the recent NEM 3 policy in California, existing customers with a photovoltaic (PV) system installed under NEM 2 can retain the benefits and terms of their NEM 2 agreement, a process known as "grandfathering." However, these customers are restricted from replacing or adding capacity to their PV systems if they wish to maintain their NEM 2 status, as any significant modifications would require transitioning to the terms of NEM 3.

The Net Energy Metering (NEM) 3.0 policy introduces transformative changes, particularly enhancing the value of utilizing Battery Energy Storage Systems (BESS) for owners of solar power systems. A significant aspect of NEM 3.0 is the reduction in compensation rates for surplus electricity fed back into the grid by solar systems, now down to 75%. This adjustment shifts the financial dynamics, making it less lucrative to export excess solar energy to the grid. Instead, storing this surplus energy in a BESS and utilizing it when energy costs are higher becomes a more financially savvy approach.

The utility of BESS extends beyond merely optimizing the use of solar energy. It offers several additional advantages, such as providing backup power during utility blackouts, mitigating charges associated with demand peaks, and enabling energy arbitrage. Energy arbitrage under this system allows for the charging of BESS not only with excess solar energy but also with cheaper grid energy during low-cost periods. This stored energy can then be used in lieu of more expensive grid power at peak times, effectively reducing reliance on utility-supplied energy. Consequently, NEM 3.0 not only promotes more efficient use of solar energy but also broadens the scope of BESS applications, contributing to a more versatile and resilient energy management strategy.

AECOM



Microgrid Feasibility Study
City of Riverside

Site:
Spring Mountain Wastewater Pump Station
7033 Pigeon Pass Rd, Riverside, CA 92507

February 2026

Delivering a better world

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Executive Summary

This study appraises the viability and benefits of distributed energy resource implementation scenarios at the subject site. Four scenarios were developed and compared, key metrics summarized below:

Case	Components	CAPEX ($)	Utility Savings	Payback Period (years)	GHG Reduction ($MTCO_2e$/year)
1	PV	~$100k *(~$72k after 30% ITC)*	~42% (~$11.6k)	~7	~17
2	PV + BESS	~$190k *(~$160k after ITC + SGIP)*	~90% (~$25.3k)	~7	~17
3	BESS	~$112.5k *(~$87.5k after SGIP)*	--	--	--
0	Business as usual (no additions)	--	--	--	--

Note: Capital costs reflect incentive-adjusted values using ITC (direct pay) and SGIP where applicable. All values are approximate.

- Case 1: Photovoltaic (PV) array – Introduces on-site renewable generation and reduces annual utility costs. However, resilience benefits are limited to daytime operation and do not materially improve outage performance.
- Case 2: PV array with battery energy storage system (BESS) – Enables high on-site solar utilization, significantly reduces reliance on utility power under NEM 3, and provides extended resilience by supporting site load during utility outages, including non-daytime periods.
- Case 3: BESS-only – Offers limited economic benefit and is partially redundant given the presence of an existing onsite diesel generator. While backup generation is available, practical runtime is constrained by fuel availability and operational considerations, resulting in approximately five hours of effective coverage, which limits suitability for extended outages.
- Case 0: Business as usual – Maintains current utility dependence. No savings or resilience improvement.

Considering the above, and as detailed further in the technical and economic analysis sections, this study concludes that **Case 2 (PV + BESS)** represents the most suitable and resilient path forward. Although it requires higher upfront capital investment than a PV-only system, this configuration delivers substantially greater operational savings, maximizes the value of on-site solar generation, and materially improves resilience beyond what existing backup generation alone can provide.

Recommended Next Steps

1. Advance to a 30% design phase with detailed site and structural assessments
2. Procure vendor-specific quotations to refine cost estimates beyond what is provided in this study
3. Initiate permitting and interconnection applications with Southern California Edison under the current Net Energy Metering tariff (NEM 3.0)
4. Secure federal incentives, specifically the 30% Investment Tax Credit (direct pay), to lower upfront costs
5. Prepare procurement and construction planning, targeting installation within the next budget cycle.

Background

Purpose

In recent years, especially within the past decade, the impacts of extreme heat and wildfires have been profound through the Inland Empire. Power service disruptions have been increasing in frequency and severity throughout Riverside County, affecting the availability of essential services and community resources.

In 2023, the Western Riverside Council of Governments (WRCOG) received an award (Grant Agreement OPR23145) from the Adaptation Planning Grant Program of the California Governor's Office of Land Use & Climate Innovation Integrated Climate Adaptation and Resilience Program. This program provides funding to help fill local, regional, and tribal planning needs, provides communities the resources to identify climate resilience priorities, and supports the development of a pipeline of climate-resilient infrastructure projects across the state.

As part of this grant-funded project, the Energy Resilience Plan 2.0, WRCOG commissioned microgrid feasibility studies for its member agencies. These studies serve to provide valuation of a potential microgrid at a community-essential facility, as designated by the member agency.

The site selected for the City of Riverside is located at 7033 Pigeon Pass Rd, Riverside, CA 92507

This study presents key insights and findings from the evaluation of distributed energy resource (DER) scenarios, including photovoltaic (PV) array and battery energy storage system (BESS) components, at the subject site. It includes analysis of the site's historic energy demand profile and appraises potential PV array and BESS sizing and siting scenarios accordingly. Notably, the study includes assessment of the generation and storage requirements to support the site's critical loads to enable resilience for a specified number of hours during power service disruptions.

Furthermore, this study outlines the financial implications of self-generation, including estimated cost savings, return on investment (ROI), and potential financing options for the project.

It is important to note that this study serves as a preliminary technical and financial assessment. Its purpose is to provide the City of Riverside with the information to make an informed decision on whether to proceed to next phases of microgrid implementation before committing to detailed engineering design and further investment.

Adaptation Planning Grant Program

As communities in California experience more frequent, prolonged, and severe impacts from climate change, communities and governments at all scales are developing strategies and implementing actions to build a climate-resilient future. However, many jurisdictions, especially under-resourced communities in California, lack the capacity, tools, guidance, and resources to effectively prepare for climate impacts.

The Adaptation Planning Grant Program addresses this capacity gap by providing funding to help fill planning needs, providing communities with the resources to identify climate resilience priorities, and supporting the development of climate resilience projects across the state. The Adaptation Planning Grant Program enables communities to climate risk and adaptation considerations into planning activities and prepare for climate readiness and resilience in the long term.

The Adaptation Planning Grant is part of the Integrated Climate Adaptation and Resiliency Program (ICARP) housed within the Governor's Office of Land Use and Climate Innovation. ICARP advances statewide climate adaptation and resilience by coordinating investments, partnerships, and climate science to ensure people, natural systems, and the built environment are protected, prepared, and thrive in the face of climate change.

Through direct and equity-focused investments and resources, ICARP helps build climate adapted and equitable communities in California, with a focus on solutions that address the impacts of climate change and reduce greenhouse gas emissions. ICARP works to advance these priorities across all levels of government by developing

actionable science and research; providing guidance, tools, and technical assistance; and administering climate resilience-focused grant programs.

Learn more: https://lci.ca.gov/climate/icarp/

Modeling Methodology

This section defines the criteria for sizing the PV array and BESS system components, detailing general parameters, technical requirements, and expected performance criteria.

PV Modeling

1. **Data Inputs**
    - **Solar Resource**: Hourly or sub-hourly irradiance data (e.g., typical meteorological year or on-site measurements)
    - **Site-Specific Factors**: Tilt angle, azimuth, shading analysis, and available roof/ground space
2. **Simulation Approach**
    - Use of HelioScope software to estimate hourly PV production
3. **Sizing Criteria**
    - **Capacity Target**: The sizing criteria are based on 115% of the facility's current annual energy consumption. This approach aims to fully offset the facility's energy usage with the PV array while incorporating an additional 15% capacity to accommodate future demand growth. However, the final system capacity is constrained by the area designated as available by the client.
    - **Performance Ratio**: Evaluate Performance Ratio to ensure consistent system output
    - **Energy Production**: Hourly, daily, monthly, and annual PV generation forecasts
    - **Load Matching**: Amount of PV energy that directly offsets site load vs. excess exported to the grid

BESS Modeling

1. **Data Inputs**
    - **Load Profile**: Detailed electricity consumption and demand patterns
    - **PV Production Profile**: From the PV modeling results
    - **Energy Duration for Resilience**: Determine the critical loads that the BESS will support during islanding operations
2. **Operational Modes**
    - **Energy Shifting / Excess PV Storage**: Battery charges when PV output exceeds site demand, discharges when site demand is high.
    - **Resilience (Standalone BESS)**: Sized to support critical loads during outages
3. **Sizing Criteria**
    - **Capacity (kWh)**: Based on required autonomy (energy shifting, peak shaving, or resilience duration)
    - **Max Discharge/Charge Rate (kW)**: Aligned with site load peaks, PV generation surpluses, and emergency power needs
4. **Simulation Approach**
    - Hourly or sub-hourly dispatch modeling to maximize economic benefit (e.g., demand charge reductions or avoided peak rates)

- Incorporate battery round-trip efficiency, self-discharge, and operational constraints (e.g., partial charge strategies)

5. **Output**

   - **Discharge/Charge Profiles**: Hourly modeling of how the battery is utilized
   - **Cost Savings**: Reduction in energy and demand charges or avoided grid cost
   - **Backup Duration**: If sized for resilience, the total hours/days of critical load coverage

Assumptions

AECOM collected facility data through a request for information process. Energy consumption factors and facility characteristics were identified and integrated in analysis. AECOM used these combined datasets to confirm energy utility consumption baselines.

In performing the analysis, AECOM made the following assumptions:

- This report refers to the Spring Mountain Wastewater Pump Station, located at 7033 Pigeon Pass Rd, Riverside, CA 92507.
- The monthly and annual electricity consumption is derived from load profile data in the client-provided file "9-25-2024 to 9-24-2025 SCE Bills." AECOM applies an internal algorithm to this billing data to generate an estimated 8,760-hour load profile based on the observed annual usage pattern. This generated profile is an approximation rather than a true metered 8,760 dataset, but it provides sufficient resolution and accuracy to infer representative consumption patterns for analysis purposes.
- AECOM utilized the Levelized Cost of Energy (LCOE) for the installed cost per watt of PV installations and BESS, as sourced from the National Laboratory of the Rockies (NLR). This data was used to estimate the hypothetical cost of installing the PV array and BESS at the site, as detailed in this report. For an accurate cost estimation, it is necessary to obtain vendor quotes, which are subject to change due to market-dependent time windows. These quotations are typically conducted during the 60% design phase, at which point there is an understanding of the specific equipment ratings and brands to be used.
- This report evaluates the site's existing electrical infrastructure using customer-provided data on the main breaker and bus capacity, as documented in the client-provided file " SMR-Pgeon Pass As-Built Sewer.pdf" AECOM has assessed whether the existing electrical system can support the proposed PV array and BESS installation. However, as this is a feasibility study, an on-site assessment is required for a definitive determination. A site visit should be conducted during the advanced design phase, typically at the 30% design stage, to confirm site-specific conditions.

1. AECOM has estimated the potential PV generation capacity based on the client-identified available area, as documented in the client-provided file "*VillegasPark-no go areas.docx.*" However, a site assessment is required in later project phases, typically at the 30% design stage, to ensure that the site has the necessary infrastructure for PV array installation. This includes evaluating civil structures, load-bearing capacity, particularly for rooftop installations, and other critical conditions necessary for successful implementation.

- This report uses a regionalized estimate of general production (kWh) to calculate the amount of greenhouse gas emissions avoided through PV generation. The calculation is based on the U.S. EPA Emissions & Generation Resource Integrated Database (eGRID).
- This report clarifies that other charges such as connection fees, required service charges, and taxes remain unchanged. The analysis focuses solely on the bill components directly affected by the installation of PV and BESS under the NEM 3 framework.

AECOM utilized the following tools in conducting the analysis:

- AECOM Internal Tools: Proprietary tools developed by AECOM for analyzing energy patterns and evaluating system performance in simulated environments. These tools are designed to assess energy costs for applications such as peak shaving, energy trading, etc. in DER implementations.
- HelioScope: Web-based software tool used for the design and performance analysis of photovoltaic systems. It combines system layout design with energy simulation, allowing users to model rooftop, ground-mounted, and canopy PV installations. The software factors in module placement, tilt, azimuth, shading, and local weather data to provide accurate estimates of system capacity and expected energy generation.

Site Information

This study is conducted for the Spring Mountain Wastewater Pump Station, located in 7033 Pigeon Pass Rd, Riverside, CA 92507. The site currently consumes about 74,494 kilowatt-hours (kWh) per year.

In terms of electrical infrastructure, the pump station is equipped with a 200-ampere (A) main circuit breaker within the pump station service enclosure, serving a 480/277 volt (V), three-phase, four-wire service. The one line shows the service routed through a power meter and then into the service enclosure distribution and controls.

The site includes a 200 A main transfer switch arranged to accept a standby source through a 200 A, 480 V, three-phase generator receptacle. The drawings also show a trailer mounted portable diesel generator rated 100 kW at 480/277 V, three phase, four-wire intended to connect via the generator plug and support the station during outages.

Process and controls are provided by a pump control panel (PCP) supplied by the pump manufacturer, rated 480 V, three phase, three wire, and feeding three soft start motor starters serving Pump P-1, P-2, and P-3. Each pump is labeled “25” at the motor symbol, indicating three 25 horsepower (hp) pump motors associated with the wet well. The one line also shows level instrumentation (level transducer and limit switches) and associated control and signal wiring to the PCP.

A 10 kilovolt-ampere (kVA), 1 phase transformer is shown feeding a 120/240 Vac, 1 phase, 3 wire “Mini Power Zone” panel schedule (MPZ). The MPZ schedule indicates small branch loads such as control enclosure receptacles and lights, vault GFCI receptacle, vault lights, a radio modem, a gate operator, and a yard light, with spare circuits noted.



Figure 1. Site Location

The user has identified **no-go areas for PV as the below image shows.**



Figure 2. No Go Areas for PV

Incentive Programs

AECOM has identified three key incentive programs that could benefit the subject site, focusing on renewable energy production and advanced energy storage systems.

The Investment Tax Credit (ITC) and Production Tax Credit (PTC) are federal incentives that reduce the cost of renewable energy projects. ITC offers a tax credit based on a percentage of upfront investment costs, while PTC provides a per-kilowatt-hour credit for electricity generated over time.

Production Tax Credit

Under this initiative, the project is eligible for a tax credit ranging from 0.3 cents to 1.5 cents per installed kWh. The specific value of the credit is determined by several factors, including the project's adherence to certain requirements such as complying with labor standards and using domestic materials.

The PTC program pays for each kilowatt-hour produced over a 10-year period, with government entities receiving the benefit as direct pay instead of a tax credit. For this project, with an estimated 86,683 kWh per year, the best case at 1.5 ¢/kWh would yield about $1,300 annually, totaling around $13,002 over 10 years.

Investment Tax Credit

The City can take advantage of either the ITC or the PTC, but both cannot be utilized simultaneously. Since construction has not yet commenced, selecting the ITC is the most advantageous option. Under this scenario, the project is limited to the base 30 percent credit because it does not meet any conditions for additional bonus allocations.

The ITC provides an extra 10 percent credit for projects located in federally designated low-income communities. However, according to the 2016–2020 census tract classification shown in Figure 3, the project site is located outside the eligible low-income area. As a result, the project does not qualify for the additional 10 percent bonus and remains capped at the standard 30 percent ITC.

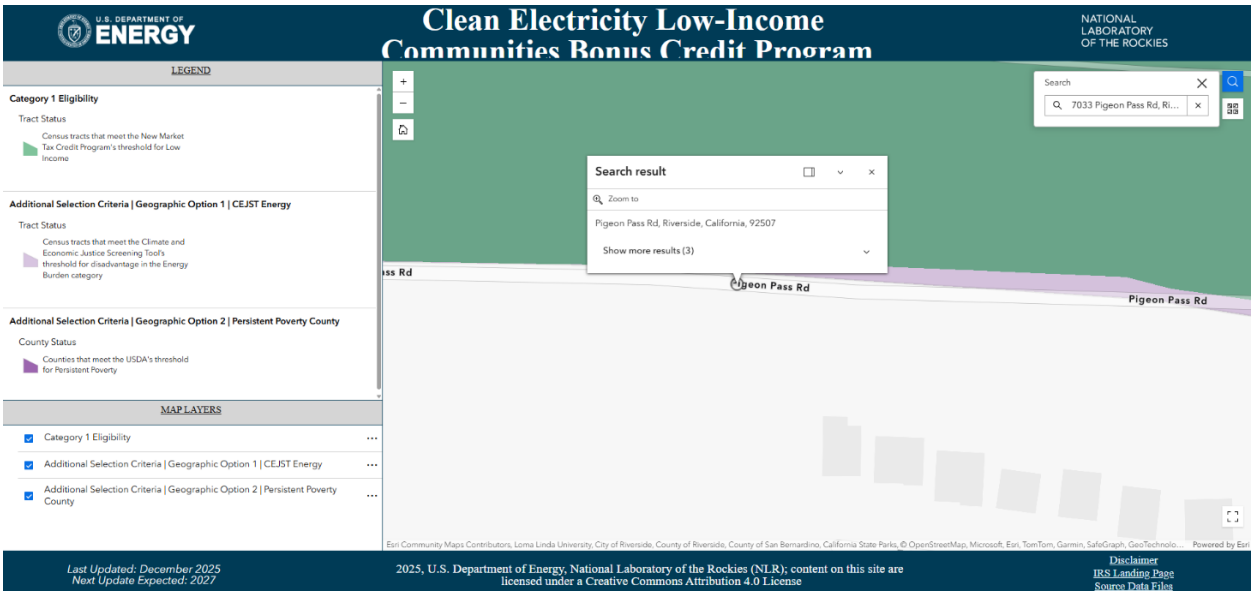


Figure 3. Clean Electricity Low-Income Communities Bonus Credit Program Map

NLR estimates capital expenditure (CAPEX) for commercial PV at $1.75–2.00 / watt (W) direct current (DC). For this study, a 51.7 kilowatt (kW) DC PV system is projected. Based on these CAPEX values, total installation cost ranges from $90,475 to $103,400. With the standard 30 percent ITC, the direct-pay benefit for the City would fall between $27,143 and $31,020.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) is California's primary incentive designed to reduce the upfront cost of energy storage systems. The program has three levels:

- **General Market:** For projects located outside Disadvantaged Communities (DAC). Typical incentive: $0.10/Wh.
- **Equity (DAC):** For project located within a DAC. Incentive: $0.85/Wh.
- **Equity Resilience**: For critical facilities within a DAC and in PSPS or high fire-risk zones. Incentive: $1.00/Wh.

In Case 1, the project site is outside a DAC, so it only qualifies for the General Market level. Using an NLR-based cost of $450/kWh, a 250-kWh battery would cost approximately $112,500. With the General Market incentive of $0.10 /Wh, the project would receive about $25,000, resulting in a net battery cost of roughly $87,500.

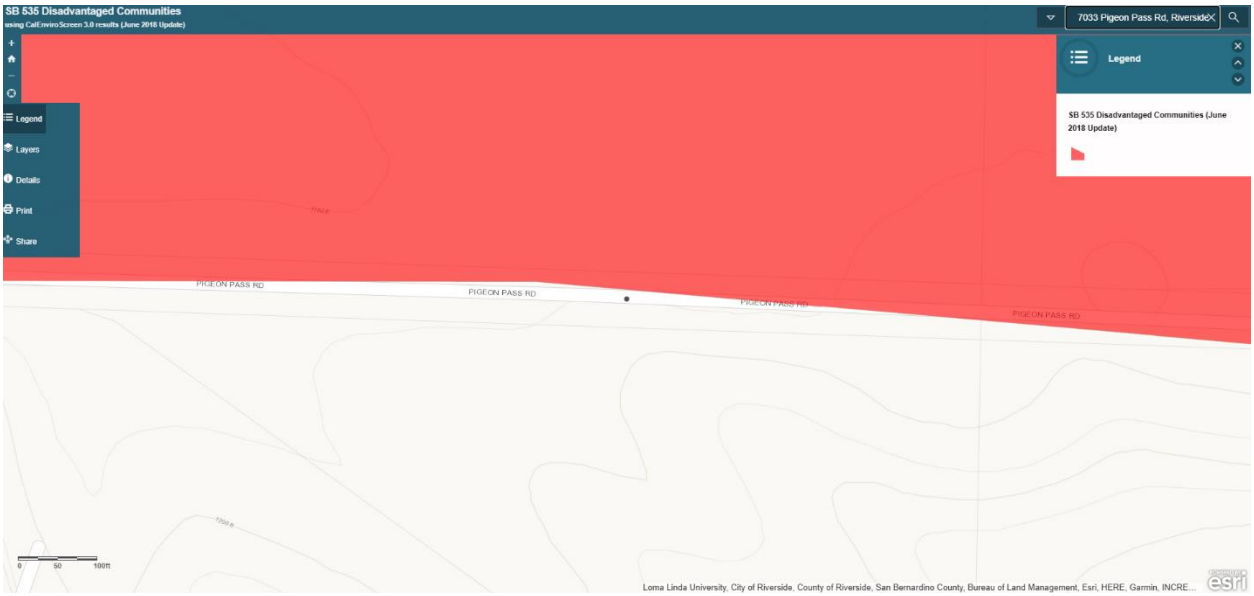


Figure 4. SB 535 Disadvantaged Communities Map

Scenarios & Analysis

Case 0: Current Situation (Baseline)

Tariff & Contract Type

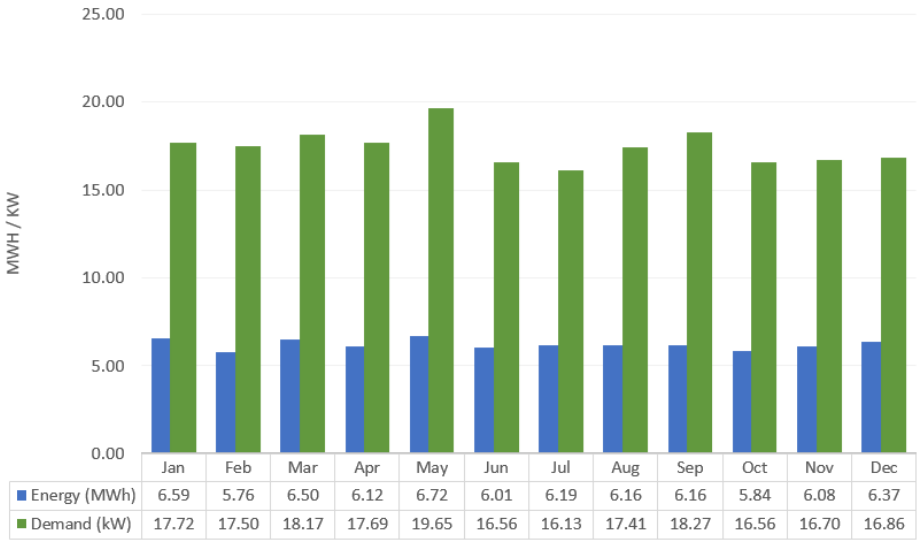
The site is currently served by Southern California Edison (SCE) under the TOU-GS-2 -CPP tariff, which is designed for small to medium commercial customers. This rate structure separates costs into energy charges (based on kilowatt-hours consumed) and demand charges (based on the highest kilowatt demand registered during the billing cycle). In addition, prices vary by time-of-use periods—on-peak, mid-peak, and off-peak—so the timing of energy use significantly affects overall costs.

Being on this tariff means the site's operating expenses are directly tied not only to how much energy is consumed but also to when it is consumed and how high the peak demand reaches.

The tariff cost presents the costs as totals (delivery + bundle). The prices were used as the basis for this study. While they may fluctuate slightly month to month depending on market conditions, these variations are generally minor.

Monthly & Annual Energy Consumption and Demand

The facility currently consumes 74,494 kWh annually, with May being the highest month at about 6.7 kWh and February the lowest at about 5.7 kWh. In terms of demand, May records the peak at around 20 kW, while July is the lowest at about 16.3 kW. The following graph presents this historical data for the 2024–2025 period.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Energy (MWh)	6.59	5.76	6.50	6.12	6.72	6.01	6.19	6.16	6.16	5.84	6.08	6.37
Demand (kW)	17.72	17.50	18.17	17.69	19.65	16.56	16.13	17.41	18.27	16.56	16.70	16.86

Figure 5. Historic Site Energy Profile

Monthly & Annual Energy Costs

The site currently spends about $27,288 per year in energy and demand cost, with approximately $20,816 in energy costs and $8,495 in demand charges, based on tariff TOU-GS-2-CPP simulation. For this analysis, we are focusing only on energy and demand costs, as these are the components directly impacted by the installation of a PV system.

Case 1: PV Only

Installed Capacity & Location

The PV system for the site was sized to offset approximately 115% of current consumption, with the goal of fully offsetting present usage while reserving about 15% additional capacity for future growth. The placement areas for the PV installation were identified according to customer requirements. The system capacity is estimated at 51.7 kW DC, with an expected annual production of about 86,683 kWh.

Figure 6 presented the modeled energy production throughout the year, and Figure 7 identifies the designated PV installation areas on the site.

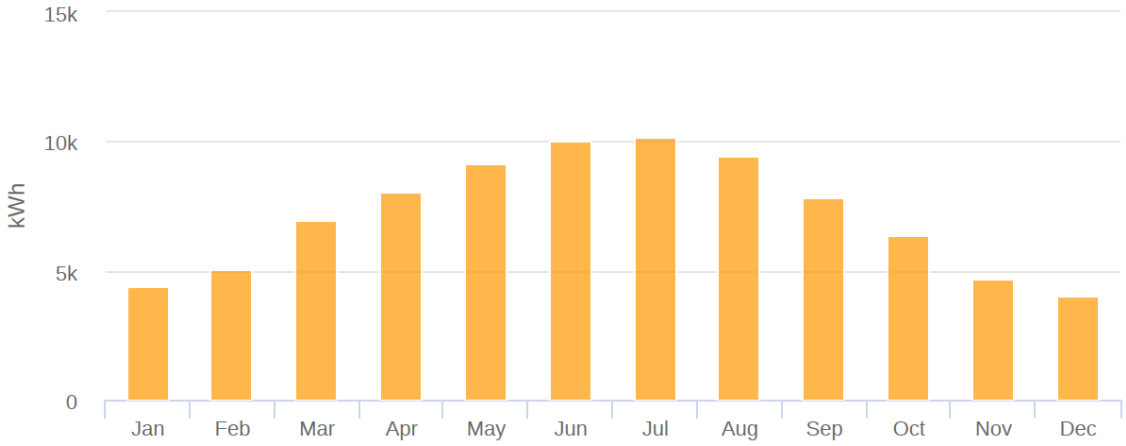


Figure 6. Modeled PV Production



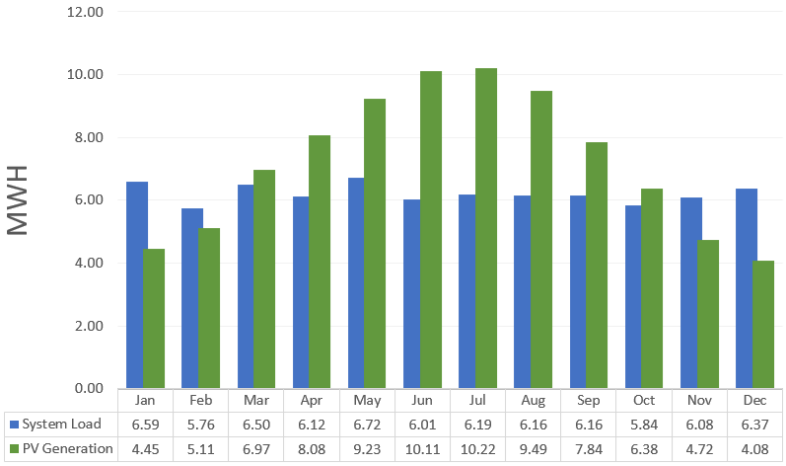
Figure 7. Modeled PV Installation Areas

Modeled PV Production

The modeled PV system is projected to generate an average of **7,224 kWh per month**, with an estimated **annual production of 86,683 kWh**.

This scenario does not include a BESS, so the excess energy produced need be exported to the utility, which requires entering a Net Energy Metering (NEM) contract with the utility service provider. Under the currently available NEM tariff, NEM 3.0, exported electricity is credited at dynamic rates that vary by month, hour of day, and weekday, ranging from as low as $0.01/kWh during midday hours to over $1.00/kWh during peak evening hours in high-demand months like August and September. This study has calculated projected benefits from this arrangement.

Figure 8 compares historic monthly energy consumption and modeled PV generation. Not all solar energy will be consumed on-site, as excess daytime production may exceed demand and be exported to the grid, while nighttime demand cannot be covered since there is no generation after sunset and no battery to store the excess in this scenario.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
System Load	6.59	5.76	6.50	6.12	6.72	6.01	6.19	6.16	6.16	5.84	6.08	6.37
PV Generation	4.45	5.11	6.97	8.08	9.23	10.11	10.22	9.49	7.84	6.38	4.72	4.08

Figure 8. Modeled PV Output vs. Site Demand

Capital Expenditures

Based on NLR benchmark CAPEX values for commercial rooftop solar, the estimated cost to install a 51.7 kW DC PV system in Riverside County, California falls in the range of **$1.75 to $2.00 per watt DC**. This translates to a total investment of **approximately $90,475 – 103,400 for the complete system**.

These figures include **typical equipment, installation, and soft costs**, reflecting average market conditions for commercial-scale projects. Actual costs may vary slightly depending on site-specific conditions such as roof structure, permitting, interconnection requirements, and labor. However, the NLR benchmarks provide a reliable basis for estimating the capital cost of a system of this size and type in the region.

Operating Expenses

According to NLR's 2024 benchmark data, the annual operations and maintenance (OPEX) cost for commercial rooftop PV systems is about $19 per kW DC. For a 51.7 kW DC system, this translates to an estimated yearly OPEX of roughly $982 covering routine maintenance, monitoring, and related operational expenses.

Economic Metrics

The analysis shows that installing a PV system at the site under NEM3 provides measurable financial benefits by offsetting both energy and demand charges. Without solar, the facility currently spends about $27,288 annually on utility costs. With the PV system in operation, the energy cost is reduced to approximately $10,447 per year, while the demand cost drops to about $5,241 per year. In addition, the system generates excess electricity during the day that cannot be fully consumed on-site. Under NEM3 rules, this exported energy represents an additional benefit of roughly $1,722 annually.

Taken together, these reductions and export credits bring the facility's total utility bill down to $15,688 per year, achieving an overall savings of about 43% compared to current expenses.

Payback Period and Return on Investment

The financial analysis shows that without PV, the facility spends approximately $27,288 per year on utility costs. With a 51.7 kW DC PV system installed, the annual cost is reduced to about $15,688, resulting in yearly savings of roughly $11,600. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system is estimated at $103,400, but with the 30 percent ITC direct pay, the net investment is reduced to approximately $72,380. In addition, the system carries an annual OPEX of $982, which slightly offsets the yearly savings. Taking these factors into account, the project generates a net benefit of about $11,600 minus 982 per year after OPEX. This results in a simple payback period of approximately 7 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross Savings ($)	Net Savings after OPEX ($)	Cumulative Cash Flow ($)
1	11,600	10,618	-61,762
2	11,948	10,936	-50,826
3	12,306	11,264	-39,562
4	12,675	11,602	-27,959
5	13,056	11,950	-16,009
6	13,447	12,309	-3,700
7	13,851	12,678	8,978
8	14,266	13,059	22,037
9	14,694	13,450	35,487
10	15,135	13,854	49,341
15	17,546	16,060	125,099
20	20,340	18,618	212,924

Table 1. Return on Investment w/ 3% Inflation: Case 1

Technical Feasibility

The site electrical service is 480 V, 3-phase, 3-wire from Southern California Edison and is protected by a 200 A main circuit breaker. A 200 A manual transfer switch is provided for connection of a trailer-mounted generator, and the main feeder between the service equipment and transfer switch is indicated as 2-inch conduit with (3) 3/0 conductors and (1) #6 equipment grounding conductor.

For a load-side PV interconnection at this service equipment, NEC 705 bus backfeed compliance is governed by the 120 percent rule: (Main OCPD rating + PV backfeed OCPD rating) shall not exceed 1.20 times the bus rating. With the existing 200 A main, the maximum allowable PV backfeed breaker equals (1.20 × Bus rating) minus 200 A. If the service bus is 200 A, the allowable PV backfeed is 40 A maximum.

A 51.7 kW PV system interconnected at 480 V, 3-phase typically requires an AC output OCPD on the order of 60 to 70 A, which exceeds a 40 A backfeed limit. To accommodate a 60 A class PV backfeed breaker with a 200 A main under the 120 percent rule, the service bus must be at least 225 A (since 200 A + 60 A = 260 A, and 1.20 × 225 A = 270 A). If the existing service equipment bus is not at least 225 A, a compliant solution requires either a supply-side connection on the service conductors, or replacement/upgrade of the service equipment to a higher bus rating and appropriately rated overcurrent protection.

The PV interconnection shall include a utility-required visible, lockable AC disconnect and shall be grounded and bonded to the existing grounding system. Protection coordination shall be maintained at the service level by verifying the PV interconnection OCPD interrupting rating and ensuring conductor ampacity and equipment ratings match the 480 V service configuration and the existing 200 A service protection scheme.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 86,683 kWh per year. Using the U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:"

- Carbon dioxide (CO_2): 37,134.9972 lb (16.8442 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 37,273.6900 lb (16.9071 metric tons) avoided annually
- Nitrogen oxides (NOx): 28.7788 lb (13.0538 kg) avoided annually
- Sulfur dioxide (SO_2): 1.7337 lb (0.7864 kg) avoided annually

Case 2: PV + BESS

System Components

This scenario assumes the same PV array described in Case 1 and a BESS sized for surplus PV production. The day with the highest energy surplus in our simulation occurred on Jun 02, during which the PV system produced 363 kWh, the site consumed 185 kWh, and the resulting surplus was 177 kWh. For size the BESS, we ran several iterations based on the available surplus energy and applied an algorithm that simulates the charge and discharge cycles of one year. This techno-financial analysis indicates that the optimal BESS capacity is approximately 250 kWh.

This simulation factor ensures that even under variations in production or demand, all possible excess solar energy generated during the day can be stored. The stored energy is then available for use at night or during periods when PV production does not fully cover the site's demand.

By doing so, most of the units of solar energy produced on-site are consumed daily by the facility, preventing as little as possible any export to the grid.

Modeled Energy Flows

By installing a 250 kWh battery, we ensure that all the energy generated on-site is consumed by the facility itself. The charge and discharge profile of the battery is designed so that any PV surplus during the day is immediately stored in the battery rather than exported to the grid. Later, if the site demand exceeds the PV generation while there is still energy stored in the battery, the deficit is supplied from the battery.

This operational strategy minimizes or even eliminates consumption from the utility, since the PV and battery combination is prioritized to cover the load at all times. On an annual basis, the system is expected to produce slightly more energy than the site requires, leaving a surplus of around 10%, but this excess is negligible in terms of the overall utility bill.

Capital Expenditures

According to NLR benchmark data, the capital expenditure (CAPEX) for a commercial-scale 51.7 kW DC rooftop PV system in Riverside, California is estimated at $72,380 under ITC incentive, based on installation costs of $1.75–2.00 per watt DC.

For energy storage, NLR's 2025 cost projections indicate a high-cost benchmark of approximately $450 per kWh. Applying this value to a commercial-scale 250 kWh battery system results in an estimated capital cost of approximately $112,500. Under the SGIP program, this incentive level can effectively fund up to 10% of the total BESS system cost.

Together, the combined CAPEX for the PV and BESS systems under ITC and SGIP programs is estimated at $159,880 representing the expected upfront investment for a commercial solar-plus-storage project of this size.

Operating Expenses

According to NLR benchmark data, the annual operations and maintenance (OPEX) cost for a commercial-scale 51.7 kW DC rooftop PV system is estimated at $982 USD.

NLR data indicates an operating cost of approximately $4 per kW-year. For a commercial-scale 250 kWh battery system, this results in an annual OPEX of about $1,000.

Together, the combined OPEX for the PV and BESS systems is approximately $1,982 per year, covering routine maintenance, monitoring, and system management.

Economic Metrics

The analysis shows that installing a commercial-scale PV system paired with a 250 kWh battery under NEM 3 provides strong financial advantages by allowing a substantial portion of the solar energy produced by the PV system to be consumed on-site.

In several cases, PV production exceeds the facility's demand, and the surplus can be stored in the BESS for later use. However, without a battery system, the facility cannot absorb all of this excess energy, since any unused generation must be consumed the moment it is produced. This unused energy would otherwise need to be exported to the utility grid, where under current NEM rules it would be compensated at only about 25 percent of the retail electricity rate. Given that time-of-use pricing makes stored energy far more valuable during high-cost periods, it becomes financially preferable to store surplus solar rather than sell it.

Without a BESS, exporting this excess would generate $1,722 but the facility would still face an annual utility cost of $15,688 By contrast, installing the BESS reduces grid reliance and allows the facility to consume nearly all of its solar production during higher-priced periods, resulting in a significantly lower annual utility bill of $2,011.

To remain conservative, this analysis assumes that 10% of annual energy costs remain due to efficiency losses, imperfect alignment of PV output and site load, and seasonal variability.

It is important to note that other charges — such as connection fees, requisite charges, and taxes — remain unaffected. This analysis focuses only on those bill components directly impacted by the installation of PV and BESS under the NEM 3 framework.

Payback Period and Return on Investment

The financial analysis shows that without PV + BESS, the facility spends approximately $27,288 per year on utility costs. With a 51.7 kW DC PV system and 250 kWh BESS system installed, the annual cost is reduced to about $2,011 resulting in yearly savings of roughly $25,277. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system under ITC and SGIP incentives is estimated at $159,880. In addition, the system carries an annual OPEX of $ 1,982 Taking these factors into account, the combined system generates a net benefit of about 23,295 per year after OPEX. This results in a simple payback period of approximately 7 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross-Savings ($)	Net-Savings after OPEX ($)	Cumulative Cash Flow ($)
1	25,277	23,295	-136,585
2	26,036	23,994	-112,591
3	26,817	24,714	-87,877
4	27,621	25,455	-62,421
5	28,450	26,219	-36,202
6	29,303	27,006	-9,197
7	30,182	27,816	18,619
8	31,088	28,650	47,270
9	32,021	29,510	76,779
10	32,981	30,395	107,174
15	38,234	35,236	273,387
20	44,324	40,848	466,073

Table 2. Return on Investment w/ 3% Inflation: Case 2

Technical Feasibility

The existing electrical service is provided by Southern California Edison to a pad mounted transformer and utility power meter, feeding a 480 V, 3 phase service rated 200 A with a 200 A main circuit breaker located in the pump station service enclosure.

Downstream of the service, a 200 A main transfer switch is shown to serve the pump station loads, and a 200 A, 480 V, 3 phase generator receptacle is provided for a trailer mounted portable diesel generator connection. This indicates the pump station is arranged to transfer between normal utility power and an onsite temporary generator source.

The motor control equipment shown includes multiple pump starters (three pumps labeled 25) and a control power section, including a small power transformer (10 kVA shown) supporting the PLC and associated controls. Any PV inverter output and BESS power conversion system intended to serve this site would need to interconnect at the 480 V, three-phase level within the service enclosure.

To add a 51.7 kW DC PV system and a 250 kWh BESS, new dedicated interconnection equipment should be added, including (at minimum) a new 480 V PV backfeed breaker (or fused disconnect) sized to the selected inverter output current, a new 480 V BESS breaker sized to the selected PCS charge and discharge current, utility visible lockable AC disconnect(s), and required labeling and rapid shutdown and shutdown controls as applicable to the final equipment selection.

A protection and interconnection review is required at the 200 A service equipment and the 200 A transfer switch. If the PV and BESS are connected on the load side of the 200 A service equipment or through the transfer switch, bus and breaker limitations must be checked for NEC 705.12 compliance and for compatibility with the transfer scheme. If compliance cannot be achieved on the load side, the practical alternatives are (1) a supply side interconnection ahead of the 200 A main circuit breaker with utility approved metering and protection, or (2) replacement or upgrade of the service and transfer equipment to a higher ampacity configuration that can accept the additional sources.

Because a generator receptacle and transfer switch are present, the PV and BESS controls must be coordinated to prevent unintended backfeed into the utility or into the generator connection during transfer and generator operation. If the intent is to have the PV and BESS support loads during utility outages, the design will require a defined islanding strategy and controls coordinated with the transfer switch; otherwise, the PV and BESS should be arranged to trip offline upon loss of utility and during generator operation.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 86,683 kWh per year. Using the U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:"

- Carbon dioxide (CO_2): 37,134.9972 lbs (16.8442 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 37,273.6900 lbs (16.9071 metric tons) avoided annually
- Nitrogen oxides (NO_x): 28.7788 lbs (13.0538 kg) avoided annually
- Sulfur dioxide (SO_2): 1.7337 lbs (0.7864 kg) avoided annually

CASE 3: BESS Only

Critical Load Identification

Based on the facility classification as an operator center, the systems that must be supported by emergency or legally required standby power are limited to life-safety and mission-critical functions as defined by NEC 700, NEC 701, NFPA 110, and NFPA 72. From the one-line diagram, the electrical scope is dominated by control panels, motor starters, instrumentation, communications, and monitoring equipment associated with continuous operation and supervision

These loads align with emergency illumination for egress, fire alarm and signaling power, communications and dispatch functions, and security or control systems required to maintain safe operation. Applying a conservative code-consistent allocation of 25 percent of the total connected load results in a rough estimation of critical load of 62.5 kW.

Required Backup Duration

The drawings do not indicate a minimum emergency runtime for standby or emergency systems. In the absence of an explicitly stated duration, a default requirement of 4 hours is applied, consistent with common practice for emergency and standby systems when specific authority having jurisdiction criteria are not identified.

Battery Capacity & Infrastructure

The battery energy storage system is sized directly from the emergency demand and required duration. A continuous emergency demand of 62.5 kW over 4 hours results in a required usable energy capacity of 250 kWh, with a power rating of 62.5 kW. This sizing assumes full availability of the battery for emergency operation only. Integration requires connection on the emergency distribution side through an automatic transfer scheme, sufficient bus capacity at the emergency panel, appropriately rated breakers, and dedicated feeders to segregated emergency circuits. Routing must maintain separation between normal and emergency systems as shown in the one-line architecture

Capital Expenditures

Using cost benchmarks published by the National Laboratory of the Rockies (NLR), the estimated **capital cost** (CAPEX) for a 250 kWh / 20 kW battery energy storage system is approximately $**112,500 and under SGIP will be about $87,500**. This figure includes the battery cabinets, inverter/PCS, microgrid controller with ATS, installation, protections, and engineering.

Operating Expenses

The expected **operating cost** (OPEX) is about **$1,000 per year**, also based on NLR reference values. This covers preventive maintenance, monitoring software, and NFPA 110 testing requirements. Battery replacement is typically required after 10–12 years of service.

Return on Investment & Qualitative Benefits

While a conventional financial return cannot be directly applied to this case, the value of a battery energy storage system for an operator center is defined by resilience, reliability, and compliance. The system ensures uninterrupted operation of life-safety signaling, communications, and monitoring equipment during extended utility outages, supporting compliance with NFPA 110, NFPA 70, and NFPA 72.

However, for this facility, the justification for a battery system must be weighed against existing backup assets shown in the electrical drawings. If existing generator capacity already exceeds the critical load requirement, the additional resilience provided by the battery may be limited relative to cost, shifting the decision toward redundancy preferences, operational policy, or long-term reliability planning.

Technical Considerations

Key integration considerations include available bus capacity at the emergency distribution equipment, compliance with the 120 percent load-side interconnection limitation where applicable, and verification that breakers and feeders are adequately rated for the added source. Emergency and normal circuits must remain segregated through the automatic transfer scheme. A short-circuit and coordination study is required to confirm interrupting ratings, along with validation of transfer sequences between utility, generator, and battery. The battery system must also address fire and safety requirements, including enclosure placement and UL 9540A considerations, consistent with the electrical configuration shown in the one-line diagram.

Decision Matrix and Scenario Comparison

In order to determine the most appropriate scenario for the site, four scenarios were developed and analyzed: business as usual (Case 0), installing a PV system only (Case 1), installing PV with a BESS (Case 2), and installing a BESS only (Case 3). Each case was evaluated in terms of resilience value, capital and operating expenditures, energy savings, payback period, and technical feasibility. The decision matrix summarizes the comparative performance of these options.

Criteria	Case 0: Baseline	Case 1: PV Only	Case 2: PV + BESS	Case 3: BESS Only
Resilience Benefit	None	Limited (daytime only)	Moderate (self-consumption, some coverage)	High (but redundant due to existing 125 kW generator)
CAPEX ($)	0	~$90k–$103k *(~$63k–$72k after 30% ITC)*	~$203k–$216k *(~$160k after ITC + SGIP)*	~$112.5k *(~$87.5k after SGIP)*
OPEX ($/yr)	Current	~$982	~$1,982	~$1,000
Annual Utility Bill ($)	~$27,288	~$16,688	~$2,011	~$27,288 (no reduction)
Annual Savings ($)	–	~$11,600	~$25,277	Minimal (non-financial)
Payback Period	–	~7 years	~7 years	No ROI
GHG Reduction	None	~21 $MTCO_2e$ avoided annually	Same as Case 1	None
Technical Feasibility	Already in place	Requires NEC 705-compliant interconnection or service modification	Requires PV + storage integration and interconnection coordination	Technically feasible, but limited incremental benefit due to existing Backup generator

Table 3. Scenario Comparison

Conclusion

Based on the comparative analysis, **Case 2 (PV + BESS)** emerges as the preferred scenario for the site. While Case 1 (PV-only) delivers meaningful energy cost reductions and a favorable payback, it does not materially enhance resilience beyond normal grid-tied operation. Case 3 (BESS-only) was not selected, as the site already has an existing diesel generator capable of supporting critical operations; however, its practical runtime is limited by fuel logistics, operational constraints, and testing requirements, resulting in an effective backup duration of approximately 4 hours, which is not well suited for extended outages.

The PV + BESS configuration provides the most balanced and robust solution by combining on-site renewable generation with energy storage to significantly reduce utility dependence while also extending outage survivability beyond what the existing generator alone can reasonably provide. Although the site already possesses backup generation, the battery system enables seamless, fuel-independent support of critical loads, reduces generator runtime and wear, and enhances operational continuity during utility interruptions, particularly during non-daytime hours when PV-only systems cannot supply load.

Therefore, Case 2 offers the best overall balance between resilience enhancement, operational reliability, long-term cost control, and infrastructure optimization. While this option requires higher upfront capital investment compared to PV-only, the incremental cost is justified by the substantial reduction in annual utility costs, improved self-consumption of on-site solar energy under NEM 3, and the added value of extended, low-maintenance backup capability without sole reliance on diesel generation.

Summary of Strategy & Benefits

The selected strategy focuses on installing a rooftop PV system sized to offset approximately 110% of the facility's annual energy consumption, paired with a battery energy storage system optimized to capture surplus daytime generation and serve site load during evening hours and utility outages. This approach achieves the following benefits:

- **Resilience:** Combines existing backup generation with a fuel-independent BESS, extending effective backup capability beyond the practical ~4-hour generator-only runtime and improving outage response without reliance on fuel availability.
- **Economic Savings:** Reduces annual utility costs by approximately 90%, lowering expenditures from about $27,288 to approximately $2,011 through maximized on-site consumption and reduced exposure to time-of-use pricing.
- **Financial Feasibility:** Delivers a simple payback period of approximately 7 years when accounting for ITC and SGIP incentives, after which the facility continues to accrue inflation-protected savings over the remaining system life.
- **Environmental Impact:** Offsets approximately 21 metric tons of CO_2e emissions annually, directly contributing to local and regional decarbonization goals while reducing generator runtime and associated emissions during outages.
- **Technical Integration:** Builds upon existing electrical infrastructure and backup systems, requiring coordinated interconnection and controls rather than full service replacement, while maintaining compliance with NEC 705 and emergency power requirements.
- **Operational Practicality:** Provides a layered resilience strategy that minimizes operational complexity, reduces dependence on diesel fuel logistics, and enhances long-term reliability for an essential service facility.

Next Steps

To advance the project, the following steps are recommended:

1. **Detailed Design & Site Assessment:** Conduct a 30% design phase evaluation, including structural assessment of the roof, electrical interconnection details, and shading analysis
2. **Vendor Quotations:** Obtain updated vendor quotes for PV system equipment, installation, and interconnection to refine cost estimates beyond NLR benchmarks
3. **Permitting & Interconnection:** Coordinate with Southern California Edison (SCE) to complete the interconnection study and ensure compliance with NEM 3 tariff rules
4. **Finalize Incentive Applications:** Submit applications for the 30% ITC (direct pay) to secure federal funding and reduce upfront capital cost
5. **Procurement & Installation:** Issue RFPs for procurement and construction, selecting qualified contractors with experience in municipal PV installations
6. **Commissioning & Monitoring:** Upon installation, perform commissioning tests, integrate the system with monitoring platforms, and establish an operations and maintenance (O&M) plan to ensure reliable long-term performance

Appendix

Incentive Programs

This section outlines how the incentive programs function and provides relevant information about them. Specific application of these programs to presented scenarios is explored in previous sections.

Inflation Reduction Act

The Inflation Reduction Act of 2022 stands as a significant piece of legislation designed to strengthen the United States' commitment to fighting climate change by making considerable investments in renewable energy. A key feature of the Inflation Reduction Act is its financial incentives, namely the Investment Tax Credit (ITC) and the Production Tax Credit (PTC), which aim to accelerate the adoption of renewable energy technologies.

The ITC allows for a significant tax credit for investments in renewable energy technologies, including solar panels and wind turbines, directly reducing the upfront cost of these systems. This makes renewable projects more financially viable and attractive to investors and consumers alike. On the other hand, the PTC provides a per-kilowatt-hour tax relief for the production of energy from renewable sources, incentivizing the operation and expansion of renewable energy facilities.

Notably, Inflation Reduction Act programs have been subject to change in recent legislation. Presented here are active opportunities as of the time of the report.

Production Tax Credit

The Production Tax Credit (PTC) within the framework of the Inflation Reduction Act offers considerable financial incentives for renewable energy projects, primarily designed to decrease the federal income tax liability based on the electricity produced per kilowatt-hour.

The PTC directly reduces the federal income tax for taxable entities. Furthermore, for non-taxable entities such as local governments, educational institutions, or nonprofit organizations, the PTC allows these credits to be monetized, facilitating their involvement in renewable energy initiatives. This provision is applicable for projects that become operational between January 1, 2023, and December 31, 2032, providing a broad window for planning and implementation.

Projects located in designated low-income energy communities receive further incentives. The PTC is structured to be claimable annually for a decade from the start date of operations of the qualifying renewable system, providing long-term financial support. This current structure of the PTC is set to continue through the end of 2024. Starting from January 1, 2025, the credit system will transition to a technology-neutral format, broadening the scope to include a wider array of technologies and fostering a more inclusive approach to renewable energy incentives.

As of the date of this report, the program is still active but solar projects must have “begun construction” by July 4, 2026.

The City project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

Investment Tax Credit

The Investment Tax Credit (ITC) established under the Inflation Reduction Act offers a powerful incentive for deploying renewable energy technologies by providing a reduction in federal tax liability. This reduction is calculated as a percentage of the capital investment made in eligible energy systems. Taxpayers can apply the ITC to their federal income tax for the year the technology is installed, significantly decreasing their tax burden.

Starting January 1, 2023, special provisions enable tax-exempt entities such as local governments and nonprofits to receive direct payments equivalent to the value of the credit. This arrangement improves the liquidity and financial feasibility of renewable projects for these organizations. The scope of eligible technologies under the ITC is broad, encompassing solar panels, wind turbines, fuel cells, and other renewable energy systems.

As of 2025, the Investment Tax Credit (ITC) for solar projects is set at 30% of the eligible costs, encompassing both the equipment and installation expenses. This rate is scheduled to decrease to 26% in 2033 and further to 22% in 2034. Systems rated under 1 megawatt (MW) qualify for the full 30% without having to comply with additional requirements; larger systems will only receive the full amount if they meet specific labor requirements. These include paying prevailing wages to workers during construction and using apprentices to perform a portion of the total construction hours (15% after 2023). Bonus credits are available based on site location, e.g., low-income communities.

The ITC is set to continue delivering these benefits at its current rate until 2032, contingent upon meeting the specific project criteria laid out in the act. Looking ahead, post-2024, the ITC will transition to a technology-neutral system, which will be applicable to all zero-emissions technologies, reflecting a shift towards a more inclusive and adaptable approach to supporting renewable energy development.

HHZP project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

As of the date of this report, the program is still active but critical deadlines for project eligibility and complete operability are quickly approaching in 2026 and 2027, respectively.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) offers financial incentives to non-residential customers of utility Company to encourage the adoption of energy storage systems. These systems help businesses prepare for power outages that may occur due to weather, emergencies, or other unforeseen events. The SGIP funding is authorized through 2024, with incentives structured to decrease over time as funding milestones are reached or as more participants enter the program.

Non-residential customers have access to three types of SGIP rebates: General Market, Equity, and Equity Resilience. Furthermore, SGIP incentives are significantly higher for vulnerable or disadvantaged communities through the Equity and Equity Resilience categories.

Incentives are typically paid upfront for residential systems upon project completion and site verification, while nonresidential systems may receive half upfront with the balance paid based on the system's performance over time. Eligibility for SGIP incentives extends to residential, commercial, industrial, agricultural, and municipal customers of specific utilities including Pacific Gas & Electric, Southern California Edison, SoCalGas, San Diego Gas & Electric, and those managed by the Center for Sustainable Energy.

To be eligible for this rebate, a facility must satisfy two conditions: firstly, it must fall under the category of a government agency, educational institution, non-profit organization, or small business. Secondly, it must fulfill at least one of the following requirements: be located in a Disadvantaged Community (DAC), be situated in a census tract where the Median Household Income of the Statewide Median Income or be situated in California Indian Country.

On the other hand, the equity resilience rebate offers a rate, covering a percentage of the cost of an average energy storage system. To qualify for this rebate, a facility must meet certain requirements. Firstly, it must have experienced two or more utility Public Safety Power Shut-offs (PSPS), or it should be located in a Tier 2 or 3 High Fire Threat District (HFTD) and serve customers in DACs or Low Income Communities. Secondly, it must fulfill at least one of the following additional criteria:

- Be a police station, fire station, emergency response provider, emergency operations center, 911 call center, medical facility, private and public natural gas, electric, water, wastewater, or flood facility, jail or prison, utility-designated PSPS assistance center, cooling center, homeless shelter.
- Be a grocery store, supermarket, or corner store with less than $15 million in annual gross receipts.

- Be an Independent Living Center or a Food Bank.

Modeling Assumptions

The modeling conducted for this feasibility study was based on standard industry benchmarks, available site data, and conservative assumptions to ensure realistic projections. The following key assumptions were applied:

1. **Energy Consumption Baseline** – Historical hourly load data (8,760 points) from the facility was consolidated to represent a typical annual profile. This served as the reference for sizing PV and BESS systems.
2. **PV System Costs** – Capital expenditure (CAPEX) and operations and maintenance (OPEX) values were derived from the National Laboratory of the Rockies (NLR) 2024–2025 benchmarks for commercial rooftop systems. PV CAPEX was assumed at $1.75–$2.00/W DC, with OPEX at ~$19/kW-year.
3. **BESS Costs** – Battery energy storage CAPEX was modeled using NLR 2025 benchmarks at ~$350/kWh. OPEX was assumed at ~$40/kW-year, covering maintenance, monitoring, and lifecycle management.
4. **ITC Incentives** – A 30% Investment Tax Credit (direct pay) was assumed, reducing upfront project cost. No additional low-income or disadvantaged community adders were included since the site does not qualify.
5. **Performance Parameters** –
    - PV generation modeled with HelioScope using site tilt, azimuth, and shading factors.
    - Battery modeled with 90% round-trip efficiency and daily cycling where applicable.
    - Energy inflation rate of 3% annually applied to utility costs.
6. **Utility Tariff** – The analysis used the most recent Southern California Edison tariff, **TOU-GS-2 Option D**, as published in the file *ELECTRIC_SCHEDULES_TOU-GS-2_2025*. It was assumed under the current **NEM 3** framework. Exported PV energy was valued at ~25% of retail rate. Since tariff structures and prices are subject to future changes, the financial outcomes presented here should be viewed as indicative estimates rather than fixed projections.
7. **Infrastructure** – Electrical interconnection feasibility was preliminarily evaluated using customer-provided single-line diagrams. Minor breaker adjustment (600 A to 500 A) was assumed to comply with NEC 705.12 120% busbar rule for PV backfeed.
8. **Environmental Impact** – Greenhouse gas (GHG) reduction estimates were calculated using EPA eGRID emission factors for the CAMX subregion, applied to modeled PV generation.

Disclaimer: These figures are rough estimates intended for feasibility-level evaluation. If more precise values are required, additional detail must be developed through site-specific engineering, vendor quotations, and utility coordination during the advanced design phase.

Net Energy Metering

Net Energy Metering (NEM) in California is a billing arrangement that allows residential and commercial customers who generate their own electricity, primarily through solar photovoltaic (PV) systems, to receive credit for the surplus energy they contribute to the grid. This system is designed to incentivize the use of renewable energy sources by offsetting the cost of electricity consumption with the energy produced by these installations.

Under NEM, when a solar system generates more electricity than is consumed, the excess energy is sent back to the utility grid, and the customer earns credits. These credits can then be used to offset the cost of energy drawn from the grid when the solar system is not producing enough to meet the customer's demand, like during nighttime or cloudy days. The rules, rates, and credits under NEM can vary over time, with different iterations such as NEM 1, 2, and the latest NEM 3, each having specific regulations and compensation structures for solar energy production and exchange.

The transition from NEM 2 to NEM 3 in California, which was effective on April 14, 2023, introduced significant changes in the net metering policies for utility customers with photovoltaic (PV) systems. These changes impact

several aspects, particularly the economics of energy arbitrage between PV system owners and the utility. Here is a summary of the key changes:

1) **Reduction in Export Rates:** Under NEM 3, there is a substantial reduction in the rates for excess electricity exported onto the grid by solar systems. This rate has been reduced by approximately 75%, thereby lowering the overall savings for home solar systems and increasing the payback period. This change is a shift from the traditional one-to-one offset of net metering policies, where the price of a kWh of electricity pushed onto the grid was equal to the price of a kWh pulled off the grid.
2) **Implementation of Electrification Rates:** Customers enrolling in NEM 3 are required to use electrification rates instead of regular Time-of-Use (TOU) rates. These electrification rates feature higher on-peak charges and lower off-peak charges, along with a fixed charge of $15 per month. The peak rate period remains from 4 pm to 9 pm.
3) **Export Compensation Based on Avoided Cost Calculator (ACC):** Export compensation under NEM 3 is determined by California's ACC, with specific export rates for every combination of Month, Hour, and Weekday or Weekend. The export value is lowest in the middle of the day when solar energy is abundant on the grid and highest during peak summer demand periods. Notably, the export rates are significantly lower than retail rates during the hours when PV systems are most productive (10 am – 3 pm). To maintain the financial viability of solar PV systems, customers in PG&E and SCE service territories receive an adder on top of the ACC rate, ranging between 2.2 and 9 cents depending on location and customer class.
4) **Shift to a Cost Avoidance System:** NEM 3 introduces a cost avoidance system for exported electricity. This system pays customers the lowest amount a company can pay under the Public Utility Regulatory Policies Act of 1978 (PURPA), which is significantly less than the typical retail rate. This results in customers receiving, on average, 75% less for the electricity they sell back to the grid, with rates varying by month and by hour.
5) **Grandfathering NEM 2 under NEM 3:** Under the recent NEM 3 policy in California, existing customers with a photovoltaic (PV) system installed under NEM 2 can retain the benefits and terms of their NEM 2 agreement, a process known as "grandfathering." However, these customers are restricted from replacing or adding capacity to their PV systems if they wish to maintain their NEM 2 status, as any significant modifications would require transitioning to the terms of NEM 3.

The Net Energy Metering (NEM) 3.0 policy introduces transformative changes, particularly enhancing the value of utilizing Battery Energy Storage Systems (BESS) for owners of solar power systems. A significant aspect of NEM 3.0 is the reduction in compensation rates for surplus electricity fed back into the grid by solar systems, now down to 75%. This adjustment shifts the financial dynamics, making it less lucrative to export excess solar energy to the grid. Instead, storing this surplus energy in a BESS and utilizing it when energy costs are higher becomes a more financially savvy approach.

The utility of BESS extends beyond merely optimizing the use of solar energy. It offers several additional advantages, such as providing backup power during utility blackouts, mitigating charges associated with demand peaks, and enabling energy arbitrage. Energy arbitrage under this system allows for the charging of BESS not only with excess solar energy but also with cheaper grid energy during low-cost periods. This stored energy can then be used in lieu of more expensive grid power at peak times, effectively reducing reliance on utility-supplied energy. Consequently, NEM 3.0 not only promotes more efficient use of solar energy but also broadens the scope of BESS applications, contributing to a more versatile and resilient energy management strategy.

AECOM



Microgrid Feasibility Study
County of Riverside

Site:
Riverside County Administrative Center
4080 Lemon Street, Riverside, CA 92501

February 2026

Delivering a better world

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Executive Summary

This study appraises the viability and benefits of distributed energy resource implementation scenarios at the subject site. Four scenarios were developed and comparatively analyzed. Key metrics are summarized below.

Case	**Components**	**CAPEX** ($)	**Utility Savings**	**Payback Period** (years)	**GHG Reduction** ($MTCO_2e$/year)
1	PV Only	$727k – $832k (~$499k net w/ ITC)	~$71k/yr	~8	~140
2	PV + BESS	Not justified	Same as Case 1	Same as Case 1	Same as Case 1
3	BESS Only	~$542k	None	No ROI	None
0	Business-as-usual	$0	None	—	None

Note: All values are approximate and based on feasibility-level assumptions.

- **Case 1: Photovoltaic (PV) array –** Introduces on-site generation and provides meaningful utility cost reductions with moderate resilience benefits limited to daytime operation.
- **Case 2: PV + battery energy storage system (BESS)** – Combines on-site generation with energy storage. Evaluated but dismissed, as all PV generation is fully absorbed by on-site loads, leaving no operational margin for battery charging or dispatch.
- **Case 3: BESS only** – Provides limited resilience benefits due to the presence of existing emergency generators sized to serve critical loads.
- **Case 0: Baseline** maintains full reliance on utility power with no additional resilience or emissions benefits.

Based on the comparative analysis detailed in subsequent sections, **Case 1 (PV Only)** is identified as the most suitable and cost-effective path forward. This scenario delivers meaningful utility cost savings, measurable greenhouse gas emission reductions, and a reasonable payback period, while maintaining technical simplicity and avoiding unnecessary capital investment in energy storage systems that provide no functional benefit under current operating conditions.

Recommended Next Steps

1. Advance to a 30% design phase with detailed site and structural assessments
2. Procure vendor-specific quotations to refine cost estimates beyond what is provided in this study
3. Initiate permitting and interconnection applications with Southern California Edison under the current Net Energy Metering tariff (NEM 3.0)
4. Secure federal incentives, specifically the 30% Investment Tax Credit (direct pay), to lower upfront costs
5. Prepare procurement and construction planning, targeting installation within the next budget cycle.

The goal is that with these data-driven microgrid feasibility assessment findings, the County of Riverside can make an informed decision regarding an appropriate resilience-improving investment at the subject site.

Background

Purpose

In recent years, especially within the past decade, the impacts of extreme heat and wildfires have been profound through the Inland Empire. Power service disruptions have been increasing in frequency and severity throughout Riverside County, affecting the availability of essential services and community resources.

In 2023, the Western Riverside Council of Governments (WRCOG) received an award (Grant Agreement OPR23145) from the Adaptation Planning Grant Program of the California Governor's Office of Land Use & Climate Innovation Integrated Climate Adaptation and Resilience Program. This program provides funding to help fill local, regional, and tribal planning needs, provides communities the resources to identify climate resilience priorities, and supports the development of a pipeline of climate-resilient infrastructure projects across the state.

As part of this grant-funded project, the Energy Resilience Plan 2.0, WRCOG commissioned microgrid feasibility studies for its member agencies. These studies serve to provide valuation of a potential microgrid at a community-essential facility, as designated by the member agency.

The site selected for the City of Riverside County is the Riverside County Administrative Center located at 4080 Lemon St, Riverside, CA 92501.

This study presents key insights and findings from the evaluation of distributed energy resource (DER) scenarios, including photovoltaic (PV) array and battery energy storage system (BESS) components, at the subject site. It includes analysis of the site's historic energy demand profile and appraises potential PV array and BESS sizing and siting scenarios accordingly. Notably, the study includes assessment of the generation and storage requirements to support the site's critical loads to enable resilience for a specified number of hours during power service disruptions.

Furthermore, this study outlines the financial implications of self-generation, including estimated cost savings, return on investment (ROI), and potential financing options for the project.

It is important to note that this study serves as a preliminary technical and financial assessment. Its purpose is to provide the County of Riverside with the information to make an informed decision on whether to proceed to next phases of microgrid implementation before committing to detailed engineering design and further investment.

Adaptation Planning Grant Program

As communities in California experience more frequent, prolonged, and severe impacts from climate change, communities and governments at all scales are developing strategies and implementing actions to build a climate-resilient future. However, many jurisdictions, especially under-resourced communities in California, lack the capacity, tools, guidance, and resources to effectively prepare for climate impacts.

The Adaptation Planning Grant Program addresses this capacity gap by providing funding to help fill planning needs, providing communities with the resources to identify climate resilience priorities, and supporting the development of climate resilience projects across the state. The Adaptation Planning Grant Program enables communities to climate risk and adaptation considerations into planning activities and prepare for climate readiness and resilience in the long term.

The Adaptation Planning Grant is part of the Integrated Climate Adaptation and Resiliency Program (ICARP) housed within the Governor's Office of Land Use and Climate Innovation. ICARP advances statewide climate adaptation and resilience by coordinating investments, partnerships, and climate science to ensure people, natural systems, and the built environment are protected, prepared, and thrive in the face of climate change.

Through direct and equity-focused investments and resources, ICARP helps build climate adapted and equitable communities in California, with a focus on solutions that address the impacts of climate change and reduce greenhouse gas emissions. ICARP works to advance these priorities across all levels of government by developing

actionable science and research; providing guidance, tools, and technical assistance; and administering climate resilience-focused grant programs.

Learn more: https://lci.ca.gov/climate/icarp/

Modeling Methodology

This section defines the criteria for sizing the PV array and BESS system components, detailing general parameters, technical requirements, and expected performance criteria.

PV Modeling

1. **Data Inputs**
    - **Solar Resource**: Hourly or sub-hourly irradiance data (e.g., typical meteorological year or on-site measurements)
    - **Site-Specific Factors**: Tilt angle, azimuth, shading analysis, and available roof/ground space
2. **Simulation Approach**
    - Use of HelioScope software to estimate hourly PV production
3. **Sizing Criteria**
    - **Capacity Target**: The sizing criteria are based on 10% of the facility's current annual energy consumption. Due to space constraints at the facility, the proposed PV system offsets approximately 10% of the site's annual energy consumption.
    - **Performance Ratio**: Evaluate Performance Ratio to ensure consistent system output
    - **Energy Production**: Hourly, daily, monthly, and annual PV generation forecasts
    - **Load Matching**: Amount of PV energy that directly offsets site load vs. excess exported to the grid

BESS Modeling

1. **Data Inputs**
    - **Load Profile**: Detailed electricity consumption and demand patterns
    - **PV Production Profile**: From the PV modeling results
    - **Energy Duration for Resilience**: Determine the critical loads that the BESS will support during islanding operations
2. **Operational Modes**
    - **Energy Shifting / Excess PV Storage**: Battery charges when PV output exceeds site demand, discharges when site demand is high.
    - **Resilience (Standalone BESS)**: Sized to support critical loads during outages
3. **Sizing Criteria**
    - **Capacity (kWh)**: Based on required autonomy (energy shifting, peak shaving, or resilience duration)
    - **Max Discharge/Charge Rate (kW)**: Aligned with site load peaks, PV generation surpluses, and emergency power needs
4. **Simulation Approach**
    - Hourly or sub-hourly dispatch modeling to maximize economic benefit (e.g., demand charge reductions or avoided peak rates)

- Incorporate battery round-trip efficiency, self-discharge, and operational constraints (e.g., partial charge strategies)

5. **Output**

   - **Discharge/Charge Profiles**: Hourly modeling of how the battery is utilized
   - **Cost Savings**: Reduction in energy and demand charges or avoided grid cost
   - **Backup Duration**: If sized for resilience, the total hours/days of critical load coverage

Assumptions

AECOM collected facility data through a request for information process. Energy consumption factors and facility characteristics were identified and integrated in analysis. AECOM used these combined datasets to confirm energy utility consumption baselines.

In performing the analysis, AECOM made the following assumptions:

- This report refers to the Riverside County Administrative Center located at 4080 Lemon St, Riverside, CA 92501.
- The monthly and annual electricity consumption is determined using load profile data in the client-provided files " Load_Data." This file contains 35040 load profile data points, which are then consolidated into an 8760 load profile dataset.
- AECOM utilized the Levelized Cost of Energy (LCOE) for the installed cost per watt of PV installations and BESS, as sourced from the National Laboratory of the Rockies (NLR). This data was used to estimate the hypothetical cost of installing the PV array and BESS at the site, as detailed in this report. For an accurate cost estimation, it is necessary to obtain vendor quotes, which are subject to change due to market-dependent time windows. These quotations are typically conducted during the 60% design phase, at which point there is an understanding of the specific equipment ratings and brands to be used.
- This report evaluates the site's existing electrical infrastructure using customer-provided data on the main breaker and bus capacity, as documented in the client-provided file "SLDs." AECOM has assessed whether the existing electrical system can support the proposed PV array and BESS installation. However, as this is a feasibility study, an on-site assessment is required for a definitive determination. A site visit should be conducted during the advanced design phase, typically at the 30% design stage, to confirm site-specific conditions.
- AECOM has estimated the potential PV generation capacity based seemingly available area determinable by publicly available aerial photography. However, a site assessment would be required in later project phases, typically at the 30% design stage, to ensure that the site has the necessary infrastructure for PV array installation. This includes evaluating civil structures, load-bearing capacity, particularly for rooftop installations, and other critical conditions necessary for successful implementation.
- This report uses a regionalized estimate of general production (kWh) to calculate the amount of greenhouse gas emissions avoided through PV generation. The calculation is based on the U.S. EPA Emissions & Generation Resource Integrated Database (eGRID).
- This report clarifies that other charges such as connection fees, required service charges, and taxes remain unchanged. The analysis focuses solely on the bill components directly affected by the installation of PV and BESS under the NEM 3 framework.

AECOM utilized the following tools in conducting the analysis:

- AECOM Internal Tools: Proprietary tools developed by AECOM for analyzing energy patterns and evaluating system performance in simulated environments. These tools are designed to assess energy costs for applications such as peak shaving, energy trading, etc. in DER implementations.
- HelioScope: Web-based software tool used for the design and performance analysis of photovoltaic systems. It combines system layout design with energy simulation, allowing users to model rooftop, ground-mounted, and canopy PV installations. The software factors in module placement, tilt, azimuth, shading, and local weather data to provide accurate estimates of system capacity and expected energy generation.

Site Information

This study is conducted for Riverside County Administrative Center, located at 4080 Lemon St, Riverside, CA 92501. The site currently consumes about **6,542,574 kilowatt-hours (kWh) of electricity per year**.

In terms of electrical infrastructure, the facility is served by a 480/277 volt (V), three-phase, four-wire electrical system centered around a main switchboard rated at 2,500 amperes (A) with a short-circuit rating of 65 kiloampere interrupting capacity (kAIC). The service is designed to support a large, multi-building or multi-functional operation with segmented distribution and coordinated protection suitable for critical facilities.

The total connected electrical load for the site is approximately 1,531 kilowatts (kW). Power is distributed through multiple feeder sections supplying essential operational areas, auxiliary services, and downstream distribution boards. The system architecture supports both normal and emergency operation modes without reliance on a single distribution path.

Emergency and standby power is provided through permanently installed engine-driven generators in the 300–400 kW class at 480/277 V, interconnected through automatic transfer switches rated up to 600 A, four-pole. These transfer systems selectively serve emergency and operationally critical loads rather than the full facility load, ensuring continuity of essential services during utility outages.

The electrical system is constructed with copper conductors throughout, utilizes properly rated step-down transformers for low-voltage control and auxiliary loads, and is supported by a compliant grounding and bonding system. The overall configuration is consistent with NEC requirements for standby and emergency systems and supports reliable, code-compliant operation for critical site functions.

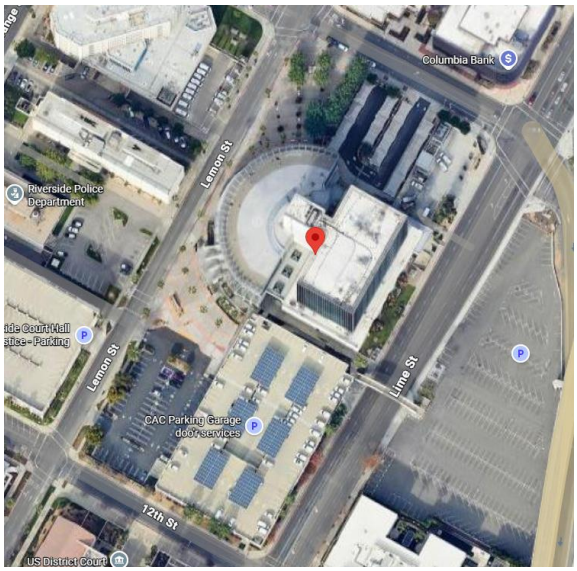


Figure 1. Site Location

Incentive Programs

AECOM has identified three key incentive programs that could benefit the subject site, focusing on renewable energy production and advanced energy storage systems.

The Investment Tax Credit (ITC) and Production Tax Credit (PTC) are federal incentives that reduce the cost of renewable energy projects. ITC offers a tax credit based on a percentage of upfront investment costs, while PTC provides a per-kilowatt-hour credit for electricity generated over time.

Production Tax Credit

Under this initiative, the project is eligible for a tax credit ranging from 0.3 cents to 1.5 cents per installed kWh. The specific value of the credit is determined by several factors, including the project's adherence to certain requirements such as complying with labor standards and using domestic materials.

The PTC program pays for each kilowatt-hour produced over a 10-year period, with government entities receiving the benefit as direct pay instead of a tax credit. For this project, with an estimated 719,483 kWh per year, the best case at 1.5 ¢/kWh would yield about $10,792 annually, totaling around $107,920 over 10 years.

Investment Tax Credit

The City may utilize either the ITC or the PTC, but not both. Because the project has not yet begun construction, the ITC remains the preferred alternative. In this scenario, the project is assumed to be located within a qualifying low-income census tract, enabling eligibility for the additional 10 percent bonus credit.

Under the Low-Income Communities Bonus Credit Program, projects located within a designated low-income community, as defined by the 2016–2020 census tract boundaries in Figure 3, receive an additional 10 percentage points added to the base ITC. This increases the total credit from 30 percent to 40 percent of the eligible project cost.

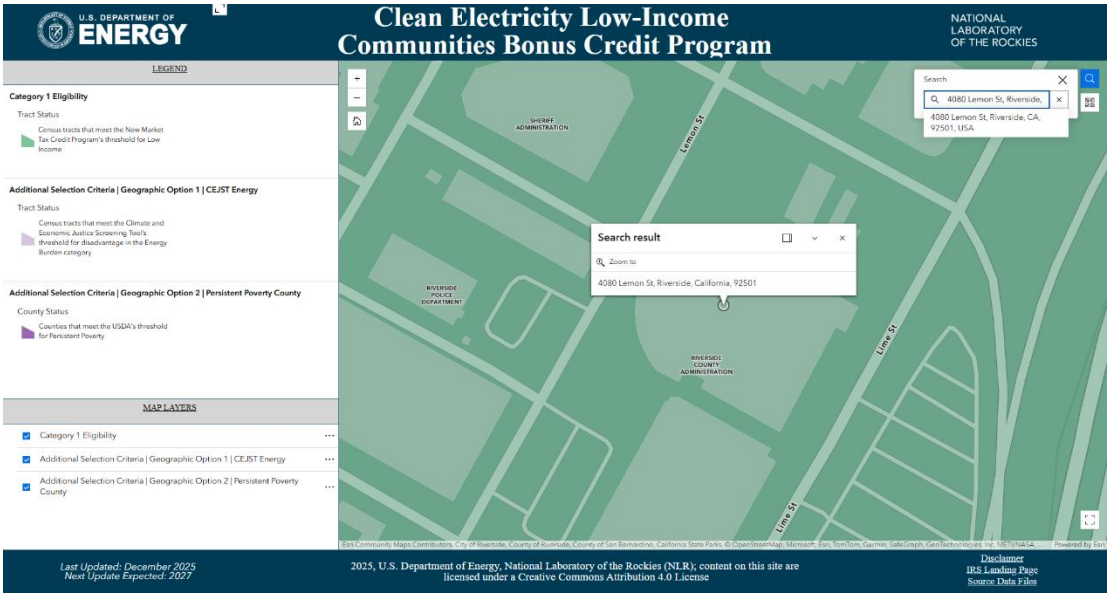


Figure 2. Clean Electricity Low-Income Communities Bonus Credit Program Map

Using NLR's CAPEX range of $1.75–2.00/watt (W) direct current (DC), the proposed 416-kilowatt (kW) DC PV system would cost between $728,000 and 832,000. With a 40 percent ITC, the resulting direct-pay benefit increases to $436,748-499,140, reducing the project's upfront capital requirements accordingly.

Self-Generation Incentive Program

In Case 2, the project site is located within a Disadvantaged Community (DAC), which would normally make it eligible for the SGIP Equity incentive level. Under this program, energy storage systems are incentivized based on an estimated NLR benchmark cost of $450 per kWh, with an Equity incentive rate of $0.85 per watt-hour (Wh) for qualifying projects.

However, in this specific case, SGIP does not apply. The PV system's electricity generation is fully and continuously consumed by the facility's load, leaving no operational margin for a battery system to charge, discharge, or provide grid or resilience services. As a result, no battery capacity is proposed, and although the site is located within a DAC, SGIP incentives are not applicable for this project configuration.

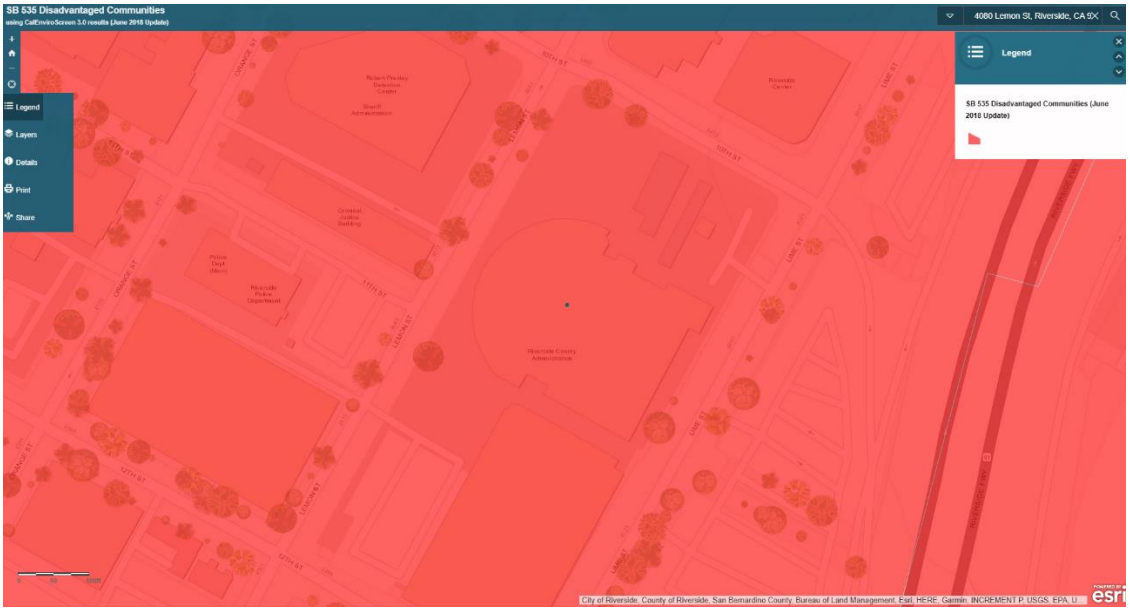


Figure 3. SB 535 Disadvantaged Communities Map

Scenarios & Analysis

Case 0: Current Situation (Baseline)

Tariff & Contract Type

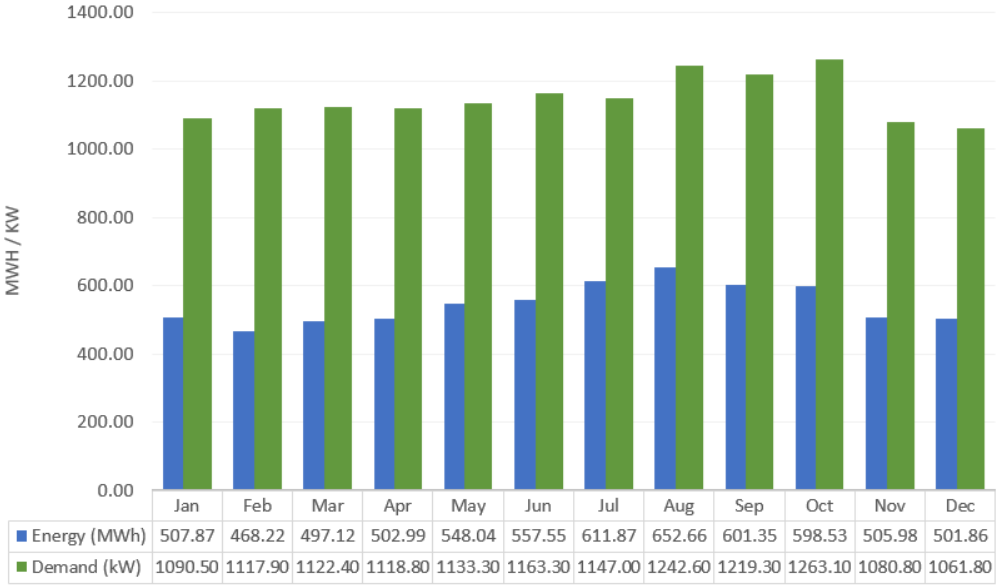
The site is currently served by Riverside Public Utilities under the Schedule TOU – Large General and Industrial Service tariff, which is designed for small to medium commercial customers. This rate structure separates costs into energy charges (based on kilowatt-hours consumed) and demand charges (based on the highest kilowatt demand registered during the billing cycle). In addition, prices vary by time-of-use periods—on-peak, mid-peak, and off-peak—so the timing of energy use significantly affects overall costs.

Being on this tariff means the site's operating expenses are directly tied not only to how much energy is consumed but also to when it is consumed and how high the peak demand reaches.

The tariff cost presents the costs as totals (delivery + bundle). The prices were used as the basis for this study. While they may fluctuate slightly month to month depending on market conditions, these variations are generally minor.

Monthly & Annual Energy Consumption and Demand

The facility currently consumes 6,554,021 kWh annually, with August being the highest month at about 652 MWh and February the lowest at about 468 MWh. In terms of demand, October records the peak at around 1,263 kW, while November is the lowest at about 1,080 kW. The following graph presents this historical data for the 2024–2025 period.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Energy (MWh)	507.87	468.22	497.12	502.99	548.04	557.55	611.87	652.66	601.35	598.53	505.98	501.86
Demand (kW)	1090.50	1117.90	1122.40	1118.80	1133.30	1163.30	1147.00	1242.60	1219.30	1263.10	1080.80	1061.80

Figure 4. Historic Site Energy Profile

Monthly & Annual Energy Costs

site currently spends about $838,983 per year in energy and demand cost, with approximately $609,876 in energy costs and $229,107 in demand charges, based on tariff Large General and Industrial Service simulation. For this analysis, we are focusing only on energy and demand costs, as these are the components directly impacted by the installation of a PV system.

Case 1: PV Only

Installed Capacity & Location

The PV system for the site was sized to offset approximately 10% of current consumption, However, in this specific case, The PV system's electricity generation is fully and continuously consumed by the facility's load, leaving no operational margin for excess PV energy. The placement areas for the PV installation were identified according to customer requirements. The system capacity is estimated at 416 kW DC, with an expected annual production of about 719,483 kWh.

Figure 6.1 and 6.2 present the modeled energy production throughout the year, and Figures 7.1 and 7.2 depict the respective PV installation areas on the site.

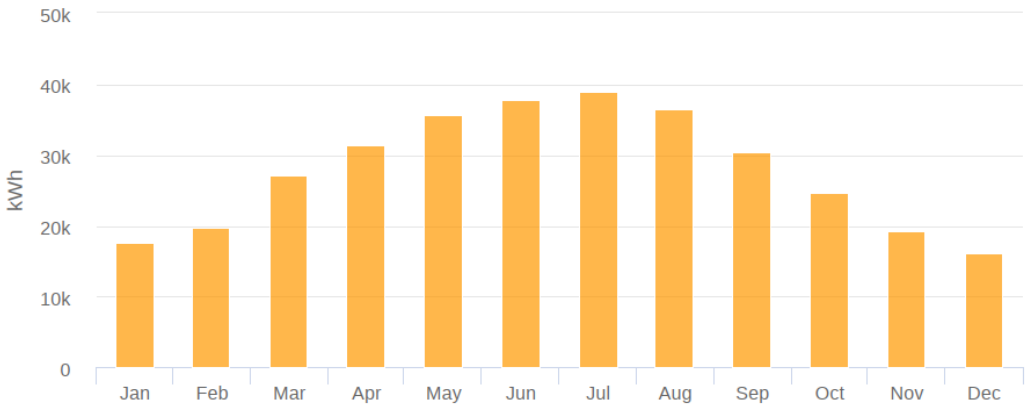


Figure 5.1 Modeled PV Production Area 1

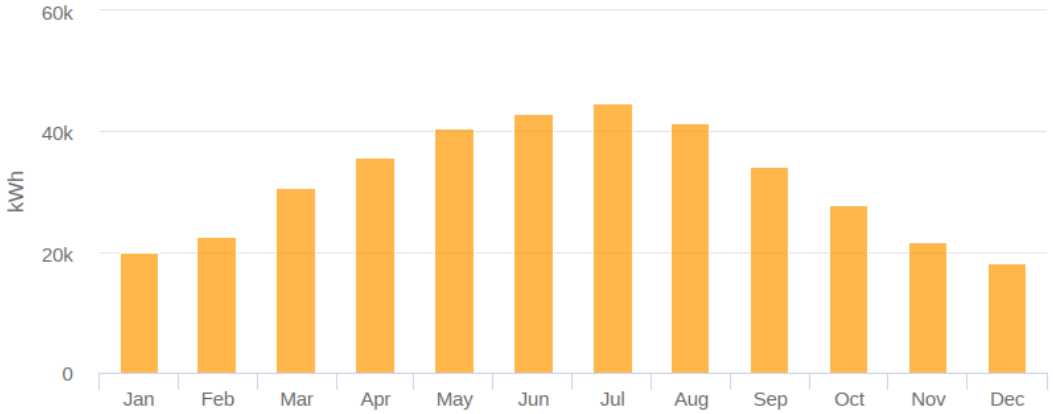


Figure 6.2 Modeled PV Production Area 2

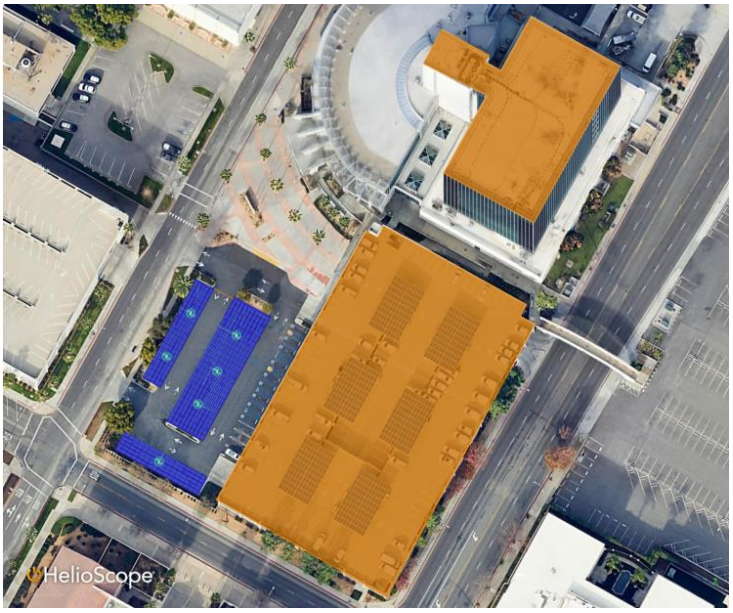


Figure 7.1 Modeled PV Installation Area 1

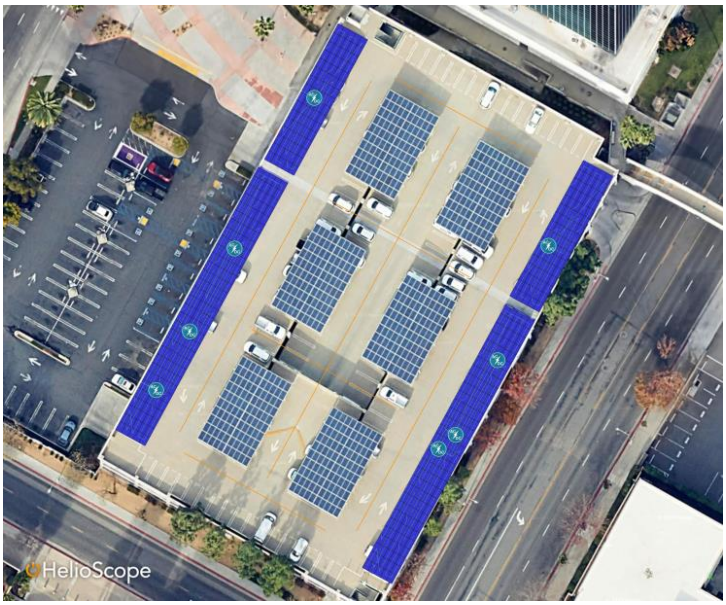


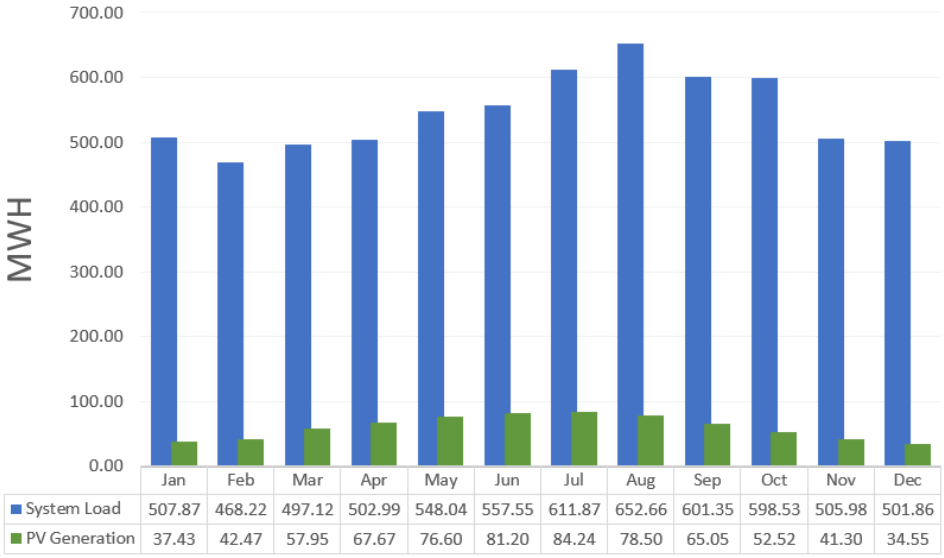
Figure 8.2 Modeled PV Installation Area 2

Modeled PV Production

The modeled PV system is projected to generate an average of **59,957 kWh per month**, with an estimated **annual production of 719,483 kWh**.

This scenario doesn't include a BESS, so the excess energy produced need be exported to the utility, which requires entering a Net Energy Metering (NEM) contract with the utility service provider. Under the currently available NEM tariff, NEM 3.0, exported electricity is credited at dynamic rates that vary by month, hour of day, and weekday, ranging from as low as $0.01/kWh during midday hours to over $1.00/kWh during peak evening hours in high-demand months like August and September. This study has calculated projected benefits from this arrangement.

Figure 8 compares historic monthly energy consumption and modeled PV generation. Not all solar energy will be consumed on-site, as excess daytime production may exceed demand and be exported to the grid, while nighttime demand cannot be covered since there is no generation after sunset and no battery to store the excess in this scenario.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
System Load	507.87	468.22	497.12	502.99	548.04	557.55	611.87	652.66	601.35	598.53	505.98	501.86
PV Generation	37.43	42.47	57.95	67.67	76.60	81.20	84.24	78.50	65.05	52.52	41.30	34.55

Figure 9. Modeled PV Output vs. Site Demand

Capital Expenditures

Based on NLR benchmark CAPEX values for commercial rooftop solar, the estimated cost to install 416 kW DC PV system in Riverside County, California falls in the range of **$1.75 to $2.00 per watt DC**. This translates to a total investment of **approximately $727,913 – 831,900 for the complete system**.

These figures include **typical equipment, installation, and soft costs**, reflecting average market conditions for commercial-scale projects. Actual costs may vary slightly depending on site-specific conditions such as roof structure, permitting, interconnection requirements, and labor. However, the NLR benchmarks provide a reliable basis for estimating the capital cost of a system of this size and type in the region.

Operating Expenses

According to NLR's 2024 benchmark data, the annual operations and maintenance (OPEX) cost for commercial rooftop PV systems is about $19 per kW DC. For a 416 kW DC system, this translates to an **estimated yearly OPEX of roughly $7,903** covering routine maintenance, monitoring, and related operational expenses.

Economic Metrics

The analysis shows that installing a PV system at the site under NEM3 provides measurable financial benefits by offsetting both energy and demand charges. Without solar, the facility currently spends about $838,983 annually on utility costs. With the PV system in operation, the energy cost is reduced to approximately $540,696 per year, while the demand cost drops to about $227,065 per year. In addition, the system generates excess electricity during the

day that cannot be fully consumed on-site. Since the site consumes all the energy produced by the PV system, no net energy is exported to the grid; therefore, there is no benefit under the NEM 3.0 framework.

Taken together, these reductions and export credits bring the facility's total utility bill down to **$767,762 per year**, achieving an **overall savings of about 8%** compared to current expenses

Payback Period and Return on Investment

The financial analysis shows that without PV, the facility spends approximately $838,983 per year on utility costs. With a 416 kW DC PV system installed, the annual cost is reduced to about $767,762, resulting in yearly savings of roughly $71,221. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system is estimated at $831,900, but with the 30 percent ITC direct pay, the net investment is reduced to approximately $499,140. In addition, the system carries an annual OPEX of $7,903, which slightly offsets the yearly savings. Taking these factors into account, the project generates a net benefit of about $71,221 minus $7,903 per year after OPEX. This results in a simple payback period of approximately 8 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross Savings ($)	Net Savings after OPEX ($)	Cumulative Cash Flow ($)
1	71,221	63,318	-435,822
2	73,358	65,218	-370,604
3	75,559	67,174	-303,429
4	77,826	69,190	-234,239
5	80,160	71,265	-162,974
6	82,565	73,403	-89,571
7	85,042	75,605	-13,965
8	87,593	77,874	63,909
9	90,221	80,210	144,118
10	92,928	82,616	226,735
15	107,729	95,775	678,514
20	124,887	111,029	1,202,249

Table 1. Return on Investment w/ 3% Inflation: Case 1

Technical Feasibility

The facility electrical distribution operates at 480/277 V, 3-phase, 4-wire and is served by a main switchboard designated MSB with a 2500 A bus rating and 65 kAIC interrupting rating.

A 416 kW PV system interconnected at 480 V, 3-phase produces a full-output inverter current of 416,000 W divided by (sqrt(3) times 480 V) which equals 500 A alternating current (AC). As a continuous source, the required output circuit ampacity and interconnection OCPD is 1.25 times 500 A which equals 625 A, requiring a 700 A class PV backfeed breaker or equivalent rated PV interconnection device.

Under NEC 705 busbar loading (120 percent rule), the maximum allowable load-side PV backfeed on a 2500 A bus with a 2500 A main overcurrent device is (1.20 times 2500 A) minus 2500 A which equals 500 A. The required PV

backfeed ampacity is 625 A, resulting in a quantified noncompliance shortfall of 125 A versus the NEC 705 allowable backfeed limit.

Corrective action is required to achieve code compliance: implement a supply-side interconnection in accordance with NEC 705 using a dedicated, service-rated PV tap ahead of the MSB main with a 700 A PV disconnect and OCPD, or upgrade the MSB bus and associated main section to a bus rating of at least (2500 A plus 625 A) divided by 1.20 which equals 2604 A, requiring a practical upgrade to the next standard bus class (for example 3000 A or 3200 A) to accommodate a 700 A PV interconnection on the load side.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 719,483 kWh per year. Using the U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:

- Carbon dioxide (CO_2): 308,273 (pounds) lbs (139.8 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 309,365 lbs (140.3 metric tons) avoided annually
- Nitrogen oxides (NOx): 239 lbs (108 kg) avoided annually
- Sulfur dioxide (SO_2): 14.4 lbs (6.5 kg) avoided annually

Case 2: PV + BESS

Given available area onsite for PV installations, only approximately 10 percent of the facility's total annual energy consumption can be offset by PV array(s). As a result, all PV generation would fully consumed by on-site loads, and no excess energy would be available to charge a battery or shift energy into higher-cost periods. Under these conditions, the addition of a BESS provides no operational or economic benefit, making further analysis of a PV plus BESS configuration infeasible for this scenario.

CASE 3: BESS Only

Critical Load Identification

Based on the facility classification as an Operator Center, the drawings clearly indicate the presence of an emergency generator, automatic transfer switching, and a segregated emergency distribution system serving life-safety and mission-critical functions. Under NEC 700, NEC 701, NFPA 110, and NFPA 72, the required critical loads include egress and emergency illumination, fire alarm and notification systems, emergency communications and dispatch functions, security and access control systems, and legally required standby power for operational continuity. From the electrical architecture shown, these systems represent an estimated 25 percent of the total connected load, resulting in a total critical load of 382.5 kW.

Battery Capacity & Infrastructure

The battery energy storage system capacity is derived directly from the emergency load and required duration. A critical load of 382.5 kW over 4 hours results in a required energy capacity of 1,530 kWh, with a required discharge power rating of 100 kW. The drawings indicate that emergency loads are served through dedicated transfer equipment and emergency distribution, implying that any BESS integration would need to be connected on the emergency side of the ATS or through a parallel emergency bus. Bus ratings, breaker interrupting capacity, and feeder ampacity must accommodate the additional source without violating existing equipment limits

Capital Expenditures

Using cost benchmarks published by the National Laboratory of the Rockies (NLR), the estimated capital cost (CAPEX) for a 1,550 kWh / 100 kW battery energy storage system is approximately $542,500 under ITC program. This figure includes the battery cabinets, inverter/PCS, microgrid controller with ATS, installation, protections, and engineering.

Operating Expenses

The expected operating cost (OPEX) is about $6,200 per year, also based on NLR reference values. This covers preventive maintenance, monitoring software, and NFPA 110 testing requirements. Battery replacement is typically required after 10–12 years of service.

Return on Investment & Qualitative Benefits

While a conventional financial return cannot be directly applied to this case, the value of a BESS for an Operator Center is framed in terms of resilience, reliability, and compliance. Such systems are designed to ensure uninterrupted operation of life-safety and mission-critical equipment during extended utility outages. The benefits include maintaining operational continuity, reducing safety risks, and ensuring compliance with NFPA 110, NFPA 70, and NFPA 72.

However, for this particular facility, the drawings clearly show an existing standby generator system serving emergency loads. If the installed generator capacity already exceeds the 382.5 kW critical load requirement, the incremental resilience provided by a BESS may be limited relative to cost. In this scenario, justification typically shifts from technical necessity to redundancy preferences, policy objectives, or long-term reliability planning

Technical Considerations

Integration of a BESS into the existing electrical architecture requires verification of emergency bus capacity, compliance with the 120 percent load-side interconnection rule where applicable, and confirmation that breakers and feeders can accommodate an additional power source. The drawings indicate clear separation between normal and emergency systems, which must be maintained through proper ATS coordination. A detailed short-circuit and protection coordination study, transfer sequence validation between generator and BESS, and evaluation of UL 9540A fire propagation requirements are necessary to ensure safe and compliant integration within the existing emergency power framework

Decision Matrix and Scenario Comparison

In order to determine the most appropriate scenario for the site, four scenarios were developed and analyzed: business as usual (Case 0), installing a PV system only (Case 1), installing PV with a BESS (Case 2), and installing a BESS only (Case 3). Each case was evaluated in terms of resilience value, capital and operating expenditures, energy savings, payback period, and technical feasibility. The decision matrix summarizes the comparative performance of these options.

Criteria	Case 0: Baseline	Case 1: PV Only	Case 2: PV + BESS	Case 3: BESS Only
Resilience Benefit	None	Limited (daytime only)	High (self-consumption, some coverage)	High (but redundant due to existing 125 kW generator)
CAPEX ($)	0	$727,913 – $831,900 (before ITC) ~$499,140 net with ITC	Not applicable (BESS infeasible)	~$542k
OPEX ($/yr)	Current $24k	~7,903	N/A	~$6,200
Annual Utility Bill ($)	~$838,983	~$767,762	N/A	~$838,983 (no reduction)
Annual Savings ($)	–	~$71,221 gross ~$63,318 net after OPEX	N/A	Minimal (non-financial)
Payback Period	–	~8 years	N/A	No ROI
GHG Reduction	None	~140 $MTCO_2e$ avoided annually	N/A	None
Technical Feasibility	Already in place	Feasible with required NEC 705 supply-side interconnection	N/A	Technically feasible but unnecessary

Table 2. Scenario Comparison

Conclusion

Based on the comparative analysis, **Case 1 (PV Only)** emerges as the most appropriate scenario for the site. While Case 2 (PV + BESS) is often attractive in facilities with excess solar generation or peak-shifting opportunities, the current site conditions do not support meaningful battery operation. The proposed PV system is sized to offset approximately 10 percent of annual energy consumption and its generation is fully absorbed by on-site loads, leaving no operational margin to charge or dispatch a BESS. As a result, adding storage would significantly increase capital costs without delivering proportional economic or resilience benefits.

Case 3 (BESS Only) was also evaluated but ultimately dismissed. The facility is already equipped with permanently installed emergency generators capable of serving the identified critical load of approximately 382.5 kW. Under these conditions, a standalone BESS would be largely redundant from a resilience perspective and would not provide a justifiable financial return. Any additional resilience value would be incremental and policy-driven rather than technically or economically required.

Therefore, Case 1 provides the most balanced solution by delivering measurable energy cost savings, meaningful greenhouse gas emission reductions, and a reasonable payback period, while avoiding unnecessary system complexity and infrastructure upgrades. This option aligns with the site's existing electrical configuration, operational needs, and long-term cost-control objectives.

Summary of Strategy & Benefits

The recommended strategy focuses on installing a rooftop photovoltaic system sized to offset approximately 10 percent of the facility's annual energy consumption. This approach delivers the following benefits:

- **Resilience Support**: While not designed as a backup power source, on-site solar generation enhances overall energy independence and reduces reliance on the utility during normal operating conditions.
- **Economic Savings**: Reduces annual utility costs by approximately **$71,000 per year**, lowering total utility expenditures from about **$838,983 to $767,762** through direct energy and demand charge offsets.
- **Financial Feasibility**: With an estimated net capital cost of approximately **$499,140 after ITC**, the project achieves a **simple payback of roughly 8 years**, followed by long-term, inflation-protected savings over the remaining system life.
- **Environmental Impact**: Offsets approximately **140 metric tons of CO_2e emissions annually**, contributing to regional greenhouse gas reduction and sustainability goals.
- **Technical Simplicity**: Requires limited electrical modifications, with NEC 705 compliance achieved through a supply-side interconnection or equivalent corrective measure, avoiding major distribution system upgrades.
- **Operational Practicality**: Minimizes operational and maintenance complexity by avoiding battery systems that offer no functional benefit under current load and generation conditions.

Next Steps

To advance the project, the following steps are recommended:

1. **Detailed Design & Site Assessment:** Conduct a 30% design phase evaluation, including structural assessment of the roof, electrical interconnection details, and shading analysis
2. **Vendor Quotations:** Obtain updated vendor quotes for PV system equipment, installation, and interconnection to refine cost estimates beyond NLR benchmarks
3. **Permitting & Interconnection:** Coordinate with Southern California Edison (SCE) to complete the interconnection study and ensure compliance with NEM 3 tariff rules
4. **Finalize Incentive Applications:** Submit applications for the 30% ITC (direct pay) to secure federal funding and reduce upfront capital cost
5. **Procurement & Installation:** Issue RFPs for procurement and construction, selecting qualified contractors with experience in municipal PV installations
6. **Commissioning & Monitoring:** Upon installation, perform commissioning tests, integrate the system with monitoring platforms, and establish an operations and maintenance (O&M) plan to ensure reliable long-term performance

Appendix

Incentive Programs

This section outlines how the incentive programs function and provides relevant information about them. Specific application of these programs to presented scenarios is explored in previous sections.

Inflation Reduction Act

The Inflation Reduction Act of 2022 stands as a significant piece of legislation designed to strengthen the United States' commitment to fighting climate change by making considerable investments in renewable energy. A key feature of the Inflation Reduction Act is its financial incentives, namely the Investment Tax Credit (ITC) and the Production Tax Credit (PTC), which aim to accelerate the adoption of renewable energy technologies.

The ITC allows for a significant tax credit for investments in renewable energy technologies, including solar panels and wind turbines, directly reducing the upfront cost of these systems. This makes renewable projects more financially viable and attractive to investors and consumers alike. On the other hand, the PTC provides a per-kilowatt-hour tax relief for the production of energy from renewable sources, incentivizing the operation and expansion of renewable energy facilities.

Notably, Inflation Reduction Act programs have been subject to change in recent legislation. Presented here are active opportunities as of the time of the report.

Production Tax Credit

The Production Tax Credit (PTC) within the framework of the Inflation Reduction Act offers considerable financial incentives for renewable energy projects, primarily designed to decrease the federal income tax liability based on the electricity produced per kilowatt-hour.

The PTC directly reduces the federal income tax for taxable entities. Furthermore, for non-taxable entities such as local governments, educational institutions, or nonprofit organizations, the PTC allows these credits to be monetized, facilitating their involvement in renewable energy initiatives. This provision is applicable for projects that become operational between January 1, 2023, and December 31, 2032, providing a broad window for planning and implementation.

Projects located in designated low-income energy communities receive further incentives. The PTC is structured to be claimable annually for a decade from the start date of operations of the qualifying renewable system, providing long-term financial support. This current structure of the PTC is set to continue through the end of 2024. Starting from January 1, 2025, the credit system will transition to a technology-neutral format, broadening the scope to include a wider array of technologies and fostering a more inclusive approach to renewable energy incentives.

As of the date of this report, the program is still active but solar projects must have “begun construction” by July 4, 2026.

The City project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

Investment Tax Credit

The Investment Tax Credit (ITC) established under the Inflation Reduction Act offers a powerful incentive for deploying renewable energy technologies by providing a reduction in federal tax liability. This reduction is calculated as a percentage of the capital investment made in eligible energy systems. Taxpayers can apply the ITC to their federal income tax for the year the technology is installed, significantly decreasing their tax burden.

Starting January 1, 2023, special provisions enable tax-exempt entities such as local governments and nonprofits to receive direct payments equivalent to the value of the credit. This arrangement improves the liquidity and financial feasibility of renewable projects for these organizations. The scope of eligible technologies under the ITC is broad, encompassing solar panels, wind turbines, fuel cells, and other renewable energy systems.

As of 2025, the Investment Tax Credit (ITC) for solar projects is set at 30% of the eligible costs, encompassing both the equipment and installation expenses. This rate is scheduled to decrease to 26% in 2033 and further to 22% in 2034. Systems rated under 1 megawatt (MW) qualify for the full 30% without having to comply with additional requirements; larger systems will only receive the full amount if they meet specific labor requirements. These include paying prevailing wages to workers during construction and using apprentices to perform a portion of the total construction hours (15% after 2023). Bonus credits are available based on site location, e.g. low-income communities.

The ITC is set to continue delivering these benefits at its current rate until 2032, contingent upon meeting the specific project criteria laid out in the act. Looking ahead, post-2024, the ITC will transition to a technology-neutral system, which will be applicable to all zero-emissions technologies, reflecting a shift towards a more inclusive and adaptable approach to supporting renewable energy development.

HHZP project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

As of the date of this report, the program is still active but critical deadlines for project eligibility and complete operability are quickly approaching in 2026 and 2027, respectively.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) offers financial incentives to non-residential customers of utility Company to encourage the adoption of energy storage systems. These systems help businesses prepare for power outages that may occur due to weather, emergencies, or other unforeseen events. The SGIP funding is authorized through 2024, with incentives structured to decrease over time as funding milestones are reached or as more participants enter the program.

Non-residential customers have access to three types of SGIP rebates: General Market, Equity, and Equity Resilience. Furthermore, SGIP incentives are significantly higher for vulnerable or disadvantaged communities through the Equity and Equity Resilience categories.

Incentives are typically paid upfront for residential systems upon project completion and site verification, while nonresidential systems may receive half upfront with the balance paid based on the system's performance over time. Eligibility for SGIP incentives extends to residential, commercial, industrial, agricultural, and municipal customers of specific utilities including Pacific Gas & Electric, Southern California Edison, SoCalGas, San Diego Gas & Electric, and those managed by the Center for Sustainable Energy.

To be eligible for this rebate, a facility must satisfy two conditions: firstly, it must fall under the category of a government agency, educational institution, non-profit organization, or small business. Secondly, it must fulfill at least one of the following requirements: be located in a Disadvantaged Community (DAC), be situated in a census tract where the Median Household Income of the Statewide Median Income or be situated in California Indian Country.

On the other hand, the equity resilience rebate offers a rate, covering a percentage of the cost of an average energy storage system. To qualify for this rebate, a facility must meet certain requirements. Firstly, it must have experienced two or more utility Public Safety Power Shut-offs (PSPS), or it should be located in a Tier 2 or 3 High Fire Threat District (HFTD) and serve customers in DACs or Low Income Communities. Secondly, it must fulfill at least one of the following additional criteria:

- Be a police station, fire station, emergency response provider, emergency operations center, 911 call center, medical facility, private and public natural gas, electric, water, wastewater, or flood facility, jail or prison, utility-designated PSPS assistance center, cooling center, homeless shelter.
- Be a grocery store, supermarket, or corner store with less than $15 million in annual gross receipts.

- Be an Independent Living Center or a Food Bank.

Modeling Assumptions

The modeling conducted for this feasibility study was based on standard industry benchmarks, available site data, and conservative assumptions to ensure realistic projections. The following key assumptions were applied:

1. **Energy Consumption Baseline** – Historical hourly load data (8,760 points) from the facility was consolidated to represent a typical annual profile. This served as the reference for sizing PV and BESS systems.
2. **PV System Costs** – Capital expenditure (CAPEX) and operations and maintenance (OPEX) values were derived from the National Laboratory of the Rockies (NLR) 2024–2025 benchmarks for commercial rooftop systems. PV CAPEX was assumed at $1.75–$2.00/Wdc, with OPEX at ~$19/kW-year.
3. **BESS Costs** – Battery energy storage CAPEX was modeled using NLR 2025 benchmarks at ~$350/kWh. OPEX was assumed at ~$40/kW-year, covering maintenance, monitoring, and lifecycle management.
4. **ITC Incentives** – A 30% Investment Tax Credit (direct pay) was assumed, reducing upfront project cost. No additional low-income or disadvantaged community adders were included, since the site does not qualify.
5. **Performance Parameters** –
    - PV generation modeled with HelioScope using site tilt, azimuth, and shading factors.
    - Battery modeled with 90% round-trip efficiency and daily cycling where applicable.
    - Energy inflation rate of 3% annually applied to utility costs.
6. **Utility Tariff** – The analysis used the most recent Southern California Edison tariff, **TOU-GS-2 Option D**, as published in the file *ELECTRIC_SCHEDULES_TOU-GS-2_2025*. It was assumed under the current **NEM 3** framework. Exported PV energy was valued at ~25% of retail rate. Since tariff structures and prices are subject to future changes, the financial outcomes presented here should be viewed as indicative estimates rather than fixed projections.
7. **Infrastructure** – Electrical interconnection feasibility was preliminarily evaluated using customer-provided single-line diagrams. Minor breaker adjustment (600 A to 500 A) was assumed to comply with NEC 705.12 120% busbar rule for PV backfeed.
8. **Environmental Impact** – Greenhouse gas (GHG) reduction estimates were calculated using EPA eGRID emission factors for the CAMX subregion, applied to modeled PV generation.

Disclaimer: These figures are rough estimates intended for feasibility-level evaluation. If more precise values are required, additional detail must be developed through site-specific engineering, vendor quotations, and utility coordination during the advanced design phase.

Net Energy Metering

Net Energy Metering (NEM) in California is a billing arrangement that allows residential and commercial customers who generate their own electricity, primarily through solar photovoltaic (PV) systems, to receive credit for the surplus energy they contribute to the grid. This system is designed to incentivize the use of renewable energy sources by offsetting the cost of electricity consumption with the energy produced by these installations.

Under NEM, when a solar system generates more electricity than is consumed, the excess energy is sent back to the utility grid, and the customer earns credits. These credits can then be used to offset the cost of energy drawn from the grid when the solar system isn't producing enough to meet the customer's demand, like during nighttime or cloudy days. The rules, rates, and credits under NEM can vary over time, with different iterations such as NEM 1, 2, and the latest NEM 3, each having specific regulations and compensation structures for solar energy production and exchange.

The transition from NEM 2 to NEM 3 in California, which was effective on April 14, 2023, introduced significant changes in the net metering policies for utility customers with photovoltaic (PV) systems. These changes impact

several aspects, particularly the economics of energy arbitrage between PV system owners and the utility. Here's a summary of the key changes:

1) **Reduction in Export Rates:** Under NEM 3, there's a substantial reduction in the rates for excess electricity exported onto the grid by solar systems. This rate has been reduced by approximately 75%, thereby lowering the overall savings for home solar systems and increasing the payback period. This change is a shift from the traditional one-to-one offset of net metering policies, where the price of a kWh of electricity pushed onto the grid was equal to the price of a kWh pulled off the grid.
2) **Implementation of Electrification Rates:** Customers enrolling in NEM 3 are required to use electrification rates instead of regular Time-of-Use (TOU) rates. These electrification rates feature higher on-peak charges and lower off-peak charges, along with a fixed charge of $15 per month. The peak rate period remains from 4 pm to 9 pm.
3) **Export Compensation Based on Avoided Cost Calculator (ACC):** Export compensation under NEM 3 is determined by California's ACC, with specific export rates for every combination of Month, Hour, and Weekday or Weekend. The export value is lowest in the middle of the day when solar energy is abundant on the grid and highest during peak summer demand periods. Notably, the export rates are significantly lower than retail rates during the hours when PV systems are most productive (10 am – 3 pm). To maintain the financial viability of solar PV systems, customers in PG&E and SCE service territories receive an adder on top of the ACC rate, ranging between 2.2 and 9 cents depending on location and customer class.
4) **Shift to a Cost Avoidance System:** NEM 3 introduces a cost avoidance system for exported electricity. This system pays customers the lowest amount a company can pay under the Public Utility Regulatory Policies Act of 1978 (PURPA), which is significantly less than the typical retail rate. This results in customers receiving, on average, 75% less for the electricity they sell back to the grid, with rates varying by month and by hour.
5) **Grandfathering NEM 2 under NEM 3:** Under the recent NEM 3 policy in California, existing customers with a photovoltaic (PV) system installed under NEM 2 can retain the benefits and terms of their NEM 2 agreement, a process known as "grandfathering." However, these customers are restricted from replacing or adding capacity to their PV systems if they wish to maintain their NEM 2 status, as any significant modifications would require transitioning to the terms of NEM 3.

The Net Energy Metering (NEM) 3.0 policy introduces transformative changes, particularly enhancing the value of utilizing Battery Energy Storage Systems (BESS) for owners of solar power systems. A significant aspect of NEM 3.0 is the reduction in compensation rates for surplus electricity fed back into the grid by solar systems, now down to 75%. This adjustment shifts the financial dynamics, making it less lucrative to export excess solar energy to the grid. Instead, storing this surplus energy in a BESS and utilizing it when energy costs are higher becomes a more financially savvy approach.

The utility of BESS extends beyond merely optimizing the use of solar energy. It offers several additional advantages, such as providing backup power during utility blackouts, mitigating charges associated with demand peaks, and enabling energy arbitrage. Energy arbitrage under this system allows for the charging of BESS not only with excess solar energy but also with cheaper grid energy during low-cost periods. This stored energy can then be used in lieu of more expensive grid power at peak times, effectively reducing reliance on utility-supplied energy. Consequently, NEM 3.0 not only promotes more efficient use of solar energy but also broadens the scope of BESS applications, contributing to a more versatile and resilient energy management strategy.

AECOM



Microgrid Feasibility Study
City of Corona

Site:
Ysmael Villegas Community Center

February 2026

Delivering a better world

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Executive Summary

This study appraises the viability and benefits of distributed energy resource implementation scenarios at the subject site. Four scenarios were developed and compared, with key metrics summarized below:

Case	Components	CAPEX ($)	Utility Savings (kW)	Utility Savings ($)	Payback Period (years)	GHG Reduction ($MTCO_2e$)
1	PV	~$225k (~$135k with ITC)	~52% reduction	~$10,714	~14	~38.6
2	PV + BESS	~$135k (PV after ITC, BESS covered by SGIP)	~80% reduction	~$16,730	~10	~38.6
3	BESS	~$38k	—	—	—	—
0	Business-as-usual	—	—	—	—	—

Note: All values are approximate and subject to final design and incentive approval.

- **Case 1: Photovoltaic (PV) array –** Introduces on-site renewable generation that offsets a large portion of the facility's annual electricity consumption and reduces both energy and demand charges.
- **Case 2: PV plus battery energy storage system (BESS) –** Maximizes on-site utilization of solar generation. Excess daytime production is stored and dispatched during evening and high-value periods, significantly reducing grid reliance and overall electricity costs.
- **Case 3: BESS only** – Provides backup capability for critical loads and improves resilience but does not significantly reduce utility costs.
- **Case 0: Business-as-usual** – Maintains current utility dependence with no additional resilience or cost reduction benefits.

Considering the technical, financial, and operational results of the analysis, Case 2 (PV + BESS) provides the most advantageous overall solution. This configuration reduces annual electricity costs from approximately $20,755 to about $4,025 while improving energy autonomy and optimizing solar energy utilization under the NEM 3 framework.

Considering the above, detailed more in Sections 3 and 4, this study concludes that the PV array (Case 2) scenario is the most suitable and cost-effective path forward, striking a balance between resilience capabilities, technical feasibility, and financial performance.

Recommended Next Steps

1. Advance to a 30% design phase with detailed site and structural assessments
2. Procure vendor-specific quotations to refine cost estimates beyond what is provided in this study
3. Initiate permitting and interconnection applications with Southern California Edison under the current Net Energy Metering tariff (NEM 3.0)
4. Secure federal incentives, specifically the 30% Investment Tax Credit (direct pay), to lower upfront costs
5. Prepare procurement and construction planning, targeting installation within the next budget cycle.

The goal is that with these data-driven microgrid feasibility assessment findings, the City of Riverside can make an informed decision regarding an appropriate resilience-improving investment at the subject site.

Background

Purpose

In recent years, especially within the past decade, the impacts of extreme heat and wildfires have been profound through the Inland Empire. Power service disruptions have been increasing in frequency and severity throughout Riverside County, affecting the availability of essential services and community resources.

In 2023, the Western Riverside Council of Governments (WRCOG) received an award (Grant Agreement OPR23145) from the Adaptation Planning Grant Program of the California Governor's Office of Land Use & Climate Innovation Integrated Climate Adaptation and Resilience Program. This program provides funding to help fill local, regional, and tribal planning needs, provides communities the resources to identify climate resilience priorities, and supports the development of a pipeline of climate-resilient infrastructure projects across the state.

As part of this grant-funded project, the Energy Resilience Plan 2.0, WRCOG commissioned microgrid feasibility studies for its member agencies. These studies serve to provide valuation of a potential microgrid at a community-essential facility, as designated by the member agency.

The site selected for the City of Riverside is the Ysmael Villegas Community Center located at 3091 Esparanza Street, Riverside, CA 92522.

This study presents key insights and findings from the evaluation of distributed energy resource (DER) scenarios, including photovoltaic (PV) array and battery energy storage system (BESS) components, at the subject site. It includes analysis of the site's historic energy demand profile and appraises potential PV array and BESS sizing and siting scenarios accordingly. Notably, the study includes assessment of the generation and storage requirements to support the site's critical loads to enable resilience for a specified number of hours during power service disruptions.

Furthermore, this study outlines the financial implications of self-generation, including estimated cost savings, return on investment (ROI), and potential financing options for the project.

It is important to note that this study serves as a preliminary technical and financial assessment. Its purpose is to provide the City of Riverside with the information to make an informed decision on whether to proceed to next phases of microgrid implementation before committing to detailed engineering design and further investment.

Adaptation Planning Grant Program

As communities in California experience more frequent, prolonged, and severe impacts from climate change, communities and governments at all scales are developing strategies and implementing actions to build a climate-resilient future. However, many jurisdictions, especially under-resourced communities in California, lack the capacity, tools, guidance, and resources to effectively prepare for climate impacts.

The Adaptation Planning Grant Program addresses this capacity gap by providing funding to help fill planning needs, providing communities with the resources to identify climate resilience priorities, and supporting the development of climate resilience projects across the state. The Adaptation Planning Grant Program enables communities to climate risk and adaptation considerations into planning activities and prepare for climate readiness and resilience in the long term.

The Adaptation Planning Grant is part of the Integrated Climate Adaptation and Resiliency Program (ICARP) housed within the Governor's Office of Land Use and Climate Innovation. ICARP advances statewide climate adaptation and resilience by coordinating investments, partnerships, and climate science to ensure people, natural systems, and the built environment are protected, prepared, and thrive in the face of climate change.

Through direct and equity-focused investments and resources, ICARP helps build climate adapted and equitable communities in California, with a focus on solutions that address the impacts of climate change and reduce greenhouse gas emissions. ICARP works to advance these priorities across all levels of government by developing

actionable science and research; providing guidance, tools, and technical assistance; and administering climate resilience-focused grant programs.

Learn more: https://lci.ca.gov/climate/icarp/

Modeling Methodology

This section defines the criteria for sizing the PV array and BESS system components, detailing general parameters, technical requirements, and expected performance criteria.

PV Modeling

1. **Data Inputs**
    - **Solar Resource**: Hourly or sub-hourly irradiance data (e.g., typical meteorological year or on-site measurements)
    - **Site-Specific Factors**: Tilt angle, azimuth, shading analysis, and available roof/ground space
2. **Simulation Approach**
    - Use of HelioScope software to estimate hourly PV production
3. **Sizing Criteria**
    - **Capacity Target**: The sizing criteria are based on 110% of the facility's current annual energy consumption. This approach aims to fully offset the facility's energy usage with the PV array while incorporating an additional 10% capacity to accommodate future demand growth. However, the final system capacity is constrained by the area designated as available by the client.
    - **Performance Ratio**: Evaluate Performance Ratio to ensure consistent system output
    - **Energy Production**: Hourly, daily, monthly, and annual PV generation forecasts
    - **Load Matching**: Amount of PV energy that directly offsets site load vs. excess exported to the grid

BESS Modeling

1. **Data Inputs**
    - **Load Profile**: Detailed electricity consumption and demand patterns
    - **PV Production Profile**: From the PV modeling results
    - **Energy Duration for Resilience**: Determine the critical loads that the BESS will support during islanding operations
2. **Operational Modes**
    - **Energy Shifting / Excess PV Storage**: Battery charges when PV output exceeds site demand, discharges when site demand is high.
    - **Resilience (Standalone BESS)**: Sized to support critical loads during outages
3. **Sizing Criteria**
    - **Capacity (kWh)**: Based on required autonomy (energy shifting, peak shaving, or resilience duration)
    - **Max Discharge/Charge Rate (kW)**: Aligned with site load peaks, PV generation surpluses, and emergency power needs
4. **Simulation Approach**
    - Hourly or sub-hourly dispatch modeling to maximize economic benefit (e.g., demand charge reductions or avoided peak rates)

- Incorporate battery round-trip efficiency, self-discharge, and operational constraints (e.g., partial charge strategies)

5. **Output**

- **Discharge/Charge Profiles**: Hourly modeling of how the battery is utilized
- **Cost Savings**: Reduction in energy and demand charges or avoided grid cost
- **Backup Duration**: If sized for resilience, the total hours/days of critical load coverage

Assumptions

AECOM collected facility data through a request for information process. Energy consumption factors and facility characteristics were identified and integrated in analysis. AECOM used these combined datasets to confirm energy utility consumption baselines.

In performing the analysis, AECOM made the following assumptions:

- This report refers to the Ysmael Villegas Community Center, located at 3091 Esparanza Street, Riverside, CA 92522.
- The monthly and annual electricity consumption is determined using load profile data derived from 12 months of utility billing data provided by the client. As the client did not provide an 8760 load profile, AECOM applied an internal load reconstruction algorithm to simulate an equivalent 8760 hourly load profile for the analysis.
- AECOM utilized the Levelized Cost of Energy (LCOE) for the installed cost per watt of PV installations and BESS, as sourced from the National Laboratory of the Rockies (NLR). This data was used to estimate the hypothetical cost of installing the PV array and BESS at the site, as detailed in this report. For an accurate cost estimation, it is necessary to obtain vendor quotes, which are subject to change due to market-dependent time windows. These quotations are typically conducted during the 60% design phase, at which point there is an understanding of the specific equipment ratings and brands to be used.
- This report evaluates the site's existing electrical infrastructure using customer-provided data on the main breaker and bus capacity, as documented in the client-provided electrical plans. AECOM has assessed whether the existing electrical system can support the proposed PV array and BESS installation. However, as this is a feasibility study, an on-site assessment is required for a definitive determination. A site visit should be conducted during the advanced design phase, typically at the 30% design stage, to confirm site-specific conditions.
- AECOM has estimated the potential PV generation capacity based on the client-identified available area, as documented in the client-provided file "VillegasPark-no go areas." However, a site assessment is required in later project phases, typically at the 30% design stage, to ensure that the site has the necessary infrastructure for PV array installation. This includes evaluating civil structures, load-bearing capacity, particularly for rooftop installations, and other critical conditions necessary for successful implementation.
- This report uses a regionalized estimate of general production (kWh) to calculate the amount of greenhouse gas emissions avoided through PV generation. The calculation is based on the U.S. EPA Emissions & Generation Resource Integrated Database (eGRID).
- This report clarifies that other charges such as connection fees, required service charges, and taxes remain unchanged. The analysis focuses solely on the bill components directly affected by the installation of PV and BESS under the NEM 3 framework.

AECOM utilized the following tools in conducting the analysis:

- AECOM Internal Tools: Proprietary tools developed by AECOM for analyzing energy patterns and evaluating system performance in simulated environments. These tools are designed to assess energy costs for applications such as peak shaving, energy trading, etc. in DER implementations.
- HelioScope: Web-based software tool used for the design and performance analysis of photovoltaic systems. It combines system layout design with energy simulation, allowing users to model rooftop, ground-mounted, and canopy PV installations. The software factors in module placement, tilt, azimuth, shading, and local weather data to provide accurate estimates of system capacity and expected energy generation.

Site Information

This study is conducted for the Ysmael Villegas Community Center, located at 3091 Esparanza Street, Riverside, CA 92522. The site currently consumes about **179,040 kWh per year**,

In terms of electrical infrastructure, the site is equipped with a main service panel identified as “MSA” rated 400 amps, 120/240 volts, single-phase, three-wire, 60 Hz. The service is utility-fed from a pole riser into a meter/main section and then into a distribution section with a 400 A main copper bus. The distribution serves multiple branch circuits for sports field lighting poles A1, A2, B1, B2, C1, and C2, as well as separate security lighting circuits and associated lighting control equipment.

The drawings show individual pole loads of approximately 3.4 kW for poles A1 and A2, 11.9 kW for poles B1 and B2, and 6.8 kW for poles C1 and C2, plus security lighting totaling 3.0 kW. The total connected load shown in the load summary is 47.2 kW, equivalent to about 182.5 amps at 120/240 V, 1-phase, which the drawing notes indicate is within the capacity of the new service. The largest branch conductors shown in the conductor schedule are up to No. 2 AWG copper, with copper grounding conductors and raceways as scheduled. The grounding scheme includes bonding of the neutral bus, grounding bus, service raceway, structural steel where available, metal water pipe when applicable, and driven ground rods as indicated by the grounding details and switchgear notes. The drawings also note that the series rating of the main switchboard must be greater than the available fault current, but a specific kAIC value is not explicitly listed on the sheets provided.



Figure 1. Site Location

Incentive Programs

AECOM has identified three key incentive programs that could benefit the subject site, focusing on renewable energy production and advanced energy storage systems.

The Investment Tax Credit (ITC) and Production Tax Credit (PTC) are federal incentives that reduce the cost of renewable energy projects. ITC offers a tax credit based on a percentage of upfront investment costs, while PTC provides a per-kilowatt-hour credit for electricity generated over time.

Production Tax Credit

Under this initiative, the project is eligible for a tax credit ranging from 0.3 cents to 1.5 cents per installed kWh. The specific value of the credit is determined by several factors, including the project's adherence to certain requirements such as complying with labor standards and using domestic materials.

The PTC program pays for each kilowatt-hour produced over a 10-year period, with government entities receiving the benefit as direct pay instead of a tax credit. For this project, with an estimated 198,700 kWh per year, the best case at 1.5 ¢/kWh would yield about $2,981 annually, totaling around $29,805 over 10 years.

Investment Tax Credit

The City may utilize either the ITC or the PTC, but not both. Because the project has not yet begun construction, the ITC remains the preferred alternative. In this scenario, the project is assumed to be located within a qualifying low-income census tract, enabling eligibility for the additional 10 percent bonus credit.

Under the Low-Income Communities Bonus Credit Program, projects located within a designated low-income community, as defined by the 2016–2020 census tract boundaries in Figure 3, receive an additional 10 percentage points added to the base ITC. This increases the total credit from 30 percent to 40 percent of the eligible project cost.

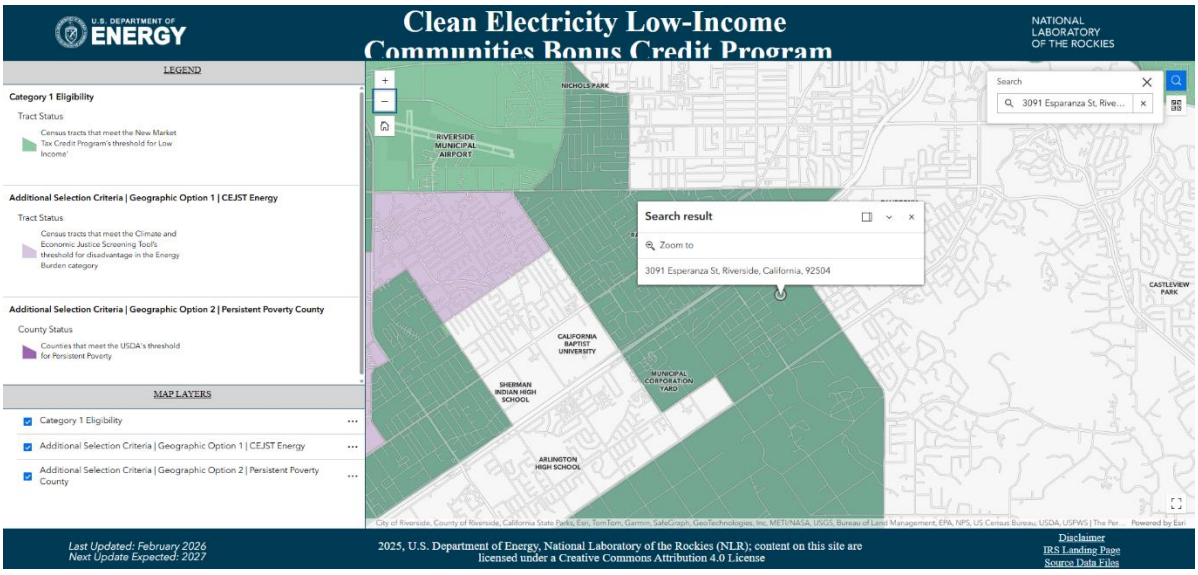


Figure 2. Clean Electricity Low-Income Communities Bonus Credit Program Map

Using NLR's CAPEX range of 1.75–2.00 USD/Wdc, the proposed 112.8 kWdc PV system would cost between 197,400 and 225,600 USD. With a 40 percent ITC, the resulting direct-pay benefit increases to 78,960-90,240 USD, reducing the project's upfront capital requirements accordingly.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) is California's primary incentive designed to reduce the upfront cost of energy storage systems. The program has three levels:

- **General Market:** For projects located outside Disadvantaged Communities (DAC). Typical incentive: $0.10/Wh.
- **Equity (DAC):** For projects located within a DAC. Incentive: $0.85/Wh.
- **Equity Resilience**: For critical facilities within a DAC and in PSPS or high fire-risk zones. Incentive: $1.00/Wh.

In Case 2, the project is located within a DAC, so it qualifies for the Equity level. Using an NLR-based cost of $450/kWh, the 350-kWh battery would cost approximately $157,500. At the Equity incentive rate of $0.85/Wh, the available support would total $297,500, which is sufficient to fully cover the system cost within SGIP's allowable limits.

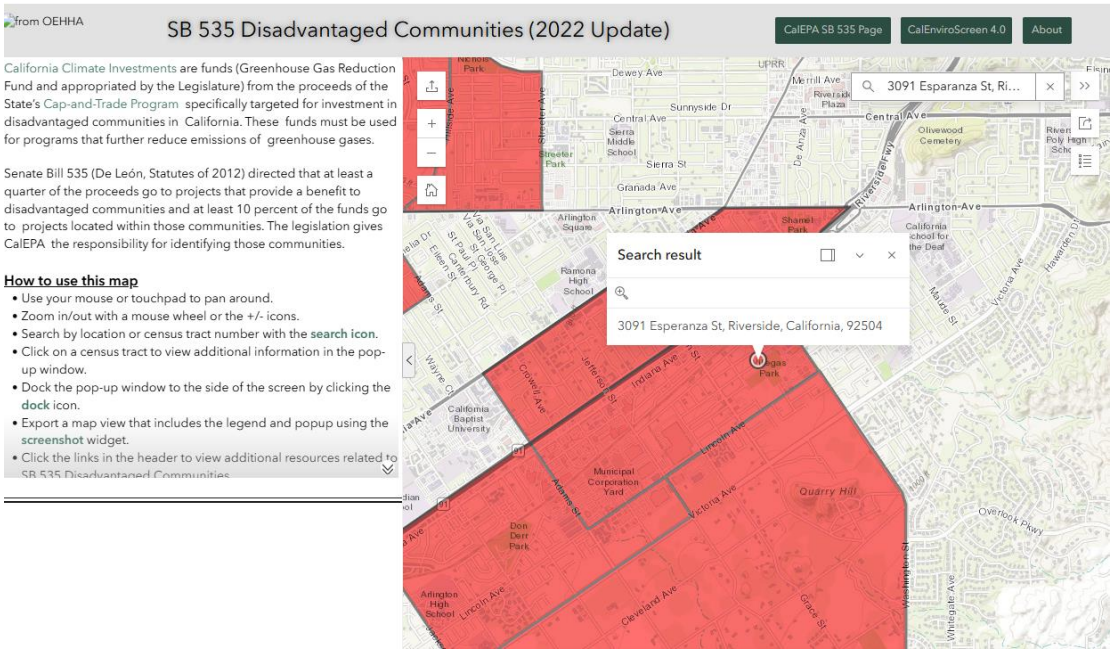


Figure 3. SB 535 Disadvantaged Communities Map

Scenarios & Analysis

Case 0: Current Situation (Baseline)

Tariff & Contract Type

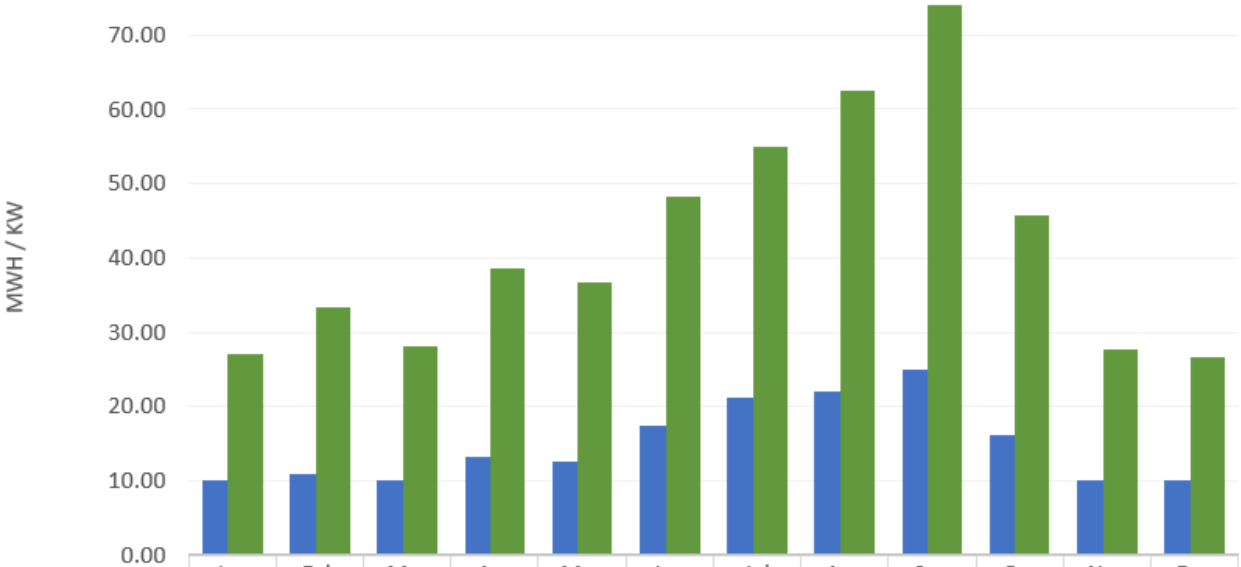
The site is currently served by Riverside Public Utilities under the Electric tariff, which is designed for small to medium commercial customers. This rate structure separates costs into energy charges (based on kilowatt-hours consumed) and demand charges (based on the highest kilowatt demand registered during the billing cycle). In addition, prices vary by time-of-use periods—on-peak, mid-peak, and off-peak—so the timing of energy use significantly affects overall costs.

Being on this tariff means the site's operating expenses are directly tied not only to how much energy is consumed but also to when it is consumed and how high the peak demand reaches.

The tariff cost presents the costs as totals (delivery + bundle). The prices were used as the basis for this study. While they may fluctuate slightly month to month depending on market conditions, these variations are generally minor.

Monthly & Annual Energy Consumption and Demand

The facility currently consumes 179,040 kWh annually, with September being the highest month at about 24,960 kWh and January the lowest at about 27,120 kWh. In terms of demand, September records the peak at around 74 kW, while January is the lowest at about 27 kW. The following graph presents this historical data for the 2024–2025 period.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Energy (MWh)	10.08	10.96	10.08	13.36	12.56	17.52	21.12	22.08	24.96	16.16	10.08	10.08
Demand (kW)	27.12	33.31	28.16	38.61	36.75	48.26	55.01	62.43	74.05	45.80	27.71	26.67

Figure 4. Historic Site Energy Profile

Monthly & Annual Energy Costs

The site currently spends about $20,755 per year in energy and demand cost, with approximately $14,466 in energy costs and $6,288 in demand charges, based on tariff Electric simulation. For this analysis, we are focusing only on energy and demand costs, as these are the components directly impacted by the installation of a PV system.

Case 1: PV Only

Installed Capacity & Location

The PV system for the site was sized to offset approximately 100% of current consumption, with the goal of fully offsetting present usage while reserving about 10% additional capacity for future growth. The placement areas for the PV installation were identified according to customer requirements. The system capacity is estimated at 112.8 kW direct current (DC), with an expected annual production of about 179,040 kWh.

Figure 6 presented the modeled energy production throughout the year, and Figure 7 identifies the designated PV installation areas on the site.

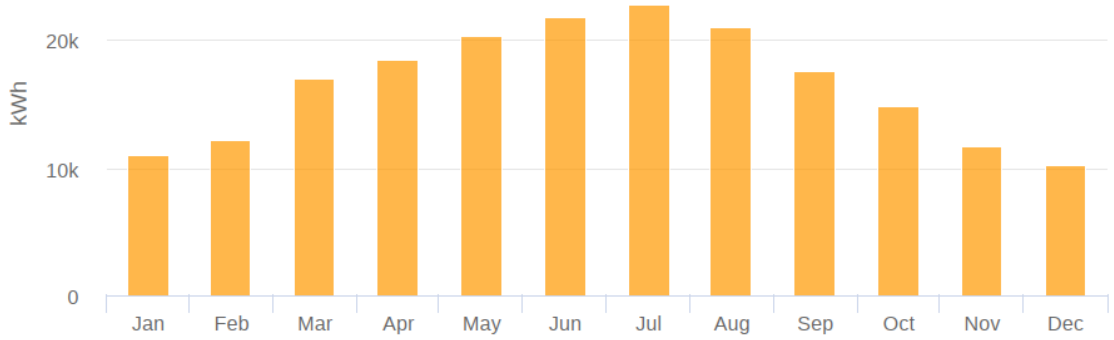


Figure 5. Modeled PV Production



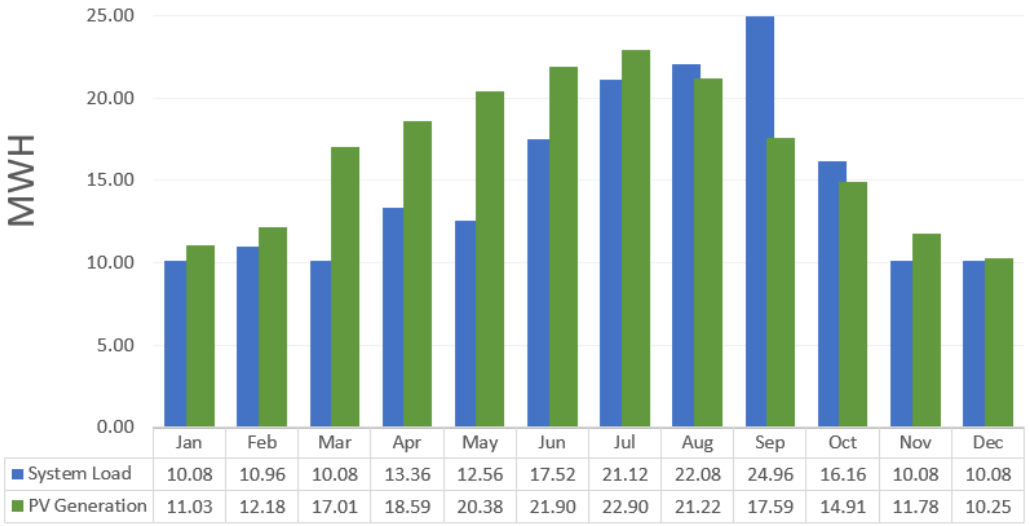
Figure 6. Modeled PV Installation Areas

Modeled PV Production

The modeled PV system is projected to generate an average of **16,558 kWh per month**, with an estimated **annual production of 198,700 kWh**.

This scenario doesn't include a BESS, so the excess energy produced need be exported to the utility, which requires entering a Net Energy Metering (NEM) contract with the utility service provider. Under the currently available NEM tariff, NEM 3.0, exported electricity is credited at dynamic rates that vary by month, hour of day, and weekday, ranging from as low as $0.01/kWh during midday hours to over $1.00/kWh during peak evening hours in high-demand months like August and September. This study has calculated projected benefits from this arrangement.

Figure 8 compares historic monthly energy consumption and modeled PV generation. Not all solar energy will be consumed on-site, as excess daytime production may exceed demand and be exported to the grid, while nighttime demand cannot be covered since there is no generation after sunset and no battery to store the excess in this scenario.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
System Load	10.08	10.96	10.08	13.36	12.56	17.52	21.12	22.08	24.96	16.16	10.08	10.08
PV Generation	11.03	12.18	17.01	18.59	20.38	21.90	22.90	21.22	17.59	14.91	11.78	10.25

Figure 7. Modeled PV Output vs. Site Demand

Capital Expenditures

Based on NLR benchmark CAPEX values for commercial rooftop solar, the estimated cost to install a 112.8 kW DC PV system in Riverside County, California falls in the range of **$1.75 to $2.00 per watt DC**. This translates to a total investment of **approximately $197,400 to $225,600 for the complete system**.

These figures include **typical equipment, installation, and soft costs**, reflecting average market conditions for commercial-scale projects. Actual costs may vary slightly depending on site-specific conditions such as roof structure, permitting, interconnection requirements, and labor. However, the NLR benchmarks provide a reliable basis for estimating the capital cost of a system of this size and type in the region.

Operating Expenses

According to NLR's 2024 benchmark data, the annual operations and maintenance (OPEX) cost for commercial rooftop PV systems is about $19 per kW-DC. For a 112.8 kW DC system, this translates to an **estimated yearly OPEX** of **roughly $2,143**, covering routine maintenance, monitoring, and related operational expenses.

Economic Metrics

The analysis shows that installing a PV system at the site under NEM3 provides measurable financial benefits by offsetting both energy and demand charges. Without solar, the facility currently spends about $20,755 annually on utility costs. With the PV system in operation, the energy cost is reduced to approximately $7,416 per year, while the demand cost drops to about $4,897 per year. In addition, the system generates excess electricity during the day that cannot be fully consumed on-site. Under NEM3 rules, this exported energy represents an additional benefit of roughly $2,272 annually.

Taken together, these reductions and export credits bring the facility's total utility bill down to **$10,714 per year**, achieving an **overall savings of about 52%** compared to current expenses

Payback Period and Return on Investment

The financial analysis shows that without PV, the facility spends approximately $20,755 per year on utility costs. With a 112 kW DC PV system installed, the annual cost is reduced to about $10,041, resulting in yearly savings of roughly $10,714. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system is estimated at $225,600, but with the 40 percent ITC direct pay, the net investment is reduced to approximately $135,360. In addition, the system carries an annual OPEX of $2,143, which slightly offsets the yearly savings. Taking these factors into account, the project generates a net benefit of about $10,714 minus $2,143 per year after OPEX. This results in a simple payback period of approximately 14 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross Savings ($)	Net Savings after OPEX ($)	Cumulative Cash Flow ($)
1	10,714	8,571	-126,789
2	11,035	8,828	-117,962
3	11,366	9,093	-108,869
4	11,707	9,365	-99,503
5	12,058	9,646	-89,857
6	12,420	9,936	-79,921
7	12,793	10,234	-69,687
8	13,176	10,541	-59,147
9	13,572	10,857	-48,289
14	15,733	12,586	11,082
15	16,205	12,964	24,046
20	18,787	15,029	94,938

Table 1. Return on Investment w/ 3% Inflation: Case 1

Technical Feasibility

The existing service equipment is a 120/240 V, single-phase, 3-wire main service panel with a 400 A main breaker and a 400 A bus. Under NEC 705.12, a 400 A bus with a 400 A main breaker permits a maximum aggregate bus loading of 480 A, which limits the allowable photovoltaic backfeed breaker to 80 A. 12.8 kW photovoltaic system interconnected at 240 V single-phase produces 470 A of AC output current. Applying the 125% continuous source requirement, the minimum photovoltaic overcurrent device rating is 588 A, which requires a 600 A standard breaker.

erconnection is not compliant as a load-side breaker connection to the existing 400 A panel. The allowable NEC 705 backfeed capacity is 80 A, while the required photovoltaic breaker is 600 A, resulting in a 520 A breaker shortfall. On an output current basis, the photovoltaic source exceeds the allowable backfeed capacity by 390 A. Corrective action shall be either a supply-side interconnection ahead of the existing 400 A main service disconnect or replacement of the service equipment with a bus structure not less than 1000 A and a revised main and photovoltaic breaker arrangement that satisfies NEC 705 bus loading limits

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 198,700 kWh per year. Using the U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:

- Carbon dioxide (CO_2): 85,123.08 lbs (38.61 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 85,441.00 lbs (38.76 metric tons) avoided annually
- Nitrogen oxides (NO_x): 65.97 lbs (29.92 kg) avoided annually
- Sulfur dioxide (SO_2): 3.97 lbs (1.80 kg) avoided annually

Case 2: PV + BESS

System Components

This scenario assumes the same PV array described in Case 1 and a BESS sized for surplus PV production. The day with the highest energy surplus in our simulation occurred on May 30, during which the PV system produced 795 kWh, the site consumed 379 kWh, and the resulting surplus was 416 kWh. For size the BESS, we ran several iterations based on the available surplus energy and applied an algorithm that simulates the charge and discharge cycles of one year. This techno-financial analysis indicates that the optimal BESS capacity is approximately 350 kWh.

This simulation factor ensures that even under variations in production or demand, all possible excess solar energy generated during the day can be stored. The stored energy is then available for use at night or during periods when PV production does not fully cover the site's demand.

By doing so, most of the units of solar energy produced on-site are consumed daily by the facility, preventing as little as possible any export to the grid.

Modeled Energy Flows

By installing a 350 kWh battery, we ensure that all the energy generated on-site is consumed by the facility itself. The charge and discharge profile of the battery is designed so that any PV surplus during the day is immediately stored in the battery rather than exported to the grid. Later, if the site demand exceeds the PV generation while there is still energy stored in the battery, the deficit is supplied from the battery.

This operational strategy minimizes or even eliminates consumption from the utility, since the PV and battery combination is prioritized to cover the load at all times. On an annual basis, the system is expected to produce slightly more energy than the site requires, leaving a surplus of around 10%, but this excess is negligible in terms of the overall utility bill.

Capital Expenditures

According to NLR benchmark data, the capital expenditure (CAPEX) for a commercial-scale112.8 kW DC rooftop PV system in Riverside, California is estimated at $135,360 under ITC incentive, based on installation costs of $1.75–2.00 per watt DC.

For storage, NLR's 2025 cost projections indicate a CAPEX of $450 per kWh for the high-cost scenario. Applying this benchmark to a commercial-scale 350 kWh battery system represents an investment of roughly $157,500 and under the SGIP program this amount can be fully covered, effectively funding 100% of the BESS system

Together, the combined CAPEX for the PV and BESS systems is estimated at 135,360 representing the expected upfront investment for a commercial solar-plus-storage project of this size.

Operating Expenses

According to NLR benchmark data, the annual operations and maintenance (OPEX) cost for a commercial-scale 112.8 kW DC rooftop PV system is estimated at $2,143 USD.

NLR data indicates an operating cost of approximately $4 per kW-year. For a commercial-scale 350 kWh battery system, this results in an annual OPEX of about $1,400.

Together, the combined OPEX for the PV and BESS systems is approximately $3,543 per year, covering routine maintenance, monitoring, and system management.

Economic Metrics

The analysis shows that installing a commercial-scale PV system paired with a 350 kWh battery under NEM 3 provides strong financial advantages by allowing a substantial portion of the solar energy produced by the PV system to be consumed on-site.

In several cases, PV production exceeds the facility's demand, and the surplus can be stored in the BESS for later use. However, without a battery system, the facility cannot absorb all of this excess energy, since any unused

generation must be consumed the moment it is produced. This unused energy would otherwise need to be exported to the utility grid, where under current NEM rules it would be compensated at only about 25 percent of the retail electricity rate. Given that time-of-use pricing makes stored energy far more valuable during high-cost periods, it becomes financially preferable to store surplus solar rather than sell it.

Without a BESS, exporting this excess would generate $2,272 but the facility would still face an annual utility cost of 10,041 By contrast, installing the BESS reduces grid reliance and allows the facility to consume nearly all of its solar production during higher-priced periods, resulting in a significantly lower annual utility bill of $ 4,025

To remain conservative, this analysis assumes that 10% of annual energy costs remain due to efficiency losses, imperfect alignment of PV output and site load, and seasonal variability.

It is important to note that other charges — such as connection fees, requisite charges, and taxes — remain unaffected. This analysis focuses only on those bill components directly impacted by the installation of PV and BESS under the NEM 3 framework.

Payback Period and Return on Investment

The financial analysis shows that without PV + BESS, the facility spends approximately $20,755 per year on utility costs. With a 112.8 kW DC PV system and 350 kWh BESS system installed, the annual cost is reduced to about $ 4,025 resulting in yearly savings of roughly $16,730. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system under ITC and SGIP incentives is estimated at $135,360. In addition, the system carries an annual OPEX of $ 3,453 Taking these factors into account, the combined system generates a net benefit of about 13,277 per year after OPEX. This results in a simple payback period of approximately 10 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross-Savings ($)	Net-Savings after OPEX ($)	Cumulative Cash Flow ($)
1	16,729	13,186	-122,174
2	17,231	13,582	-108,592
3	17,748	13,989	-94,602
4	18,281	14,409	-80,193
5	18,829	14,841	-65,352
6	19,394	15,287	-50,065
7	19,976	15,745	-34,320
8	20,575	16,218	-18,103
9	21,192	16,704	-1,399
10	21,828	17,205	15,806
15	25,305	19,945	109,891
20	29,335	23,122	218,961

Table 2. Return on Investment w/ 3% Inflation: Case 2

Technical Feasibility

The one line diagram shows an existing main service panel “MSA” rated 120/240 VAC, 1-phase, 3-wire, with a 400 A main copper bus. Based on that configuration, a new 90 kW AC PV interconnection at 240 V would produce approximately 375 A of output current, which is a very large addition relative to the existing service equipment.

A load-side PV backfeed connection is not practical at this panel. Under the NEC 705.12 120% bus limit, a 400 A bus allows a maximum combined main breaker and backfeed breaker total of 480 A, so with a 400 A service main, only 80 A of PV backfeed capacity would be permitted.

Because the proposed PV output is far above that limit, the existing main service panel cannot accept this system through a simple breaker addition. The required PV breaker and conductors would substantially exceed the allowable load-side interconnection capacity of the panel.

The BESS also cannot be assumed to connect on the existing load side without further upgrades. The one line diagram does not show a dedicated spare section or a defined new storage interconnection point, so the storage system would require its own reviewed point of connection, disconnecting means, protection, and conductor routing.

The recommended solution is to interconnect the new PV and BESS on the supply side of the existing main service equipment, or to install new service equipment specifically sized for distributed energy resources. This avoids overloading the existing 400 A bus and provides a code-compliant path for larger generation and storage capacity.

As part of the upgrade, the service entrance arrangement, utility metering section, overcurrent protection, grounding and bonding, and conductor sizes must be reviewed and modified as required for the new source connections. A full protection and coordination review is also required to confirm interrupting ratings, breaker duties, and safe operation of the revised service.

In summary, the existing one line supports interconnection only if a new supply-side connection or new service equipment is added. A direct load-side breaker connection at the existing 400 A panel is not feasible for a 90 kW PV system, and the BESS will also require a dedicated interconnection and protection design.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 198,700 kWh per year. Using the U.S. EPA’s Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:

- Carbon dioxide (CO_2): 85,123.08 lbs (38.61 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 85,441.00 lbs (38.76 metric tons) avoided annually
- Nitrogen oxides (NO_x): 65.97 lbs (29.92 kg) avoided annually
- Sulfur dioxide (SO_2): 3.97 lbs (1.80 kg) avoided annually

CASE 3: BESS Only

Critical Load Identification

For a community center, NEC 700 and NFPA 101 require emergency power only for life-safety systems such as egress illumination and fire alarm notification. NFPA 72 requires secondary power for fire alarm operation during loss of utility power. The electrical drawings show primarily lighting distribution circuits serving exterior lighting systems and associated control circuits, with no indication of medical equipment, mission-critical communications, or continuous-process loads. Therefore, the emergency classification is limited to life-safety lighting and fire alarm functions. Based on these requirements and the facility electrical scope, the emergency load is estimated at 21.3 kW.

AECOM have evaluated the single line diagrams provided by the client and identified the critical loads that must be supported by an emergency backup system. The selection of these critical loads is based on generally accepted standards and codes such as the NFPA 70 (National Electrical Code), NFPA 110 (Standard for Emergency and Standby Power Systems), and NFPA 72 (National Fire Alarm and Signaling Code), which require that life-safety systems, fire detection, alarms, communication, and essential facility functions be maintained during a power outage.

Required Backup Duration

For a Community Center, maintaining continuous operation of alarm systems, emergency communications, lighting, and fuel dispensing is essential. According to NFPA 110 (Section 4.2 and 7.12.1), emergency power supply systems (EPSS) must provide a minimum of 2 hours of operation at full rated load

Battery Capacity & Infrastructure

The emergency system capacity is derived from the calculated emergency demand of 21.3 kW and the 4-hour backup duration. This results in an energy requirement of approximately 85 kWh with a discharge capability of 21.3 kW. The battery system must therefore support continuous output equal to the emergency load while maintaining sufficient stored energy for the full duration. Integration requires connection on the emergency distribution side through a dedicated automatic transfer switch or equivalent transfer mechanism to ensure separation between normal and emergency circuits. The switchboard and downstream feeders must be verified for available bus capacity, breaker ratings, and coordination with the emergency distribution branch.

Capital Expenditures

Using cost benchmarks published by the National Laboratory of the Rockies (NLR), the estimated capital cost (CAPEX) for a 85-kWh / 22-kW battery energy storage system is approximately $38,250.

Operating Expenses

The expected operating cost (OPEX) is about $340 per year, also based on NLR reference values. This covers preventive maintenance, monitoring software, and NFPA 110 testing requirements. Battery replacement is typically required after 10–12 years of service.

Return on Investment & Qualitative Benefits

While a conventional financial return (ROI) cannot be directly applied to this case, the value of a BESS for a Community Center is framed in terms of resilience, reliability, and compliance. Such systems are designed to ensure uninterrupted operation of life-safety and mission-critical equipment during extended utility outages. The benefits include maintaining operational continuity, reducing safety risks, and ensuring compliance with NFPA 110, NFPA 70, and NFPA 72.
However, for this particular facility, the justification for a BESS must be evaluated against the existing backup assets. If the generator capacity already exceeds the critical load requirement, the incremental resilience provided by the BESS may be limited relative to cost. In these situations, the decision typically shifts from technical necessity to redundancy preferences, policy considerations, or long-term reliability planning.

Technical Considerations

Integration of a battery system with the existing electrical distribution requires verification of switchboard bus capacity and breaker ratings to ensure compliance with the 120 percent load-side interconnection limitation when connected on the distribution bus. The emergency circuits must remain electrically separated from normal loads through an automatic transfer mechanism or dedicated emergency panelboard. Additional engineering studies are required including short-circuit analysis, protective coordination, and transfer-sequence validation. Because the system uses lithium-based energy storage, installation must also comply with UL 9540 and UL 9540A fire safety requirements, including spacing, ventilation, and emergency shutdown provisions.

Decision Matrix and Scenario Comparison

In order to determine the most appropriate scenario for the site, four scenarios were developed and analyzed: business as usual (Case 0), installing a PV system only (Case 1), installing PV with a BESS (Case 2), and installing a BESS only (Case 3). Each case was evaluated in terms of resilience value, capital and operating expenditures, energy savings, payback period, and technical feasibility. The decision matrix summarizes the comparative performance of these options.

Criteria	Case 0: Baseline	Case 1: PV Only	Case 2: PV + BESS	Case 3: BESS Only
Resilience Benefit	None	Limited (daytime only)	Moderate (self-consumption, some coverage)	High (but redundant due to existing 125 kW generator)
CAPEX ($)	0	~$197k – $225k (≈$135k with ITC)	~$135k (PV after ITC + BESS fully covered by SGIP)	~$38k
OPEX ($/yr)	Current	~$2,143	~$3,543	~$340
Annual Utility Bill ($)	~$21k	~$10k	~$4k	~$21k (no reduction)
Annual Savings ($)	–	~$10k	~$16k	Minimal (non-financial)
Payback Period	–	~14 years	~10 years	No ROI
GHG Reduction	None	~38.6 $MTCO_2e$ avoided annually	Same as Case 1	None
Technical Feasibility	Already in place	Load-side interconnection not feasible; requires supply-side connection or service upgrade	Requires supply-side PV interconnection and dedicated storage integration	Technically feasible with dedicated emergency distribution connection

Table 3. Scenario Comparison

Conclusion

Based on the comparative analysis, **Case 2 (PV + BESS)** emerges as the preferred scenario for this site. While Case 1 (PV only) provides meaningful reductions in electricity costs and improves the environmental performance of the facility, the addition of a battery energy storage system significantly enhances the overall system value by allowing most of the solar generation to be consumed on-site rather than exported under the NEM 3 framework. Because export compensation under NEM 3 is significantly lower than retail electricity prices, storing excess solar production and using it later during higher-cost periods improves the overall financial performance of the project.

Case 2 therefore provides the strongest economic outcome, reducing the annual utility bill from approximately $20,755 to about $4,025 while increasing total annual savings to roughly $16,730. When accounting for system operating expenses, the project still generates a net annual benefit of approximately $13,277, resulting in a simple payback period of about 10 years. In addition to the economic benefits, the PV + BESS configuration improves operational flexibility and reduces reliance on the utility grid during peak periods.

From a technical standpoint, the existing electrical infrastructure can accommodate the proposed system through a supply-side interconnection or by installing dedicated service equipment for the distributed energy resources. This approach avoids exceeding NEC 705 bus loading limits at the existing 400 A service panel and provides a code-compliant pathway for integrating both the PV system and the battery energy storage system.

Overall, Case 2 provides the most balanced solution by combining strong financial performance, improved energy independence, and significant environmental benefits while maintaining a technically feasible interconnection strategy.

Summary of Strategy & Benefits

The selected strategy focuses on installing a rooftop PV system sized to offset 110% of the facility's annual energy consumption. This approach achieves the following benefits:

- **Resilience:** On-site solar generation combined with battery storage reduces reliance on the utility grid and improves operational continuity during peak demand periods.
- **Economic Savings**: Reduces annual utility costs from approximately $20,755 to about $4,025, representing a reduction of nearly 80% in electricity expenses.
- **Financial Feasibility**: Achieves a simple payback period of roughly 10 years while benefiting from federal ITC incentives and SGIP support for the battery system.
- **Environmental Impact**: Offsets approximately 38.6 metric tons of CO_2 emissions annually by replacing grid electricity with renewable solar generation.
- **Energy Optimization:** The battery stores daytime solar surplus and dispatches it during higher-value evening hours, maximizing the economic value of the PV system under NEM 3.
- **Technical Integration**: The PV and BESS systems can be integrated through a supply-side interconnection or upgraded service equipment to maintain compliance with NEC 705 requirements.
- **Operational Stability**: Provides long-term stability in operating expenses while increasing the facility's energy autonomy and reducing exposure to future electricity price increases.

Next Steps

To advance the project, the following steps are recommended:

1. **Detailed Design & Site Assessment:** Conduct a 30% design phase evaluation, including structural assessment of the roof, electrical interconnection details, and shading analysis
2. **Vendor Quotations:** Obtain updated vendor quotes for PV system equipment, installation, and interconnection to refine cost estimates beyond NLR benchmarks
3. **Permitting & Interconnection:** Coordinate with Southern California Edison (SCE) to complete the interconnection study and ensure compliance with NEM 3 tariff rules
4. **Finalize Incentive Applications:** Submit applications for the 30% ITC (direct pay) to secure federal funding and reduce upfront capital cost
5. **Procurement & Installation:** Issue RFPs for procurement and construction, selecting qualified contractors with experience in municipal PV installations
6. **Commissioning & Monitoring:** Upon installation, perform commissioning tests, integrate the system with monitoring platforms, and establish an operations and maintenance (O&M) plan to ensure reliable long-term performance

Appendix

Incentive Programs

This section outlines how the incentive programs function and provides relevant information about them. Specific application of these programs to presented scenarios is explored in previous sections.

Inflation Reduction Act

The Inflation Reduction Act of 2022 stands as a significant piece of legislation designed to strengthen the United States' commitment to fighting climate change by making considerable investments in renewable energy. A key feature of the Inflation Reduction Act is its financial incentives, namely the Investment Tax Credit (ITC) and the Production Tax Credit (PTC), which aim to accelerate the adoption of renewable energy technologies.

The ITC allows for a significant tax credit for investments in renewable energy technologies, including solar panels and wind turbines, directly reducing the upfront cost of these systems. This makes renewable projects more financially viable and attractive to investors and consumers alike. On the other hand, the PTC provides a per-kilowatt-hour tax relief for the production of energy from renewable sources, incentivizing the operation and expansion of renewable energy facilities.

Notably, Inflation Reduction Act programs have been subject to change in recent legislation. Presented here are active opportunities as of the time of the report.

Production Tax Credit

The Production Tax Credit (PTC) within the framework of the Inflation Reduction Act offers considerable financial incentives for renewable energy projects, primarily designed to decrease the federal income tax liability based on the electricity produced per kilowatt-hour.

The PTC directly reduces the federal income tax for taxable entities. Furthermore, for non-taxable entities such as local governments, educational institutions, or nonprofit organizations, the PTC allows these credits to be monetized, facilitating their involvement in renewable energy initiatives. This provision is applicable for projects that become operational between January 1, 2023, and December 31, 2032, providing a broad window for planning and implementation.

Projects located in designated low-income energy communities receive further incentives. The PTC is structured to be claimable annually for a decade from the start date of operations of the qualifying renewable system, providing long-term financial support. This current structure of the PTC is set to continue through the end of 2024. Starting from January 1, 2025, the credit system will transition to a technology-neutral format, broadening the scope to include a wider array of technologies and fostering a more inclusive approach to renewable energy incentives.

As of the date of this report, the program is still active but solar projects must have “begun construction” by July 4, 2026.

The City project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

Investment Tax Credit

The Investment Tax Credit (ITC) established under the Inflation Reduction Act offers a powerful incentive for deploying renewable energy technologies by providing a reduction in federal tax liability. This reduction is calculated as a percentage of the capital investment made in eligible energy systems. Taxpayers can apply the ITC to their federal income tax for the year the technology is installed, significantly decreasing their tax burden.

Starting January 1, 2023, special provisions enable tax-exempt entities such as local governments and nonprofits to receive direct payments equivalent to the value of the credit. This arrangement improves the liquidity and financial feasibility of renewable projects for these organizations. The scope of eligible technologies under the ITC is broad, encompassing solar panels, wind turbines, fuel cells, and other renewable energy systems.

As of 2025, the Investment Tax Credit (ITC) for solar projects is set at 30% of the eligible costs, encompassing both the equipment and installation expenses. This rate is scheduled to decrease to 26% in 2033 and further to 22% in 2034. Systems rated under 1 megawatt (MW) qualify for the full 30% without having to comply with additional requirements; larger systems will only receive the full amount if they meet specific labor requirements. These include paying prevailing wages to workers during construction and using apprentices to perform a portion of the total construction hours (15% after 2023). Bonus credits are available based on site location, e.g. low-income communities.

The ITC is set to continue delivering these benefits at its current rate until 2032, contingent upon meeting the specific project criteria laid out in the act. Looking ahead, post-2024, the ITC will transition to a technology-neutral system, which will be applicable to all zero-emissions technologies, reflecting a shift towards a more inclusive and adaptable approach to supporting renewable energy development.

HHZP project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

As of the date of this report, the program is still active but critical deadlines for project eligibility and complete operability are quickly approaching in 2026 and 2027, respectively.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) offers financial incentives to non-residential customers of utility Company to encourage the adoption of energy storage systems. These systems help businesses prepare for power outages that may occur due to weather, emergencies, or other unforeseen events. The SGIP funding is authorized through 2024, with incentives structured to decrease over time as funding milestones are reached or as more participants enter the program.

Non-residential customers have access to three types of SGIP rebates: General Market, Equity, and Equity Resilience. Furthermore, SGIP incentives are significantly higher for vulnerable or disadvantaged communities through the Equity and Equity Resilience categories.

Incentives are typically paid upfront for residential systems upon project completion and site verification, while nonresidential systems may receive half upfront with the balance paid based on the system's performance over time. Eligibility for SGIP incentives extends to residential, commercial, industrial, agricultural, and municipal customers of specific utilities including Pacific Gas & Electric, Southern California Edison, SoCalGas, San Diego Gas & Electric, and those managed by the Center for Sustainable Energy.

To be eligible for this rebate, a facility must satisfy two conditions: firstly, it must fall under the category of a government agency, educational institution, non-profit organization, or small business. Secondly, it must fulfill at least one of the following requirements: be located in a Disadvantaged Community (DAC), be situated in a census tract where the Median Household Income of the Statewide Median Income or be situated in California Indian Country.

On the other hand, the equity resilience rebate offers a rate, covering a percentage of the cost of an average energy storage system. To qualify for this rebate, a facility must meet certain requirements. Firstly, it must have experienced two or more utility Public Safety Power Shut-offs (PSPS), or it should be located in a Tier 2 or 3 High Fire Threat District (HFTD) and serve customers in DACs or Low Income Communities. Secondly, it must fulfill at least one of the following additional criteria:

- Be a police station, fire station, emergency response provider, emergency operations center, 911 call center, medical facility, private and public natural gas, electric, water, wastewater, or flood facility, jail or prison, utility-designated PSPS assistance center, cooling center, homeless shelter.
- Be a grocery store, supermarket, or corner store with less than $15 million in annual gross receipts.

- Be an Independent Living Center or a Food Bank.

Modeling Assumptions

The modeling conducted for this feasibility study was based on standard industry benchmarks, available site data, and conservative assumptions to ensure realistic projections. The following key assumptions were applied:

1. **Energy Consumption Baseline** – Historical hourly load data (8,760 points) from the facility was consolidated to represent a typical annual profile. This served as the reference for sizing PV and BESS systems.
2. **PV System Costs** – Capital expenditure (CAPEX) and operations and maintenance (OPEX) values were derived from the National Laboratory of the Rockies (NLR) 2024–2025 benchmarks for commercial rooftop systems. PV CAPEX was assumed at $1.75–$2.00/Wdc, with OPEX at ~$19/kW-year.
3. **BESS Costs** – Battery energy storage CAPEX was modeled using NLR 2025 benchmarks at ~$350/kWh. OPEX was assumed at ~$40/kW-year, covering maintenance, monitoring, and lifecycle management.
4. **ITC Incentives** – A 30% Investment Tax Credit (direct pay) was assumed, reducing upfront project cost. No additional low-income or disadvantaged community adders were included, since the site does not qualify.
5. **Performance Parameters** –
    - PV generation modeled with HelioScope using site tilt, azimuth, and shading factors.
    - Battery modeled with 90% round-trip efficiency and daily cycling where applicable.
    - Energy inflation rate of 3% annually applied to utility costs.
6. **Utility Tariff** – The analysis used the most recent Southern California Edison tariff, **TOU-GS-2 Option D**, as published in the file *ELECTRIC_SCHEDULES_TOU-GS-2_2025*. It was assumed under the current **NEM 3** framework. Exported PV energy was valued at ~25% of retail rate. Since tariff structures and prices are subject to future changes, the financial outcomes presented here should be viewed as indicative estimates rather than fixed projections.
7. **Infrastructure** – Electrical interconnection feasibility was preliminarily evaluated using customer-provided single-line diagrams. Minor breaker adjustment (600 A to 500 A) was assumed to comply with NEC 705.12 120% busbar rule for PV backfeed.
8. **Environmental Impact** – Greenhouse gas (GHG) reduction estimates were calculated using EPA eGRID emission factors for the CAMX subregion, applied to modeled PV generation.

Disclaimer: These figures are rough estimates intended for feasibility-level evaluation. If more precise values are required, additional detail must be developed through site-specific engineering, vendor quotations, and utility coordination during the advanced design phase.

Net Energy Metering

Net Energy Metering (NEM) in California is a billing arrangement that allows residential and commercial customers who generate their own electricity, primarily through solar photovoltaic (PV) systems, to receive credit for the surplus energy they contribute to the grid. This system is designed to incentivize the use of renewable energy sources by offsetting the cost of electricity consumption with the energy produced by these installations.

Under NEM, when a solar system generates more electricity than is consumed, the excess energy is sent back to the utility grid, and the customer earns credits. These credits can then be used to offset the cost of energy drawn from the grid when the solar system isn't producing enough to meet the customer's demand, like during nighttime or cloudy days. The rules, rates, and credits under NEM can vary over time, with different iterations such as NEM 1, 2, and the latest NEM 3, each having specific regulations and compensation structures for solar energy production and exchange.

The transition from NEM 2 to NEM 3 in California, which was effective on April 14, 2023, introduced significant changes in the net metering policies for utility customers with photovoltaic (PV) systems. These changes impact

several aspects, particularly the economics of energy arbitrage between PV system owners and the utility. Here's a summary of the key changes:

1) **Reduction in Export Rates:** Under NEM 3, there's a substantial reduction in the rates for excess electricity exported onto the grid by solar systems. This rate has been reduced by approximately 75%, thereby lowering the overall savings for home solar systems and increasing the payback period. This change is a shift from the traditional one-to-one offset of net metering policies, where the price of a kWh of electricity pushed onto the grid was equal to the price of a kWh pulled off the grid.
2) **Implementation of Electrification Rates:** Customers enrolling in NEM 3 are required to use electrification rates instead of regular Time-of-Use (TOU) rates. These electrification rates feature higher on-peak charges and lower off-peak charges, along with a fixed charge of $15 per month. The peak rate period remains from 4 pm to 9 pm.
3) **Export Compensation Based on Avoided Cost Calculator (ACC):** Export compensation under NEM 3 is determined by California's ACC, with specific export rates for every combination of Month, Hour, and Weekday or Weekend. The export value is lowest in the middle of the day when solar energy is abundant on the grid and highest during peak summer demand periods. Notably, the export rates are significantly lower than retail rates during the hours when PV systems are most productive (10 am – 3 pm). To maintain the financial viability of solar PV systems, customers in PG&E and SCE service territories receive an adder on top of the ACC rate, ranging between 2.2 and 9 cents depending on location and customer class.
4) **Shift to a Cost Avoidance System:** NEM 3 introduces a cost avoidance system for exported electricity. This system pays customers the lowest amount a company can pay under the Public Utility Regulatory Policies Act of 1978 (PURPA), which is significantly less than the typical retail rate. This results in customers receiving, on average, 75% less for the electricity they sell back to the grid, with rates varying by month and by hour.
5) **Grandfathering NEM 2 under NEM 3:** Under the recent NEM 3 policy in California, existing customers with a photovoltaic (PV) system installed under NEM 2 can retain the benefits and terms of their NEM 2 agreement, a process known as "grandfathering." However, these customers are restricted from replacing or adding capacity to their PV systems if they wish to maintain their NEM 2 status, as any significant modifications would require transitioning to the terms of NEM 3.

The Net Energy Metering (NEM) 3.0 policy introduces transformative changes, particularly enhancing the value of utilizing Battery Energy Storage Systems (BESS) for owners of solar power systems. A significant aspect of NEM 3.0 is the reduction in compensation rates for surplus electricity fed back into the grid by solar systems, now down to 75%. This adjustment shifts the financial dynamics, making it less lucrative to export excess solar energy to the grid. Instead, storing this surplus energy in a BESS and utilizing it when energy costs are higher becomes a more financially savvy approach.

The utility of BESS extends beyond merely optimizing the use of solar energy. It offers several additional advantages, such as providing backup power during utility blackouts, mitigating charges associated with demand peaks, and enabling energy arbitrage. Energy arbitrage under this system allows for the charging of BESS not only with excess solar energy but also with cheaper grid energy during low-cost periods. This stored energy can then be used in lieu of more expensive grid power at peak times, effectively reducing reliance on utility-supplied energy. Consequently, NEM 3.0 not only promotes more efficient use of solar energy but also broadens the scope of BESS applications, contributing to a more versatile and resilient energy management strategy.

AECOM



Microgrid Feasibility Study
City of Wildomar

Site:
City Hall
23873 Clinton Keith Road, Suite 101, Wildomar, CA

February 2026

Delivering a better world

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Executive Summary

This study appraises the viability and benefits of distributed energy resource implementation scenarios at the subject site. Four scenarios were analyzed, and key metrics are summarized below:

Case	Components	CAPEX ($)	Utility Savings ($/year)	Payback Period (years)	GHG Reduction ($MTCO_2e$/year)
1	PV	~$139k gross ~$97k with ITC	~$21,801/yr	~5 years	~24.5 metric tons CO_2e/yr
2	PV + BESS	~$153k (with ITC + SGIP)	~$31,910/yr	~5 years	~24.5 metric tons CO_2e/yr
3	BESS	~$84k	Minimal financial impact	No direct ROI	None
0	Business-as-usual	$0	—	—	None

Note: All values are approximate and subject to final design and incentive approval..

- **Case 1: Photovoltaic (PV) array –** Introduces on-site solar generation to offset approximately 105% of annual consumption, reducing energy and demand charges while maintaining compliance with NEC 705 interconnection limits.
- **Case 2: PV + battery energy storage system (BESS)** – Integrates PV with battery energy storage to maximize on-site self-consumption, reduce peak demand exposure, and enable load shifting under time-of-use pricing. Battery capacity can be moderately expanded to establish a resilience reserve for limited emergency support, enhancing system value without materially impacting payback.
- **Case 3: BESS only** – Provides emergency backup capability sized for critical loads; however, given the existing diesel generator capacity, incremental resilience benefit may be limited relative to cost.
- **Case 0: Business-as-usual** – Maintains full dependence on utility supply with continued exposure to demand charges and tariff volatility.

Based on the technical, economic, and operational evaluation, **Case 2 (PV + BESS)** represents the most comprehensive long-term strategy. It delivers the highest annual savings, maintains a strong payback profile, reduces exposure to peak rate volatility, and provides enhanced operational flexibility. The system also offsets approximately 24.5 metric tons of CO_2e annually through on-site renewable generation.

Recommended Next Steps

1. Advance to a 30% design phase with detailed site and structural assessments
2. Procure vendor-specific quotations to refine cost estimates beyond what is provided in this study
3. Initiate permitting and interconnection applications with Southern California Edison under the current Net Energy Metering tariff (NEM 3.0)
4. Secure federal incentives, specifically the 30% Investment Tax Credit (direct pay), to lower upfront costs
5. Prepare procurement and construction planning, targeting installation within the next budget cycle.

The goal is that with these data-driven microgrid feasibility assessment findings, the City of Wildomar can make an informed decision regarding an appropriate resilience-improving investment at the subject site.

Background

Purpose

In recent years, especially within the past decade, the impacts of extreme heat and wildfires have been profound through the Inland Empire. Power service disruptions have been increasing in frequency and severity throughout Riverside County, affecting the availability of essential services and community resources.

In 2023, the Western Riverside Council of Governments (WRCOG) received an award (Grant Agreement OPR23145) from the Adaptation Planning Grant Program of the California Governor's Office of Land Use & Climate Innovation Integrated Climate Adaptation and Resilience Program. This program provides funding to help fill local, regional, and tribal planning needs, provides communities the resources to identify climate resilience priorities, and supports the development of a pipeline of climate-resilient infrastructure projects across the state.

As part of this grant-funded project, the Energy Resilience Plan 2.0, WRCOG commissioned microgrid feasibility studies for its member agencies. These studies serve to provide valuation of a potential microgrid at a community-essential facility, as designated by the member agency.

The site selected for the City of Wildomar is the City Hall located at 23873 Clinton Keith Road, Suite 110, Wildomar, CA 92595.

This study presents key insights and findings from the evaluation of distributed energy resource (DER) scenarios, including photovoltaic (PV) array and battery energy storage system (BESS) components, at the subject site. It includes analysis of the site's historic energy demand profile and appraises potential PV array and BESS sizing and siting scenarios accordingly. Notably, the study includes assessment of the generation and storage requirements to support the site's critical loads to enable resilience for a specified number of hours during power service disruptions.

Furthermore, this study outlines the financial implications of self-generation, including estimated cost savings, return on investment (ROI), and potential financing options for the project.

It is important to note that this study serves as a preliminary technical and financial assessment. Its purpose is to provide the City of Wildomar with the information to make an informed decision on whether to proceed to next phases of microgrid implementation before committing to detailed engineering design and further investment.

Adaptation Planning Grant Program

As communities in California experience more frequent, prolonged, and severe impacts from climate change, communities and governments at all scales are developing strategies and implementing actions to build a climate-resilient future. However, many jurisdictions, especially under-resourced communities in California, lack the capacity, tools, guidance, and resources to effectively prepare for climate impacts.

The Adaptation Planning Grant Program addresses this capacity gap by providing funding to help fill planning needs, providing communities with the resources to identify climate resilience priorities, and supporting the development of climate resilience projects across the state. The Adaptation Planning Grant Program enables communities to climate risk and adaptation considerations into planning activities and prepare for climate readiness and resilience in the long term.

The Adaptation Planning Grant is part of the Integrated Climate Adaptation and Resiliency Program (ICARP) housed within the Governor's Office of Land Use and Climate Innovation. ICARP advances statewide climate adaptation and resilience by coordinating investments, partnerships, and climate science to ensure people, natural systems, and the built environment are protected, prepared, and thrive in the face of climate change.

Through direct and equity-focused investments and resources, ICARP helps build climate adapted and equitable communities in California, with a focus on solutions that address the impacts of climate change and reduce greenhouse gas emissions. ICARP works to advance these priorities across all levels of government by developing

actionable science and research; providing guidance, tools, and technical assistance; and administering climate resilience-focused grant programs.

Learn more: https://lci.ca.gov/climate/icarp/

Modeling Methodology

This section defines the criteria for sizing the PV array and BESS system components, detailing general parameters, technical requirements, and expected performance criteria.

PV Modeling

1. **Data Inputs**
    - **Solar Resource**: Hourly or sub-hourly irradiance data (e.g., typical meteorological year or on-site measurements)
    - **Site-Specific Factors**: Tilt angle, azimuth, shading analysis, and available roof/ground space
2. **Simulation Approach**
    - Use of HelioScope software to estimate hourly PV production
3. **Sizing Criteria**
    - **Capacity Target**: The sizing criteria are based on 105% the facility's current annual energy consumption. This approach aims to fully offset the facility's energy usage with the PV array while incorporating an additional 5% capacity to accommodate future demand growth. However, the final system capacity is constrained by the area designated as available by the client.
    - **Performance Ratio**: Evaluate Performance Ratio to ensure consistent system output
    - **Energy Production**: Hourly, daily, monthly, and annual PV generation forecasts
    - **Load Matching**: Amount of PV energy that directly offsets site load vs. excess exported to the grid

BESS Modeling

1. **Data Inputs**
    - **Load Profile**: Detailed electricity consumption and demand patterns
    - **PV Production Profile**: From the PV modeling results
    - **Energy Duration for Resilience**: Determine the critical loads that the BESS will support during islanding operations
2. **Operational Modes**
    - **Energy Shifting / Excess PV Storage**: Battery charges when PV output exceeds site demand, discharges when site demand is high.
    - **Resilience (Standalone BESS)**: Sized to support critical loads during outages
3. **Sizing Criteria**
    - **Capacity (kWh)**: Based on required autonomy (energy shifting, peak shaving, or resilience duration)
    - **Max Discharge/Charge Rate (kW)**: Aligned with site load peaks, PV generation surpluses, and emergency power needs
4. **Simulation Approach**
    - Hourly or sub-hourly dispatch modeling to maximize economic benefit (e.g., demand charge reductions or avoided peak rates)

- Incorporate battery round-trip efficiency, self-discharge, and operational constraints (e.g., partial charge strategies)

5. **Output**

   - **Discharge/Charge Profiles**: Hourly modeling of how the battery is utilized
   - **Cost Savings**: Reduction in energy and demand charges or avoided grid cost
   - **Backup Duration**: If sized for resilience, the total hours/days of critical load coverage

Assumptions

AECOM collected facility data through a request for information process. Energy consumption factors and facility characteristics were identified and integrated in analysis. AECOM used these combined datasets to confirm energy utility consumption baselines.

In performing the analysis, AECOM made the following assumptions:

- This report refers to the site, located at 23873 Clinton Keith Road, Suite 110, Wildomar, CA 92595.
- The monthly and annual electricity consumption is determined using load profile data in the client-provided 5 files that contains 35040 load profile data points, which are then consolidated into an 8760 load profile dataset.
- AECOM utilized the Levelized Cost of Energy (LCOE) for the installed cost per watt of PV installations and BESS, as sourced from the National Laboratory of the Rockies (NLR). This data was used to estimate the hypothetical cost of installing the PV array and BESS at the site, as detailed in this report. For an accurate cost estimation, it is necessary to obtain vendor quotes, which are subject to change due to market-dependent time windows. These quotations are typically conducted during the 60% design phase, at which point there is an understanding of the specific equipment ratings and brands to be used.
- This report evaluates the site's existing electrical infrastructure using customer-provided data on the main breaker and bus capacity, as documented in the client-provided file "City Hall Single line Electrical Diagram." AECOM has assessed whether the existing electrical system can support the proposed PV array and BESS installation. However, as this is a feasibility study, an on-site assessment is required for a definitive determination. A site visit should be conducted during the advanced design phase, typically at the 30% design stage, to confirm site-specific conditions.
- AECOM has estimated the potential PV generation capacity based on site availability. A more detailed assessment will be required in later project phases, typically at the 30% design stage, to confirm that the site has the necessary infrastructure to support PV array installation. This evaluation includes civil and structural considerations, load-bearing capacity, especially for rooftop systems, and other critical conditions required for successful implementation.
- The facility is currently served under SCE's TOU-GS-2 tariff; however, this analysis was performed using the TOU-GS-2-E rate structure, which more accurately reflects the site's demand characteristics and provides a more appropriate framework for evaluating PV and BESS performance under time-of-use pricing. If the microgrid project proceeds, it is recommended that the facility transition to the TOU-GS-2-E tariff to align with the operational strategy and financial assumptions modeled in this study.
- For the purpose of this feasibility analysis, the site's five utility meters were evaluated as a single aggregated point of interconnection, treating the facility as one unified electrical load for modeling and tariff simulation purposes. This approach allows for consolidated demand and energy analysis consistent with a behind-the-meter microgrid configuration. The meter numbers included in this assessment are: 259000-014050, 256000-115378, 256000-107353, 256000-200186, and 256000-107350.
- This report uses a regionalized estimate of general production (kWh) to calculate the amount of greenhouse gas emissions avoided through PV generation. The calculation is based on the U.S. EPA Emissions & Generation Resource Integrated Database (eGRID).
- This report clarifies that other charges such as connection fees, required service charges, and taxes remain unchanged. The analysis focuses solely on the bill components directly affected by the installation of PV and BESS under the NEM 3 framework.

AECOM utilized the following tools in conducting the analysis:

- AECOM Internal Tools: Proprietary tools developed by AECOM for analyzing energy patterns and evaluating system performance in simulated environments. These tools are designed to assess energy costs for applications such as peak shaving, energy trading, etc. in DER implementations.
- HelioScope: Web-based software tool used for the design and performance analysis of photovoltaic systems. It combines system layout design with energy simulation, allowing users to model rooftop, ground-mounted, and canopy PV installations. The software factors in module placement, tilt, azimuth, shading, and local weather data to provide accurate estimates of system capacity and expected energy generation.

Site Information

This study is conducted for City Hall, located at 23873 Clinton Keith Road, Suite 110, Wildomar, CA 92595. The fire station currently consumes about **119,266 kilowatt-hours (kWh) per year**.

In terms of electrical infrastructure, the site is served by a main switchboard designated “MSK” with a 2000-ampere (A) bus rating, 208Y/120 volt (V), three-phase, four-wire configuration, and an available interrupting capacity of 65 kilo-ampere interrupting capacity (kAIC) (NEMA 1 enclosure), fed from the serving utility (SCE).

The switchboard distributes power through multiple feeder breakers (predominantly 100 A and 200 A, with a 1600 A section shown on the lineup) to numerous panelboards (HPK, PK101 through PK211) and a dedicated elevator load. The load summary indicates a total connected load of 311,332 volt-ampere (VA) (approximately 311 kilovolt-ampere [kVA]) at 208Y/120 V, 3-phase, 4-wire.

The drawings indicate a copper grounding and bonding approach including a #3/0 AWG copper UFER grounding conductor and #3/0 AWG copper bonding to the cold water service and building steel, with series-rated breaker coordination requirements noted for downstream devices. Transformer, automatic transfer switch (ATS), and generator ratings are not shown on the provided single-line sheet, so those values cannot be stated from this diagram.

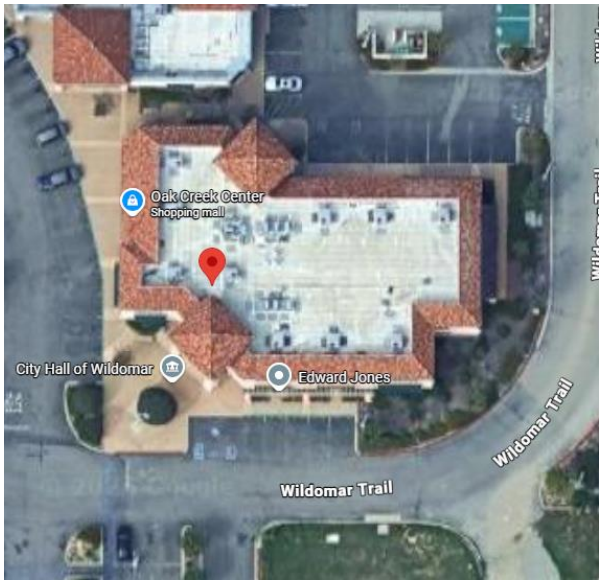


Figure 1. Site Location

Incentive Programs

AECOM has identified three key incentive programs that could benefit the subject site, focusing on renewable energy production and advanced energy storage systems.

The Investment Tax Credit (ITC) and Production Tax Credit (PTC) are federal incentives that reduce the cost of renewable energy projects. ITC offers a tax credit based on a percentage of upfront investment costs, while PTC provides a per-kilowatt-hour credit for electricity generated over time.

Production Tax Credit

Under this initiative, the project is eligible for a tax credit ranging from 0.3 cents to 1.5 cents per installed kWh. The specific value of the credit is determined by several factors, including the project's adherence to certain requirements such as complying with labor standards and using domestic materials.

The PTC program pays for each kilowatt-hour produced over a 10-year period, with government entities receiving the benefit as direct pay instead of a tax credit. For this project, with an estimated 125,680 kWh per year, the best case at 1.5 ¢/kWh would yield about $1,885 annually, totaling around $18,852 over 10 years.

Investment Tax Credit

The City can take advantage of either the ITC or the PTC, but both cannot be utilized simultaneously. Since construction has not yet commenced, selecting the ITC is the most advantageous option. Under this scenario, the project is limited to the base 30 percent credit because it does not meet any conditions for additional bonus allocations.

The ITC provides an extra 10 percent credit for projects located in federally designated low-income communities. However, according to the 2016–2020 census tract classification shown in Figure 3, the project site is located outside the eligible low-income area. As a result, the project does not qualify for the additional 10 percent bonus and remains capped at the standard 30 percent ITC.

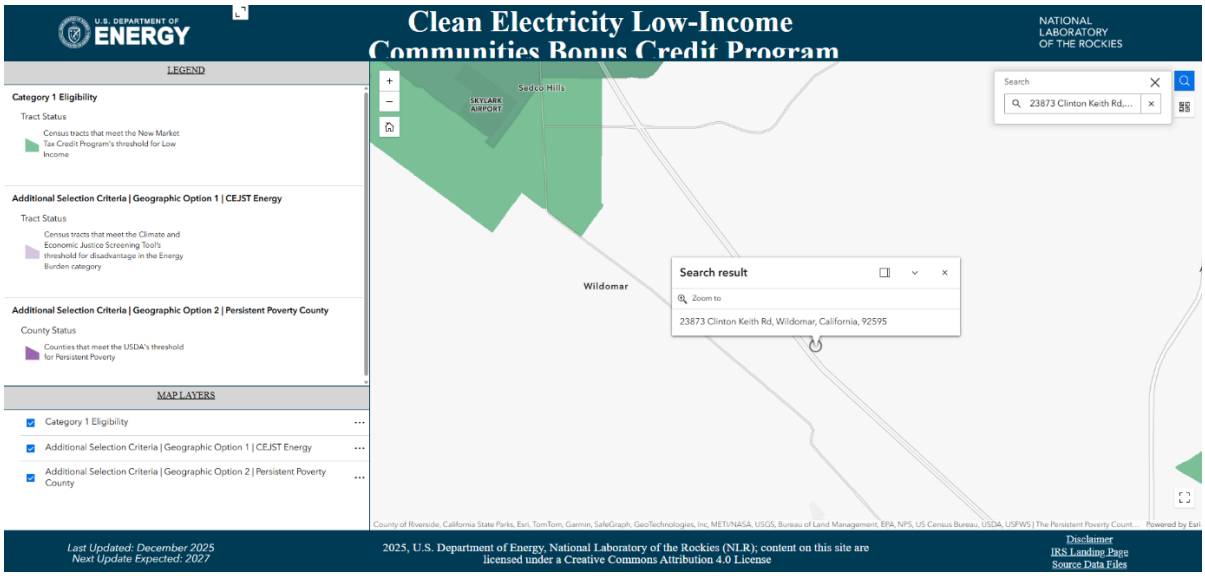


Figure 2. Clean Electricity Low-Income Communities Bonus Credit Program Map

NLR estimates capital expenditure (CAPEX) for commercial PV at $1.75–2.00 /W direct current (DC). For this study, a 69.6 kilotwatt (kW) DC PV system is projected. Based on these CAPEX values, total installation cost ranges from $121,800 to 139,200. With the standard 30 percent ITC, the direct-pay benefit for the City would fall between $36,540 and $41,760.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) is California's primary incentive designed to reduce the upfront cost of energy storage systems. The program has three levels:

- **General Market:** For projects located outside Disadvantaged Communities (DAC). Typical incentive: $0.10 /Wh.
- **Equity (DAC):** For projects located within a DAC. Incentive: $0.85/Wh.
- **Equity Resilience:** For critical facilities within a DAC and in PSPS or high fire-risk zones. Incentive: $1.00/Wh.

In Case 1, the project site is outside a DAC, so it only qualifies for the General Market level. Using an NLR-based cost of $450/kWh, a 160-kWh battery would cost approximately $72,000. With the General Market incentive of $0.10/Wh, the project would receive about $16,000, resulting in a net battery cost of roughly $56,000.

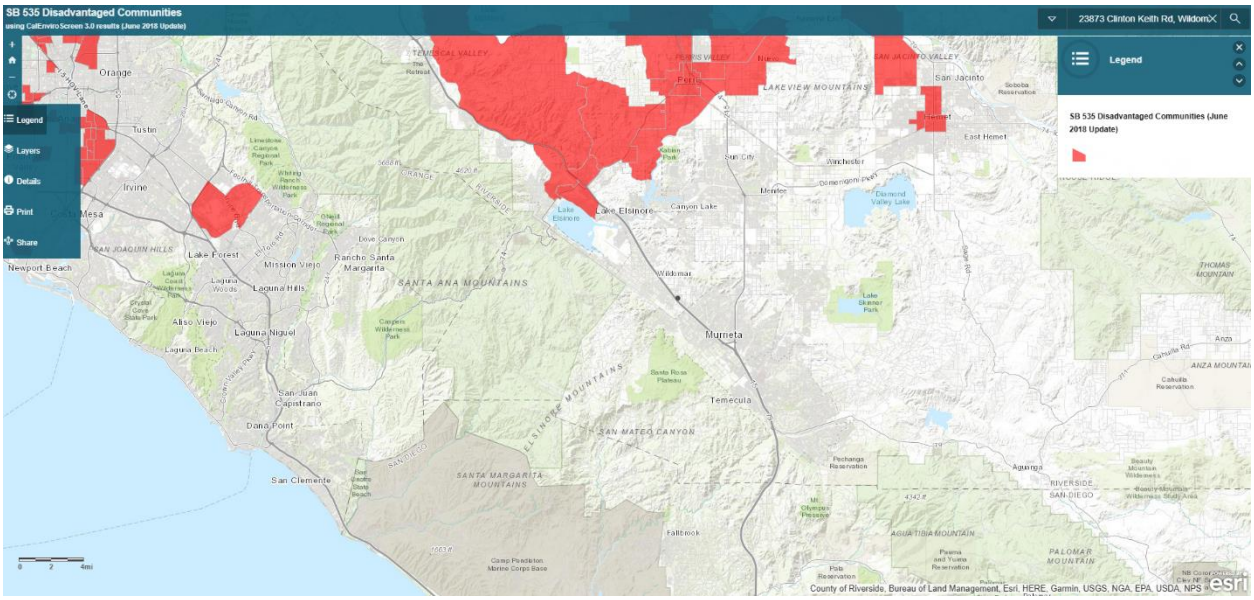


Figure 3. SB 535 Disadvantaged Communities Map

Scenarios & Analysis

Case 0: Current Situation (Baseline)

Tariff & Contract Type

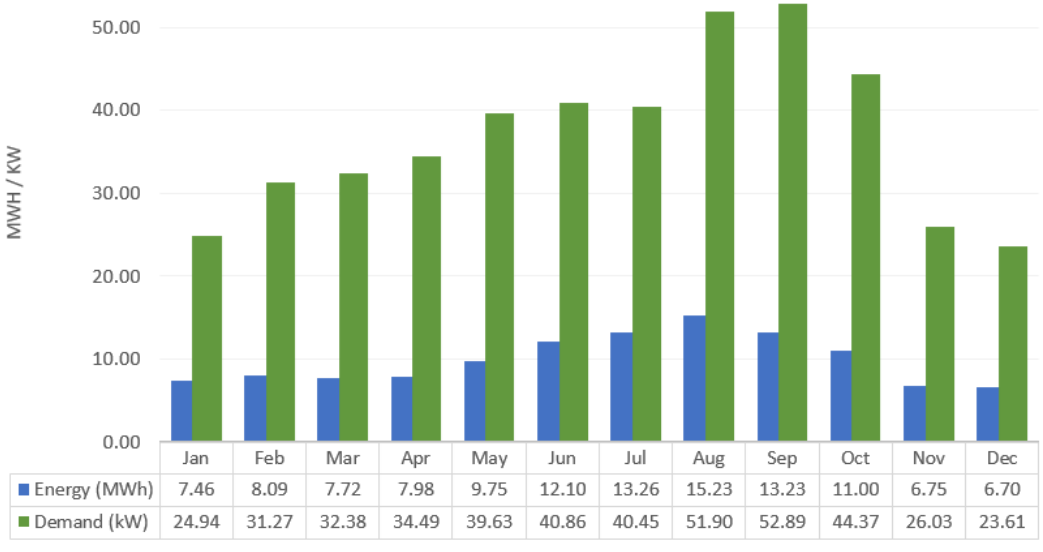
The site is currently served by Southern California Edison under the TOU-GS-2-E tariff, which is designed for small to medium commercial customers. This rate structure separates costs into energy charges (based on kilowatt-hours consumed) and demand charges (based on the highest kilowatt demand registered during the billing cycle). In addition, prices vary by time-of-use periods—on-peak, mid-peak, and off-peak—so the timing of energy use significantly affects overall costs.

Being on this tariff means the site's operating expenses are directly tied not only to how much energy is consumed but also to when it is consumed and how high the peak demand reaches.

The tariff cost presents the costs as totals (delivery + bundle). The prices were used as the basis for this study. While they may fluctuate slightly month to month depending on market conditions, these variations are generally minor.

Monthly & Annual Energy Consumption and Demand

The facility currently consumes 119,266 kWh annually, with August being the highest month at about 15,230 kWh and December the lowest at about 6,700 kWh. In terms of demand, September records the peak at around 52.89 kW, while December is the lowest at about 23.61 kW. The following graph presents this historical data for the 2024–2025 period.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Energy (MWh)	7.46	8.09	7.72	7.98	9.75	12.10	13.26	15.23	13.23	11.00	6.75	6.70
Demand (kW)	24.94	31.27	32.38	34.49	39.63	40.86	40.45	51.90	52.89	44.37	26.03	23.61

Figure 4. Historic Site Energy Profile

Monthly & Annual Energy Costs

The site currently spends about $38,440 per year in energy and demand cost, with approximately $30,235 in energy costs and $8,206 in demand charges, based on tariff TOU-GS-2-E simulation. For this analysis, we are focusing only on energy and demand costs, as these are the components directly impacted by the installation of a PV system.

Case 1: PV Only

Installed Capacity & Location

The PV system for the site was sized to offset approximately 105% of current consumption, with the goal of fully offsetting present usage while reserving about 5% additional capacity for future growth. The placement areas for the PV installation were identified according to customer requirements. The system capacity is estimated at 69.6 kW DC, with an expected annual production of about 125,680 kWh.

Figure 6 presented the modeled energy production throughout the year, and Figure 7 identifies the designated PV installation areas on the site.

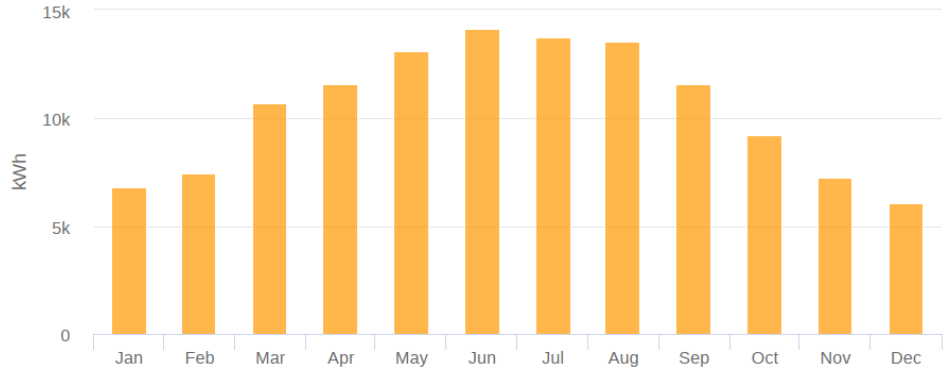


Figure 5. Modeled PV Production



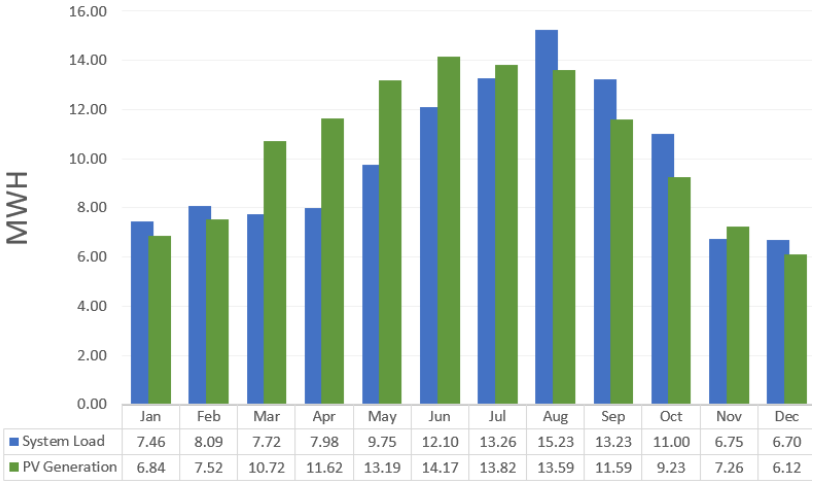
Figure 6. Modeled PV Installation Areas

Modeled PV Production

The modeled PV system is projected to generate an average of 10,473 kWh per month, with an estimated annual production of 125,680 kWh.

This scenario doesn't include a BESS, so the excess energy produced need be exported to the utility, which requires entering a Net Energy Metering (NEM) contract with the utility service provider. Under the currently available NEM tariff, NEM 3.0, exported electricity is credited at dynamic rates that vary by month, hour of day, and weekday, ranging from as low as $0.01/kWh during midday hours to over $1.00/kWh during peak evening hours in high-demand months like August and September. This study has calculated projected benefits from this arrangement.

Figure 8 compares historic monthly energy consumption and modeled PV generation. Not all solar energy will be consumed on-site, as excess daytime production may exceed demand and be exported to the grid, while nighttime demand cannot be covered since there is no generation after sunset and no battery to store the excess in this scenario.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
System Load	7.46	8.09	7.72	7.98	9.75	12.10	13.26	15.23	13.23	11.00	6.75	6.70
PV Generation	6.84	7.52	10.72	11.62	13.19	14.17	13.82	13.59	11.59	9.23	7.26	6.12

Figure 7. Modeled PV Output vs. Site Demand

Capital Expenditures

Based on NLR benchmark CAPEX values for commercial rooftop solar, the estimated cost to install a 69.6 kW DC PV system in Riverside County, California falls in the range of $1.75 to $2.00 per watt DC. This translates to a total investment of **approximately $121,730 - $139,120 for the complete system**.

These figures include typical equipment, installation, and soft costs, reflecting average market conditions for commercial-scale projects. Actual costs may vary slightly depending on site-specific conditions such as roof structure, permitting, interconnection requirements, and labor. However, the NLR benchmarks provide a reliable basis for estimating the capital cost of a system of this size and type in the region.

Operating Expenses

According to NLR's 2024 benchmark data, the annual operations and maintenance (OPEX) cost for commercial rooftop PV systems is about $19 per kW-DC. For a 69.5 kW DC system, this translates to an **estimated yearly OPEX** of roughly **$1,322** covering routine maintenance, monitoring, and related operational expenses.

Economic Metrics

The analysis shows that installing a PV system at the site under NEM3 provides measurable financial benefits by offsetting both energy and demand charges. Without solar, the facility currently spends about $38,440 annually on utility costs. With the PV system in operation, the energy cost is reduced to approximately $14,228 per year, while the demand cost drops to about $5,597 per year. In addition, the system generates excess electricity during the day that cannot be fully consumed on-site. Under NEM3 rules, this exported energy represents an additional benefit of roughly $3,185 annually. Taken together, these reductions and export credits bring the facility's total utility bill down to **$16,639 per year**, achieving an **overall savings of about 57%** compared to current expenses

Payback Period and Return on Investment

The financial analysis shows that without PV, the facility spends approximately $38,440 per year on utility costs. With a 69.6 kW DC PV system installed, the annual cost is reduced to about $16,639, resulting in yearly savings of roughly $21,801. When accounting for modest energy price inflation over time, these annual savings are expected to increase

The total capital cost of the system is estimated at $139,120, but with the 30 percent ITC direct pay, the net investment is reduced to approximately $97,384. In addition, the system carries an annual OPEX of $1,322, which slightly offsets the yearly savings. Taking these factors into account, the project generates a net benefit of about $21,801 minus 1,322 per year after OPEX. This results in a simple payback period of approximately 5 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross Savings ($)	Net Savings after OPEX ($)	Cumulative Cash Flow ($)
1	21,801	19,497	-77,887
2	22,455	20,082	-57,806
3	23,128	20,684	-37,122
4	23,822	21,304	-15,817
5	24,537	21,944	6,126
6	25,273	22,602	28,728
7	26,031	23,280	52,008
8	26,812	23,978	75,986
9	27,616	24,698	100,684
10	28,445	25,439	126,123
15	32,975	29,490	265,232
20	38,228	34,187	426,497

Table 1. Return on Investment w/ 3% Inflation: Case 1

Technical Feasibility

The facility electrical distribution is served by main switchboard MSK rated 208Y/120 V, 3-phase, 4-wire, with a 2000 A main bus and 2000 A main overcurrent device.

A 69.6 kW PV system interconnected at 208 V, 3-phase produces an AC output current of 193 A (69,600 W divided by 1.732 times 208 V). Per NEC 705 ampacity and overcurrent sizing, the required PV backfeed breaker is 242 A minimum (193 A times 125 percent), which rounds to a standard 250 A, 3-pole breaker.

Applying NEC 705.12 busbar loading, the maximum allowable PV backfeed on a 2000 A bus with a 2000 A main is 400 A (1.20 times 2000 A minus 2000 A). The required PV breaker rating is 250 A, which is compliant with a 150 A margin relative to the NEC 705 backfeed limit.

Interconnect the PV system using a 250 A, 3-pole backfed breaker on MSK located to satisfy NEC 705 busbar loading placement requirements, provide the required backfeed retention means, and apply all NEC 705 labeling and directory updates at MSK and the PV point of connection. No switchboard bus or main breaker upgrades are required for NEC 705 compliance at the stated PV size.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 125,680 kWh per year. Using the U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:

- Carbon dioxide (CO_2): 53,841.3 pounds (lbs) (24.42 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 54,042.4 lbs (24.51 metric tons) avoided annually
- Nitrogen oxides (NO_x): 41.7 lbs (18.93 kg) avoided annually
- Sulfur dioxide (SO_2): 2.5 lbs (1.14 kg) avoided annually

Case 2: PV + BESS

System Components

This scenario assumes the same PV array described in Case 1 and a BESS sized for surplus PV production. The day with the highest energy surplus in our simulation occurred on May 26, during which the PV system produced 478.97 kWh, the site consumed 199.41 kWh, and the resulting surplus was 279.56 kWh. For size the BESS, we ran several iterations based on the available surplus energy and applied an algorithm that simulates the charge and discharge cycles of one year. This techno-financial analysis indicates that the optimal BESS capacity is approximately 600 kWh.

This simulation factor ensures that even under variations in production or demand, all possible excess solar energy generated during the day can be stored. The stored energy is then available for use at night or during periods when PV production does not fully cover the site's demand.

By doing so, most of the units of solar energy produced on-site are consumed daily by the facility, preventing as little as possible any export to the grid.

Modeled Energy Flows

By installing a 160 kWh battery, we ensure that all the energy generated on-site is consumed by the facility itself. The charge and discharge profile of the battery is designed so that any PV surplus during the day is immediately stored in the battery rather than exported to the grid. Later, if the site demand exceeds the PV generation while there is still energy stored in the battery, the deficit is supplied from the battery.

This operational strategy minimizes or even eliminates consumption from the utility, since the PV and battery combination is prioritized to cover the load at all times. On an annual basis, the system is expected to produce slightly more energy than the site requires, leaving a surplus of around 10%, but this excess is negligible in terms of the overall utility bill.

Capital Expenditures

According to NLR benchmark data, the capital expenditure (CAPEX) for a commercial-scale 69.6 kW DC rooftop PV system in Riverside, California is estimated at $97,384 under ITC incentive, based on installation costs of $1.75–2.00 per watt DC.

For storage, NLR's 2025 cost projections indicate a CAPEX of $450 per kWh for the high-cost scenario. Applying this benchmark to a commercial-scale 160 kWh battery system represents an investment of roughly $72,000 and under the SGIP program this amount can covered 29% of the BESS system

Together, the **combined CAPEX for the PV and BESS systems** under incentives is estimated at **$153,384** representing the expected upfront investment for a commercial solar-plus-storage project of this size.

Operating Expenses

According to NLR benchmark data, the annual operations and maintenance (OPEX) cost for a commercial-scale 69.1 kW DC rooftop PV system is estimated at $1,322.

NLR data indicates an operating cost of approximately $4 per kW-year. For a commercial-scale 160 kWh battery system, this results in an annual OPEX of about **$640**.

Together, the combined OPEX for the PV and BESS systems is approximately **$1,962** per year, covering routine maintenance, monitoring, and system management.

Economic Metrics

The analysis shows that installing a commercial-scale PV system paired with a **160 kWh** battery under NEM 3 provides strong financial advantages by allowing a substantial portion of the solar energy produced by the PV system to be consumed on-site.

In several cases, PV production exceeds the facility's demand, and the surplus can be stored in the BESS for later use. However, without a battery system, the facility cannot absorb all of this excess energy, since any unused generation must be consumed the moment it is produced. This unused energy would otherwise need to be exported

to the utility grid, where under current NEM rules it would be compensated at only about 25 percent of the retail electricity rate. Given that time-of-use pricing makes stored energy far more valuable during high-cost periods, it becomes financially preferable to store surplus solar rather than sell it.

Without a BESS, exporting this excess would generate $3,185, but the facility would still face an annual utility cost of $16,639. By contrast, installing the BESS reduces grid reliance and allows the facility to consume nearly all of its solar production during higher-priced periods, resulting in a significantly lower annual utility bill of $6,530.

To remain conservative, this analysis assumes that 10% of annual energy costs remain due to efficiency losses, imperfect alignment of PV output and site load, and seasonal variability.

It is important to note that other charges—such as connection fees, requisite charges, and taxes—remain unaffected. This analysis focuses only on those bill components directly impacted by the installation of PV and BESS under the NEM 3 framework.

Payback Period and Return on Investment

The financial analysis shows that without PV + BESS, the facility spends approximately $38,440 per year on utility costs. With a 69.6 kW DC PV system and 160 kWh BESS system installed, the annual cost is reduced to about $6,530 resulting in yearly savings of roughly $31,910. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system under ITC and SGIP incentives is estimated at $153,384. In addition, the system carries an annual OPEX of $1,962. Taking these factors into account, the combined system generates a net benefit of about 29,948 per year after OPEX. This results in a simple payback period of approximately 5 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross-Savings ($)	Net-Savings after OPEX ($)	Cumulative Cash Flow ($)
1	31,910	29,948	-123,436
2	32,867	30,846	-92,590
3	33,853	31,772	-60,818
4	34,869	32,725	-28,093
5	35,915	33,707	5,614
6	36,992	34,718	40,332
7	38,102	35,759	76,091
8	39,245	36,832	112,924
9	40,423	37,937	150,861
10	41,635	39,075	189,936
15	48,267	45,299	403,616
20	55,954	52,514	651,330

Table 2. Return on Investment w/ 3% Inflation: Case 2

Technical Feasibility

The existing electrical system is centered on Main Switchboard “MSK” rated 2000 A at 208Y/120 V, 3-phase, 4-wire, feeding multiple downstream panelboards (HPK, PK101 through PK211) and an elevator load, with a documented total connected load of 311,332 VA (865 A at 208Y/120 V).

The proposed PV addition is 55 kW AC, which corresponds to approximately 153 A of 208 V, 3-phase output current. A dedicated PV interconnection OCPD must therefore be sized at not less than 125 percent of this output (minimum 192 A), which drives a 200 A PV breaker and conductors sized accordingly for continuous operation.

A 160 kWh BESS must be interconnected through a listed bidirectional inverter and a dedicated breaker on MSK. The BESS breaker and conductors must be sized from the inverter’s maximum continuous AC output current at 208 V, 3-phase, using the same continuous-duty sizing basis, and coordinated with the available spaces and breaker positions shown on the MSK lineup.

If both PV and BESS are interconnected on the load side of MSK, NEC 705.12 bus loading must be verified at the exact connection point. With a 2000 A bus and a 2000 A main, the 120 percent allowance is 2400 A, leaving 400 A total available for the sum of backfed DER breakers at a compliant location; the 200 A PV breaker consumes 200 A of that allowance, leaving 200 A remaining for the BESS breaker before MSK exceeds the 120 percent limit.

If the required BESS breaker exceeds the remaining 200 A bus allowance, or if the physical breaker placement cannot meet the bus-end requirements for a compliant load-side connection, the practical electrical update is to implement a supply-side (line-side) interconnection ahead of the MSK main with utility-approved metering and a dedicated fused disconnect for PV and for BESS, thereby removing the DER contribution from the MSK 120 percent bus constraint.

In all cases, a protection and coordination review is required to confirm interrupting ratings and selective coordination for the added DER breakers and disconnects, and to confirm grounding and bonding continuity at the 208Y/120 V service. The PV and BESS must include utility-required visible, lockable AC disconnecting means and compliant labeling at MSK and at each DER disconnect.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 125,680 kWh per year. Using the U.S. EPA’s Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:

- Carbon dioxide (CO_2): 53,841.3 lbs (24.42 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 54,042.4 lbs (24.51 metric tons) avoided annually
- Nitrogen oxides (NO_x): 41.7 lbs (18.93 kg) avoided annually
- Sulfur dioxide (SO_2): 2.5 lbs (1.14 kg) avoided annually

CASE 3: BESS Only

Critical Load Identification

The facility is classified as a general Facility Center operating at 208Y/120V, three-phase, four-wire service with a total connected load of approximately 280 kW. Based on NEC 700, NEC 701, NFPA 110, and NFPA 72 requirements for this occupancy type, only life-safety systems are mandated to receive emergency power, including egress illumination and fire alarm systems.

However, no dedicated emergency branch panels, fire pump loads, or clearly segregated life-safety feeders are identified in the one-line diagram

Furthermore, the observed maximum facility demand is 50 kW. Since no distinct critical loads are explicitly identified, the emergency load analysis is conservatively based on 60 kW to provide margin above the measured peak demand.

The total critical load used for this analysis is 60 kW.

Required Backup Duration

For the site, maintaining continuous operation of alarm systems, emergency communications, lighting, and fuel dispensing is essential to guarantee mission readiness. According to NFPA 110 (Section 4.2 and 7.12.1), emergency power supply systems (EPSS) must provide a minimum of 2 hours of operation at full rated load. However, for critical public safety facilities, most Authorities Having Jurisdiction (AHJs) and best practice guidelines require at least 4 hours of backup capacity to ensure firefighters can respond to emergencies during extended outages.

Battery Capacity & Infrastructure

The battery system must support 60.0 kW of emergency demand. Using a 4-hour duration, the required stored energy capacity is 240 kWh.

The BESS must therefore be rated at 60.0 kW minimum continuous discharge capability and 240 kWh usable energy. The main switchboard MSK is rated 2000A at 208Y/120V as shown on the one-line diagram

Integration would require either a dedicated breaker within available switchboard capacity or installation of a separate emergency distribution panel supplied through an automatic transfer switch.

Interconnection must verify bus capacity and confirm compliance with NEC 705.12 load-side interconnection limits if backfeeding is proposed.

Capital Expenditures

Using cost benchmarks published by the National Laboratory of the Rockies (NLR), the estimated CAPEX for a 60 kWh / 20 kW battery energy storage system is approximately **$84,000**. This figure includes the battery cabinets, inverter/PCS, microgrid controller with ATS, installation, protections, and engineering.

Operating Expenses

The expected **OPEX** is about **$960 per year**, also based on NLR reference values. This covers preventive maintenance, monitoring software, and NFPA 110 testing requirements. Battery replacement is typically required after 10–12 years of service.

Return on Investment & Qualitative Benefits

While a conventional financial return (ROI) cannot be directly applied to this case, the value of a BESS for a Facility Center is framed in terms of resilience, reliability, and compliance. Such systems are designed to ensure uninterrupted operation of life-safety and mission-critical equipment during extended utility outages. The benefits include maintaining operational continuity, reducing safety risks, and ensuring compliance with NFPA 110, NFPA 70, and NFPA 72.

However, for this particular facility, the justification for a BESS must be evaluated against the existing backup assets. If the generator capacity already exceeds the emergency requirement, the incremental resilience provided by the

BESS may be limited relative to cost. In these situations, the decision typically shifts from technical necessity to redundancy preferences, policy considerations, or long-term reliability planning.

Technical Considerations

The main switchboard is rated 2000A at 208Y/120V three-phase.

Any BESS interconnection must verify bus loading and comply with NEC 705.12 load-side interconnection limitations if backfeed configuration is used.

Breaker sizing must reflect full-load current of approximately 167A for a 60 kW system at 208V three-phase. Short-circuit contribution of the inverter must be evaluated against the switchboard interrupting rating.

A full short-circuit study, coordination review, transfer-sequence validation, and UL 9540A fire safety compliance assessment are required prior to final design implementation.

Decision Matrix and Scenario Comparison

In order to determine the most appropriate scenario for the site, four scenarios were developed and analyzed: business as usual (Case 0), installing a PV system only (Case 1), installing PV with a BESS (Case 2), and installing a BESS only (Case 3). Each case was evaluated in terms of resilience value, capital and operating expenditures, energy savings, payback period, and technical feasibility. The decision matrix summarizes the comparative performance of these options.

Criteria	Case 0: Baseline	Case 1: PV Only	Case 2: PV + BESS	Case 3: BESS Only
Resilience Benefit	None	Limited (daytime only)	Moderate (self-consumption, some coverage)	High (4-hour emergency load support at 60 kW)
CAPEX ($)	0	~$121,730–$139,120 (gross) ~$97,384 (with ITC)	~$153,384 (PV + BESS with ITC + SGIP)	~$84k
OPEX ($/yr)	0	~$1,322	~$1,962	~$960
Annual Utility Bill ($)	~$38,440	~$16,639	~$6,530	~$38,440 (no reduction)
Annual Savings ($)	–	~$21,801	~$31,9108	~$38,440 (no reduction)
Payback Period	–	~5 years	~5 years	No ROI
GHG Reduction	None	~24.5 $MTCO_2e$ avoided annually	Same as Case 1	None
Technical Feasibility	Already in place	NEC 705 compliant on 2000 A bus (250 A breaker; 150 A margin remaining)	Bus allowance limited to 400 A total DER; may require line-side interconnection depending on BESS breaker size	Requires ATS integration; must verify breaker capacity and short-circuit contribution

Table 3. Scenario Comparison

Conclusion

Based on the comparative analysis, **Case 2 (PV + BESS)** emerges as the optimal scenario for the facility. While Case 1 (PV-only) delivers strong financial returns with lower capital investment, Case 2 provides a superior balance between economic performance, operational control, and resilience enhancement.

By integrating a 69.6 kW DC PV system with a 160 kWh battery energy storage system, the facility reduces its annual utility bill from approximately $38,440 to about $6,530, achieving annual savings of roughly $31,910. Although the combined capital investment is higher than PV-only, the system maintains an attractive simple payback period of approximately 5 years while significantly reducing exposure to peak demand charges and time-of-use rate volatility under the TOU-GS-2-E tariff.

Importantly, the BESS capacity can be modestly increased beyond the base economic optimization size to incorporate a defined resilience reserve. By allocating a portion of stored energy exclusively for emergency operation, the system can provide limited backup support for critical loads without substantially altering the financial performance of the project. This enhancement transforms Case 2 from a purely economic load-shifting strategy into a dual-purpose system that delivers both financial return and resilience capability.

Unlike Case 3 (BESS-only), which provides resilience without measurable financial return, the optimized Case 2 configuration delivers both cost savings and operational continuity. For this reason, Case 2 represents the most strategically balanced and technically sound solution for long-term facility performance.

Summary of Strategy & Benefits

The selected strategy consists of installing a rooftop PV system sized to approximately 105% of annual consumption, paired with a BESS optimized for daily solar capture and peak demand mitigation, with the flexibility to incorporate additional battery capacity to establish a resilience reserve. This approach achieves the following benefits:

- **Resilience:** Provides load-shifting capability under normal operation and the ability to maintain limited critical load support during outages through reserved battery capacity.
- **Economic Savings:** Reduces annual utility costs by approximately 83%, from about $38,440 to $6,530.
- **Financial Feasibility:** Maintains an estimated simple payback of approximately 5 years, even with modest battery capacity expansion.
- **Environmental Impact:** Offsets approximately 24.5 metric tons of CO_2e annually by maximizing on-site renewable energy utilization.
- **Technical Compliance:** Achievable within NEC 705 constraints with appropriate verification of busbar loading or implementation of a line-side interconnection if required.
- **Operational Optimization:** Maximizes on-site solar self-consumption, reduces demand peaks, mitigates tariff volatility, and enhances long-term infrastructure resilience without introducing unnecessary system redundancy.

Next Steps

To advance the project, the following steps are recommended:

1. **Detailed Design & Site Assessment:** Conduct a 30% design phase evaluation, including structural assessment of the roof, electrical interconnection details, and shading analysis
2. **Vendor Quotations:** Obtain updated vendor quotes for PV system equipment, installation, and interconnection to refine cost estimates beyond NLR benchmarks
3. **Permitting & Interconnection:** Coordinate with Southern California Edison (SCE) to complete the interconnection study and ensure compliance with NEM 3 tariff rules
4. **Finalize Incentive Applications:** Submit applications for the 30% ITC (direct pay) to secure federal funding and reduce upfront capital cost
5. **Procurement & Installation:** Issue RFPs for procurement and construction, selecting qualified contractors with experience in municipal PV installations
6. **Commissioning & Monitoring:** Upon installation, perform commissioning tests, integrate the system with monitoring platforms, and establish an operations and maintenance (O&M) plan to ensure reliable long-term performance

Appendix

Incentive Programs

This section outlines how the incentive programs function and provides relevant information about them. Specific application of these programs to presented scenarios is explored in previous sections.

Inflation Reduction Act

The Inflation Reduction Act of 2022 stands as a significant piece of legislation designed to strengthen the United States' commitment to fighting climate change by making considerable investments in renewable energy. A key feature of the Inflation Reduction Act is its financial incentives, namely the Investment Tax Credit (ITC) and the Production Tax Credit (PTC), which aim to accelerate the adoption of renewable energy technologies.

The ITC allows for a significant tax credit for investments in renewable energy technologies, including solar panels and wind turbines, directly reducing the upfront cost of these systems. This makes renewable projects more financially viable and attractive to investors and consumers alike. On the other hand, the PTC provides a per-kilowatt-hour tax relief for the production of energy from renewable sources, incentivizing the operation and expansion of renewable energy facilities.

Notably, Inflation Reduction Act programs have been subject to change in recent legislation. Presented here are active opportunities as of the time of the report.

Production Tax Credit

The Production Tax Credit (PTC) within the framework of the Inflation Reduction Act offers considerable financial incentives for renewable energy projects, primarily designed to decrease the federal income tax liability based on the electricity produced per kilowatt-hour.

The PTC directly reduces the federal income tax for taxable entities. Furthermore, for non-taxable entities such as local governments, educational institutions, or nonprofit organizations, the PTC allows these credits to be monetized, facilitating their involvement in renewable energy initiatives. This provision is applicable for projects that become operational between January 1, 2023, and December 31, 2032, providing a broad window for planning and implementation.

Projects located in designated low-income energy communities receive further incentives. The PTC is structured to be claimable annually for a decade from the start date of operations of the qualifying renewable system, providing long-term financial support. This current structure of the PTC is set to continue through the end of 2024. Starting from January 1, 2025, the credit system will transition to a technology-neutral format, broadening the scope to include a wider array of technologies and fostering a more inclusive approach to renewable energy incentives.

As of the date of this report, the program is still active but solar projects must have “begun construction” by July 4, 2026.

The City project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

Investment Tax Credit

The Investment Tax Credit (ITC) established under the Inflation Reduction Act offers a powerful incentive for deploying renewable energy technologies by providing a reduction in federal tax liability. This reduction is calculated as a percentage of the capital investment made in eligible energy systems. Taxpayers can apply the ITC to their federal income tax for the year the technology is installed, significantly decreasing their tax burden.

Starting January 1, 2023, special provisions enable tax-exempt entities such as local governments and nonprofits to receive direct payments equivalent to the value of the credit. This arrangement improves the liquidity and financial feasibility of renewable projects for these organizations. The scope of eligible technologies under the ITC is broad, encompassing solar panels, wind turbines, fuel cells, and other renewable energy systems.

As of 2025, the Investment Tax Credit (ITC) for solar projects is set at 30% of the eligible costs, encompassing both the equipment and installation expenses. This rate is scheduled to decrease to 26% in 2033 and further to 22% in 2034. Systems rated under 1 megawatt (MW) qualify for the full 30% without having to comply with additional requirements; larger systems will only receive the full amount if they meet specific labor requirements. These include paying prevailing wages to workers during construction and using apprentices to perform a portion of the total construction hours (15% after 2023). Bonus credits are available based on site location, e.g. low-income communities.

The ITC is set to continue delivering these benefits at its current rate until 2032, contingent upon meeting the specific project criteria laid out in the act. Looking ahead, post-2024, the ITC will transition to a technology-neutral system, which will be applicable to all zero-emissions technologies, reflecting a shift towards a more inclusive and adaptable approach to supporting renewable energy development.

HHZP project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

As of the date of this report, the program is still active but critical deadlines for project eligibility and complete operability are quickly approaching in 2026 and 2027, respectively.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) offers financial incentives to non-residential customers of utility Company to encourage the adoption of energy storage systems. These systems help businesses prepare for power outages that may occur due to weather, emergencies, or other unforeseen events. The SGIP funding is authorized through 2024, with incentives structured to decrease over time as funding milestones are reached or as more participants enter the program.

Non-residential customers have access to three types of SGIP rebates: General Market, Equity, and Equity Resilience. Furthermore, SGIP incentives are significantly higher for vulnerable or disadvantaged communities through the Equity and Equity Resilience categories.

Incentives are typically paid upfront for residential systems upon project completion and site verification, while nonresidential systems may receive half upfront with the balance paid based on the system's performance over time. Eligibility for SGIP incentives extends to residential, commercial, industrial, agricultural, and municipal customers of specific utilities including Pacific Gas & Electric, Southern California Edison, SoCalGas, San Diego Gas & Electric, and those managed by the Center for Sustainable Energy.

To be eligible for this rebate, a facility must satisfy two conditions: firstly, it must fall under the category of a government agency, educational institution, non-profit organization, or small business. Secondly, it must fulfill at least one of the following requirements: be located in a Disadvantaged Community (DAC), be situated in a census tract where the Median Household Income of the Statewide Median Income or be situated in California Indian Country.

On the other hand, the equity resilience rebate offers a rate, covering a percentage of the cost of an average energy storage system. To qualify for this rebate, a facility must meet certain requirements. Firstly, it must have experienced two or more utility Public Safety Power Shut-offs (PSPS), or it should be located in a Tier 2 or 3 High Fire Threat District (HFTD) and serve customers in DACs or Low Income Communities. Secondly, it must fulfill at least one of the following additional criteria:

- Be a police station, fire station, emergency response provider, emergency operations center, 911 call center, medical facility, private and public natural gas, electric, water, wastewater, or flood facility, jail or prison, utility-designated PSPS assistance center, cooling center, homeless shelter.
- Be a grocery store, supermarket, or corner store with less than $15 million in annual gross receipts.

- Be an Independent Living Center or a Food Bank.

Modeling Assumptions

The modeling conducted for this feasibility study was based on standard industry benchmarks, available site data, and conservative assumptions to ensure realistic projections. The following key assumptions were applied:

1. **Energy Consumption Baseline** – Historical hourly load data (8,760 points) from the facility was consolidated to represent a typical annual profile. This served as the reference for sizing PV and BESS systems.
2. **PV System Costs** – Capital expenditure (CAPEX) and operations and maintenance (OPEX) values were derived from the National Laboratory of the Rockies (NLR) 2024–2025 benchmarks for commercial rooftop systems. PV CAPEX was assumed at $1.75–$2.00/Wdc, with OPEX at ~$19/kW-year.
3. **BESS Costs** – Battery energy storage CAPEX was modeled using NLR 2025 benchmarks at ~$350/kWh. OPEX was assumed at ~$40/kW-year, covering maintenance, monitoring, and lifecycle management.
4. **ITC Incentives** – A 30% Investment Tax Credit (direct pay) was assumed, reducing upfront project cost. No additional low-income or disadvantaged community adders were included, since the site does not qualify.
5. **Performance Parameters** –
    - PV generation modeled with HelioScope using site tilt, azimuth, and shading factors.
    - Battery modeled with 90% round-trip efficiency and daily cycling where applicable.
    - Energy inflation rate of 3% annually applied to utility costs.
6. **Utility Tariff** – The analysis used the most recent Southern California Edison tariff, **TOU-GS-2 Option D**, as published in the file *ELECTRIC_SCHEDULES_TOU-GS-2_2025*. It was assumed under the current **NEM 3** framework. Exported PV energy was valued at ~25% of retail rate. Since tariff structures and prices are subject to future changes, the financial outcomes presented here should be viewed as indicative estimates rather than fixed projections.
7. **Infrastructure** – Electrical interconnection feasibility was preliminarily evaluated using customer-provided single-line diagrams. Minor breaker adjustment (600 A to 500 A) was assumed to comply with NEC 705.12 120% busbar rule for PV backfeed.
8. **Environmental Impact** – Greenhouse gas (GHG) reduction estimates were calculated using EPA eGRID emission factors for the CAMX subregion, applied to modeled PV generation.

Disclaimer: These figures are rough estimates intended for feasibility-level evaluation. If more precise values are required, additional detail must be developed through site-specific engineering, vendor quotations, and utility coordination during the advanced design phase.

Net Energy Metering

Net Energy Metering (NEM) in California is a billing arrangement that allows residential and commercial customers who generate their own electricity, primarily through solar photovoltaic (PV) systems, to receive credit for the surplus energy they contribute to the grid. This system is designed to incentivize the use of renewable energy sources by offsetting the cost of electricity consumption with the energy produced by these installations.

Under NEM, when a solar system generates more electricity than is consumed, the excess energy is sent back to the utility grid, and the customer earns credits. These credits can then be used to offset the cost of energy drawn from the grid when the solar system isn't producing enough to meet the customer's demand, like during nighttime or cloudy days. The rules, rates, and credits under NEM can vary over time, with different iterations such as NEM 1, 2, and the latest NEM 3, each having specific regulations and compensation structures for solar energy production and exchange.

The transition from NEM 2 to NEM 3 in California, which was effective on April 14, 2023, introduced significant changes in the net metering policies for utility customers with photovoltaic (PV) systems. These changes impact

several aspects, particularly the economics of energy arbitrage between PV system owners and the utility. Here's a summary of the key changes:

1) **Reduction in Export Rates:** Under NEM 3, there's a substantial reduction in the rates for excess electricity exported onto the grid by solar systems. This rate has been reduced by approximately 75%, thereby lowering the overall savings for home solar systems and increasing the payback period. This change is a shift from the traditional one-to-one offset of net metering policies, where the price of a kWh of electricity pushed onto the grid was equal to the price of a kWh pulled off the grid.
2) **Implementation of Electrification Rates:** Customers enrolling in NEM 3 are required to use electrification rates instead of regular Time-of-Use (TOU) rates. These electrification rates feature higher on-peak charges and lower off-peak charges, along with a fixed charge of $15 per month. The peak rate period remains from 4 pm to 9 pm.
3) **Export Compensation Based on Avoided Cost Calculator (ACC):** Export compensation under NEM 3 is determined by California's ACC, with specific export rates for every combination of Month, Hour, and Weekday or Weekend. The export value is lowest in the middle of the day when solar energy is abundant on the grid and highest during peak summer demand periods. Notably, the export rates are significantly lower than retail rates during the hours when PV systems are most productive (10 am – 3 pm). To maintain the financial viability of solar PV systems, customers in PG&E and SCE service territories receive an adder on top of the ACC rate, ranging between 2.2 and 9 cents depending on location and customer class.
4) **Shift to a Cost Avoidance System:** NEM 3 introduces a cost avoidance system for exported electricity. This system pays customers the lowest amount a company can pay under the Public Utility Regulatory Policies Act of 1978 (PURPA), which is significantly less than the typical retail rate. This results in customers receiving, on average, 75% less for the electricity they sell back to the grid, with rates varying by month and by hour.
5) **Grandfathering NEM 2 under NEM 3:** Under the recent NEM 3 policy in California, existing customers with a photovoltaic (PV) system installed under NEM 2 can retain the benefits and terms of their NEM 2 agreement, a process known as "grandfathering." However, these customers are restricted from replacing or adding capacity to their PV systems if they wish to maintain their NEM 2 status, as any significant modifications would require transitioning to the terms of NEM 3.

The Net Energy Metering (NEM) 3.0 policy introduces transformative changes, particularly enhancing the value of utilizing Battery Energy Storage Systems (BESS) for owners of solar power systems. A significant aspect of NEM 3.0 is the reduction in compensation rates for surplus electricity fed back into the grid by solar systems, now down to 75%. This adjustment shifts the financial dynamics, making it less lucrative to export excess solar energy to the grid. Instead, storing this surplus energy in a BESS and utilizing it when energy costs are higher becomes a more financially savvy approach.

The utility of BESS extends beyond merely optimizing the use of solar energy. It offers several additional advantages, such as providing backup power during utility blackouts, mitigating charges associated with demand peaks, and enabling energy arbitrage. Energy arbitrage under this system allows for the charging of BESS not only with excess solar energy but also with cheaper grid energy during low-cost periods. This stored energy can then be used in lieu of more expensive grid power at peak times, effectively reducing reliance on utility-supplied energy. Consequently, NEM 3.0 not only promotes more efficient use of solar energy but also broadens the scope of BESS applications, contributing to a more versatile and resilient energy management strategy.

AECOM



Microgrid Feasibility Study
City of Banning

Site:
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125 East Ramsey Street, Banning, CA 92220

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Delivering a better world

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Executive Summary

This study appraises the viability and benefits of distributed energy resource implementation scenarios at the subject site. Four scenarios were developed and compared, with key metrics summarized below:

Case	Components	CAPEX ($)	Utility Savings (kWh)	Annual Bill Savings ($)	Payback Period (years)	GHG Reduction ($MTCO_2e$/year)
1	PV	~$366k	~43%	~$17k	~50	~105
2	PV + BESS	~$471k	~44%	~$17.5k	~43	~105
3	BESS	~$70k	—	—	—	—
0	Business-as-usual	$0	—	—	—	—

Note: All values are approximate and subject to final design and incentive approval.

- **Case 1: Photovoltaic (PV) array** – Introduces new onsite generation and reduces utility consumption but requires significant upfront capital and results in an extended payback period under the current rate schedule. AECOM understands that the existing PV array affixed to the carport on the east side of the property is not currently functioning. As such, this modeled scenario assumes replacement equipment at the same and additional locations.
- **Case 2: PV plus battery energy storage system (BESS)** – Increases self-consumption and reduces grid reliance further; however, the incremental savings do not proportionally offset the added cost and complexity of storage.
- **Case 3: BESS-only** – Provides limited resilience benefits and is potentially redundant given the presence of existing backup generation; its value cannot be confirmed without a more detailed backup capacity assessment.
- **Case 0: Business-as-usual** – Maintains the current operating condition, leveraging a flat and comparatively low-cost utility rate schedule with no additional capital investment.

Considering the above, and based on the site's existing backup infrastructure, flat rate utility rate schedule, relatively low energy costs compared to broader market conditions, and extended payback periods associated with new investments, this study concludes that remaining in **Case 0** may be the most pragmatic path forward at this time. Under current conditions, given the existing generator set in-place, neither PV-only (Case 1) nor PV + BESS (Case 2) scenarios deliver sufficient financial return to justify the required capital outlay, and the incremental resilience benefits may not outweigh the associated costs.

Recommended Next Steps

1. Maintain current operations under the existing utility rate schedule and infrastructure configuration.
2. Monitor utility rate schedule changes, rate escalations, and demand charge structures that could materially alter project economics.
3. If resilience requirements increase, conduct a focused evaluation of existing backup generation to verify critical load coverage and runtime adequacy before considering a BESS-only solution.
4. Track federal and state incentive program updates that could improve the financial viability of future PV or storage investments.
5. Reassess distributed energy resource options if market conditions, regulatory requirements, or site operational priorities change.

The objective of this recommendation is to avoid long-horizon investments with limited return and retain flexibility to pursue distributed energy and targeted resilience solutions when conditions become demonstrably favorable.

Background

Purpose

In recent years, especially within the past decade, the impacts of extreme heat and wildfires have been profound through the Inland Empire. Power service disruptions have been increasing in frequency and severity throughout Riverside County, affecting the availability of essential services and community resources.

In 2023, the Western Riverside Council of Governments (WRCOG) received an award (Grant Agreement OPR23145) from the Adaptation Planning Grant Program of the California Governor's Office of Land Use & Climate Innovation Integrated Climate Adaptation and Resilience Program. This program provides funding to help fill local, regional, and tribal planning needs, provides communities the resources to identify climate resilience priorities, and supports the development of a pipeline of climate-resilient infrastructure projects across the state.

As part of this grant-funded project, the Energy Resilience Plan 2.0, WRCOG commissioned microgrid feasibility studies for its member agencies. These studies serve to provide valuation of a potential microgrid at a community-essential facility, as designated by the member agency.

The site selected for the City of Banning is the Banning Police Department located at 125 E Ramsey Street, Banning, CA 92220.

This study presents key insights and findings from the evaluation of distributed energy resource (DER) scenarios, including photovoltaic (PV) array and battery energy storage system (BESS) components, at the subject site. It includes analysis of the site's historic energy demand profile and appraises potential PV array and BESS sizing and siting scenarios accordingly. Notably, the study includes assessment of the generation and storage requirements to support the site's critical loads to enable resilience for a specified number of hours during power service disruptions.

Furthermore, this study outlines the financial implications of self-generation, including estimated cost savings, return on investment (ROI), and potential financing options for the project.

It is important to note that this study serves as a preliminary technical and financial assessment. Its purpose is to provide the City of Banning with the information to make an informed decision on whether to proceed to next phases of microgrid implementation before committing to detailed engineering design and further investment.

Adaptation Planning Grant Program

As communities in California experience more frequent, prolonged, and severe impacts from climate change, communities and governments at all scales are developing strategies and implementing actions to build a climate-resilient future. However, many jurisdictions, especially under-resourced communities in California, lack the capacity, tools, guidance, and resources to effectively prepare for climate impacts.

The Adaptation Planning Grant Program addresses this capacity gap by providing funding to help fill planning needs, providing communities with the resources to identify climate resilience priorities, and supporting the development of climate resilience projects across the state. The Adaptation Planning Grant Program enables communities to climate risk and adaptation considerations into planning activities and prepare for climate readiness and resilience in the long term.

The Adaptation Planning Grant is part of the Integrated Climate Adaptation and Resiliency Program (ICARP) housed within the Governor's Office of Land Use and Climate Innovation. ICARP advances statewide climate adaptation and resilience by coordinating investments, partnerships, and climate science to ensure people, natural systems, and the built environment are protected, prepared, and thrive in the face of climate change.

Through direct and equity-focused investments and resources, ICARP helps build climate adapted and equitable communities in California, with a focus on solutions that address the impacts of climate change and reduce greenhouse gas emissions. ICARP works to advance these priorities across all levels of government by developing

actionable science and research; providing guidance, tools, and technical assistance; and administering climate resilience-focused grant programs.

Learn more: https://lci.ca.gov/climate/icarp/

Modeling Methodology

This section defines the criteria for sizing the PV array and BESS system components, detailing general parameters, technical requirements, and expected performance criteria.

PV Modeling

1. **Data Inputs**
    - **Solar Resource**: Hourly or sub-hourly irradiance data (e.g., typical meteorological year or on-site measurements)
    - **Site-Specific Factors**: Tilt angle, azimuth, shading analysis, and available roof/ground space
2. **Simulation Approach**
    - Use of HelioScope software to estimate hourly PV production
3. **Sizing Criteria**
    - **Capacity Target**: The sizing criteria are based on 85% of the facility's current annual energy consumption. This approach aims to offset the facility's energy usage with the PV array. However, the final system capacity is constrained by the area designated as available by the client.
    - **Performance Ratio**: Evaluate Performance Ratio to ensure consistent system output
    - **Energy Production**: Hourly, daily, monthly, and annual PV generation forecasts
    - **Load Matching**: Amount of PV energy that directly offsets site load vs. excess exported to the grid

BESS Modeling

1. **Data Inputs**
    - **Load Profile**: Detailed electricity consumption and demand patterns
    - **PV Production Profile**: From the PV modeling results
    - **Energy Duration for Resilience**: Determine the critical loads that the BESS will support during islanding operations
2. **Operational Modes**
    - **Energy Shifting / Excess PV Storage**: Battery charges when PV output exceeds site demand, discharges when site demand is high.
    - **Resilience (Standalone BESS)**: Sized to support critical loads during outages
3. **Sizing Criteria**
    - **Capacity (kWh)**: Based on required autonomy (energy shifting, peak shaving, or resilience duration)
    - **Max Discharge/Charge Rate (kW)**: Aligned with site load peaks, PV generation surpluses, and emergency power needs
4. **Simulation Approach**
    - Hourly or sub-hourly dispatch modeling to maximize economic benefit (e.g., demand charge reductions or avoided peak rates)

- Incorporate battery round-trip efficiency, self-discharge, and operational constraints (e.g., partial charge strategies)

5. **Output**

   - **Discharge/Charge Profiles**: Hourly modeling of how the battery is utilized
   - **Cost Savings**: Reduction in energy and demand charges or avoided grid cost
   - **Backup Duration**: If sized for resilience, the total hours/days of critical load coverage

Assumptions

AECOM collected facility data through a request for information process. Energy consumption factors and facility characteristics were identified and integrated in analysis. AECOM used these combined datasets to confirm energy utility consumption baselines.

In performing the analysis, AECOM made the following assumptions:

- This feasibility assessment refers to the Banning Police Department, located at 125 East Ramsey Street, Banning, CA 92220.
- Since the client did not have an available 8760 hourly dataset, the monthly and annual electricity consumption pattern was derived from customer-provided utility bills using an AECOM tool algorithm that extrapolates the billing data to generate a simulated 8760 load profile.
- AECOM utilized the Levelized Cost of Energy (LCOE) for the installed cost per watt of PV installations and BESS, as sourced from the National Laboratory of the Rockies (NLR). This data was used to estimate the hypothetical cost of installing the PV array and BESS at the site, as detailed in this feasibility assessment. For an accurate cost estimation, it is necessary to obtain vendor quotes, which are subject to change due to market-dependent time windows. These quotations are typically conducted during the 60% design phase, at which point there is an understanding of the specific equipment ratings and brands to be used.
- This feasibility assessment evaluates the site's existing electrical infrastructure using customer-provided data on the main breaker and bus capacity, as documented in the client-provided file AECOM has assessed whether the existing electrical system can support the proposed PV array and BESS installation. However, as this is a feasibility study, an on-site assessment is required for a definitive determination. A site visit should be conducted during the advanced design phase, typically at the 30% design stage, to confirm site-specific conditions.
- AECOM has estimated the potential PV generation capacity based on areas that appear to be viable based on publicly available aerial photographs. However, a site assessment would be required in later project phases, typically at the 30% design stage, to ensure that the site has the necessary infrastructure for PV array installation. This includes evaluating civil structures, load-bearing capacity, particularly for rooftop installations, and other critical conditions necessary for successful implementation.
- At this time, AECOM is not in a position to verify the location, condition, or capacity of existing conduit (e.g., recent roof construction).
- This feasibility assessment uses a regionalized estimate of general production (kWh) to calculate the amount of greenhouse gas emissions avoided through PV generation. The calculation is based on the U.S. EPA Emissions & Generation Resource Integrated Database (eGRID).
- This feasibility assessment clarifies that other charges such as connection fees, required service charges, and taxes remain unchanged. The analysis focuses solely on the bill components directly affected by the installation of PV and BESS under the NEM 3 framework.

AECOM utilized the following tools in conducting the analysis:

- AECOM Internal Tools: Proprietary tools developed by AECOM for analyzing energy patterns and evaluating system performance in simulated environments. These tools are designed to assess energy costs for applications such as peak shaving, energy trading, etc. in DER implementations.
- HelioScope: Web-based software tool used for the design and performance analysis of photovoltaic systems. It combines system layout design with energy simulation, allowing users to model rooftop, ground-mounted, and canopy PV installations. The software factors in module placement, tilt, azimuth, shading, and local weather data to provide accurate estimates of system capacity and expected energy generation.

Site Information

This study is conducted for Banning Police Department, located at 125 East Ramsey Street, Banning, CA 92220. The site currently consumes about **603,400 kilowatt-hours (kWh) per year**,

The facility is served by a 480/277-volt (V), three-phase electrical distribution system centered on a 1200-ampere (A) main switchboard, which acts as the primary aggregation point for utility service and on-site generation. The site integrates a grid-tied photovoltaic system rated at 50 kilowatts (kW) alternating current (AC) through a dedicated three-pole 225 A interconnection breaker, ensuring full compliance with NEC interconnection and protection requirements while maintaining operational separation from the core facility loads.

The existing photovoltaic system is built around a single 480 V Advanced Energy inverter with dedicated direct current (DC) and alternating current (AC) isolation, utility-grade metering, and clearly defined points of disconnection. At the DC level, the array architecture is segmented through combiner-based string aggregation, providing balanced current collection, fault isolation, and maintainability. String and combiner protection are conservatively sized, maintaining voltage and current margins within equipment ratings under worst-case environmental conditions.

From an operational standpoint, the electrical configuration reflects a conventional commercial service with centralized protection, copper conductors, and clearly defined isolation boundaries between utility power and on-site generation. The PV system operates strictly as a grid-interactive asset, contributing energy offset during normal operation without providing inherent resilience or islanding capability to the facility.



Figure 1. Site Location

Incentive Programs

AECOM has identified three key incentive programs that could benefit the subject site, focusing on renewable energy production and advanced energy storage systems.

The Investment Tax Credit (ITC) and Production Tax Credit (PTC) are federal incentives that reduce the cost of renewable energy projects. ITC offers a tax credit based on a percentage of upfront investment costs, while PTC provides a per-kilowatt-hour credit for electricity generated over time.

Production Tax Credit

Under this initiative, the project is eligible for a tax credit ranging from 0.3 cents to 1.5 cents per installed kWh. The specific value of the credit is determined by several factors, including the project's adherence to certain requirements such as complying with labor standards and using domestic materials.

The PTC program pays for each kilowatt-hour produced over a 10-year period, with government entities receiving the benefit as direct pay instead of a tax credit. For this project, with an estimated 540,195 kWh per year, the best case at 1.5 ¢/kWh would yield about $8,103 annually, totaling around $81,030 over 10 years.

Investment Tax Credit

The City may utilize either the ITC or the PTC, but not both. Because the project has not yet begun construction, the ITC remains the preferred alternative. In this scenario, the project is assumed to be located within a qualifying low-income census tract, enabling eligibility for the additional 10 percent bonus credit.

Under the Low-Income Communities Bonus Credit Program, projects located within a designated low-income community, as defined by the 2016–2020 census tract boundaries in Figure 3, receive an additional 10 percentage points added to the base ITC. This increases the total credit from 30 percent to 40 percent of the eligible project cost.

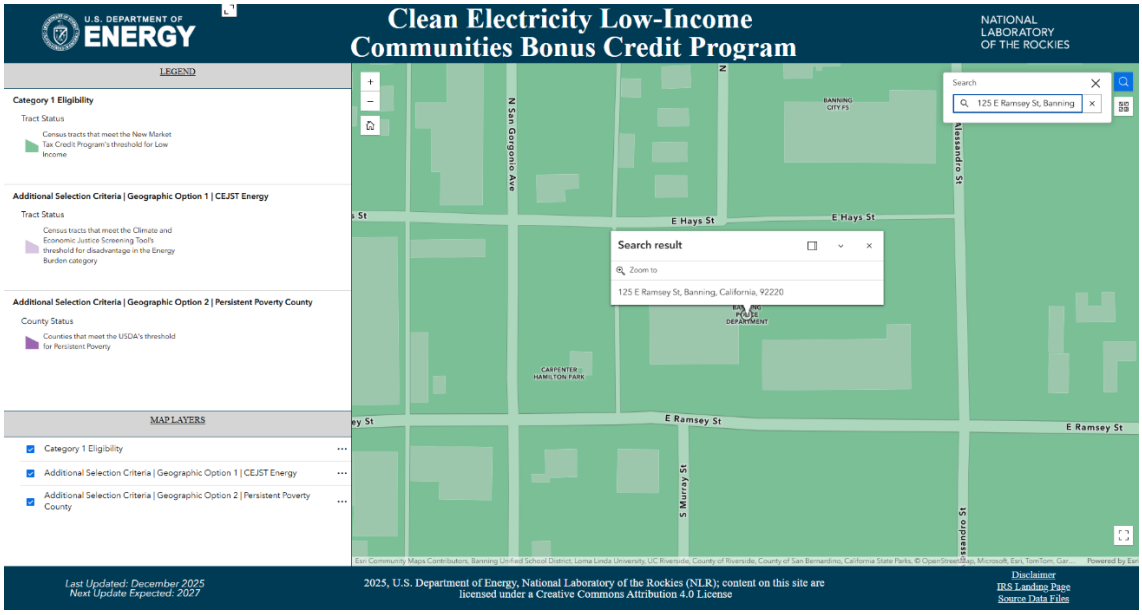


Figure 2. Clean Electricity Low-Income Communities Bonus Credit Program Map

Using NLR's capital expenditure (CAPEX) range of $1.75-2.00/W DC, the proposed 305 kW DC PV system would cost between $533,750 and $610,000. With a 40 percent ITC, the resulting direct-pay benefit increases to $213,500 - $244,000, reducing the project's upfront capital requirements accordingly.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) is California's primary incentive designed to reduce the upfront cost of energy storage systems. The program has three levels:

- **General Market**: For projects located outside Disadvantaged Communities (DAC). Typical incentive: $0.10/Wh.
- **Equity (DAC):** For projects located within a DAC. Incentive: $0.85/Wh.
- **Equity Resilience:** For critical facilities within a DAC and in PSPS or high fire-risk zones. Incentive: $1.00/Wh.

In Case 1, the project site is outside a DAC, so it only qualifies for the General Market level. Using an NLR-based cost of $450/kWh, a 300-kWh battery would cost approximately $135,000. With the General Market incentive of $0.10/Wh, the project would receive about $30,000, resulting in a net battery cost of roughly $105,000.

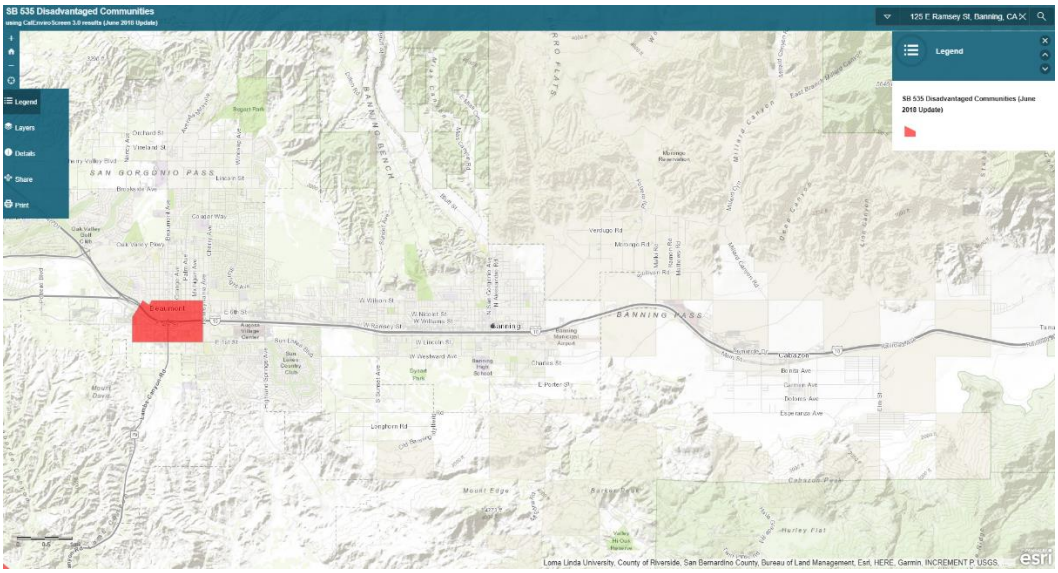


Figure 3. SB 535 Disadvantaged Communities Map

Scenarios & Analysis

Case 0: Current Situation (Baseline)

Rate Schedule & Contract Type

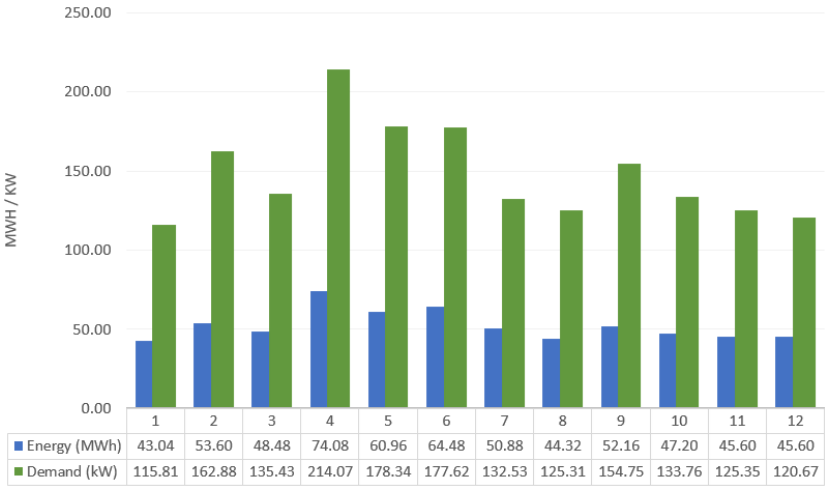
The site is currently served by City of Banning Electric Utility under the Medium Commercial (MC-1) rate schedule. This rate schedule separates costs into energy charges (based on kilowatt-hours consumed) and demand charges (based on the highest kilowatt demand registered during the billing cycle). In addition, prices vary by time-of-use periods—on-peak, mid-peak, and off-peak—so the timing of energy use significantly affects overall costs.

Being on this rate schedule means the site's operating expenses are directly tied not only to how much energy is consumed but also to when it is consumed and how high the peak demand reaches.

The rate schedule cost presents the costs as totals (delivery + bundle). The prices were used as the basis for this study. While they may fluctuate slightly month to month depending on market conditions, these variations are generally minor.

Monthly & Annual Energy Consumption and Demand

The facility currently consumes 630,400 kWh annually, with April being the highest month at about 74 MWh and January the lowest at about 43 MWh. In terms of demand, April records the peak at around 214 kW, while January is the lowest at about 115 kW. The following graph presents this historical data for the 2024–2025 period.



	1	2	3	4	5	6	7	8	9	10	11	12
Energy (MWh)	43.04	53.60	48.48	74.08	60.96	64.48	50.88	44.32	52.16	47.20	45.60	45.60
Demand (kW)	115.81	162.88	135.43	214.07	178.34	177.62	132.53	125.31	154.75	133.76	125.35	120.67

Figure 4. Historic Site Energy Profile

Monthly & Annual Energy Costs

The site currently spends about $40,048 per year in energy and demand cost, with approximately $5,548 in energy costs and $34,400 in demand charges, based on MC-1 rate schedule simulation. For this analysis, we are focusing only on energy and demand costs, as these are the components directly impacted by the installation of a PV system.

Case 1: PV Only

Installed Capacity & Location

AECOM understands that the existing PV array affixed to the carport on the east side of the property is not currently functioning. As such, these provided estimates assume replacement equipment at the same location.

The PV system for the site was sized to offset approximately 85% of current consumption, with the goal of fully offsetting present usage. The placement areas for the PV installation were identified according to customer requirements. The system capacity is estimated at 305 kW DC, with an expected annual production of about 540,195 kWh.

Figure 5 presents the modeled energy production throughout the year, and Figure 6 identifies the modeled PV installation areas on the site.

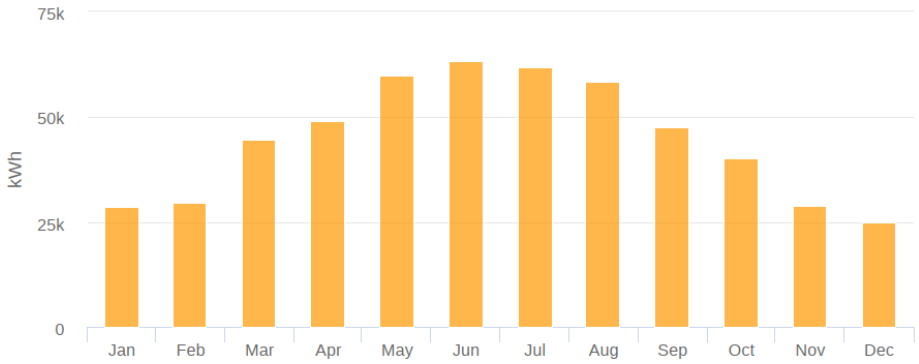


Figure 5. Modeled PV Production



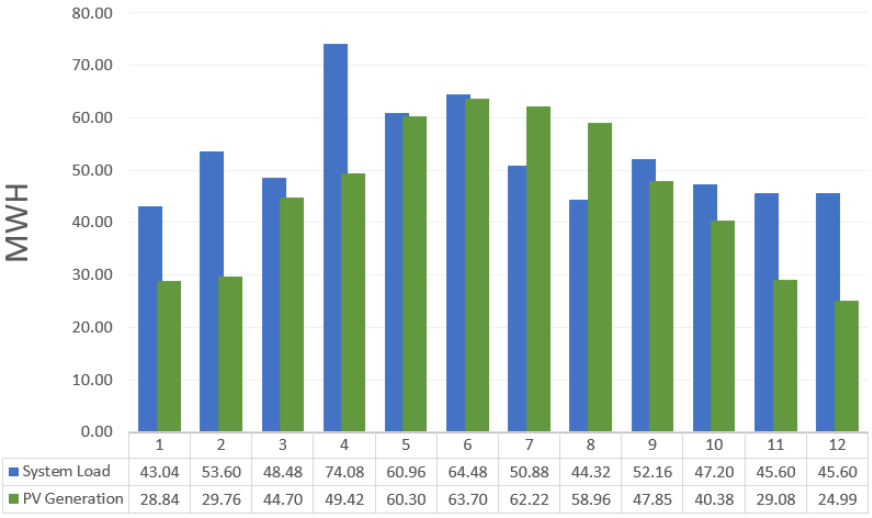
Figure 6. Modeled PV Installation Areas

Modeled PV Production

The modeled PV system is projected to generate an average of 45,016 kWh per month, with an estimated annual production of 540,195 kWh.

This scenario doesn't include a BESS, so the excess energy produced need be exported to the utility, which requires entering a Net Energy Metering (NEM) contract with the utility service provider. Under the currently available NEM rate schedule, NEM 3.0, exported electricity is credited at dynamic rates that vary by month, hour of day, and weekday, ranging from as low as $0.01/kWh during midday hours to over $1.00/kWh during peak evening hours in high-demand months like August and September. This study has calculated projected benefits from this arrangement.

Figure 7 compares historic monthly energy consumption and modeled PV generation. Not all solar energy will be consumed on-site, as excess daytime production may exceed demand and be exported to the grid, while nighttime demand cannot be covered since there is no generation after sunset and no battery to store the excess in this scenario.



	1	2	3	4	5	6	7	8	9	10	11	12
System Load	43.04	53.60	48.48	74.08	60.96	64.48	50.88	44.32	52.16	47.20	45.60	45.60
PV Generation	28.84	29.76	44.70	49.42	60.30	63.70	62.22	58.96	47.85	40.38	29.08	24.99

Figure 7. Modeled PV Output vs. Site Demand

Capital Expenditures

Based on NLR benchmark CAPEX values for commercial rooftop solar, the estimated cost to install a 305 kW DC PV system in Riverside County, California falls in the range of $1.75 to $2.00 per watt DC. This translates to a total investment of **approximately $533k – 610k for the complete system**.

These figures include typical equipment, installation, and soft costs, reflecting average market conditions for commercial-scale projects. Actual costs may vary slightly depending on site-specific conditions such as roof structure, permitting, interconnection requirements, and labor. However, the NLR benchmarks provide a reliable basis for estimating the capital cost of a system of this size and type in the region.

Operating Expenses

According to NLR's 2024 benchmark data, the annual operations and maintenance (OPEX) cost for commercial rooftop PV systems is about $19 per kW-DC. For a 305 kW DC system, this translates to an estimated **yearly OPEX of roughly $5,795** covering routine maintenance, monitoring, and related operational expenses.

Economic Metrics

The analysis shows that installing a PV system at the site under NEM3 provides measurable financial benefits by offsetting both energy and demand charges. Without solar, the facility currently spends about $40,048 annually on utility costs. With the PV system in operation, the energy cost is reduced to approximately $3,027 per year, while the demand cost drops to about $27,914 per year. In addition, the system generates excess electricity during the day that cannot be fully consumed on-site. Under NEM3 rules, this exported energy represents an additional benefit of roughly $7,988 annually.

Taken together, these reductions and export credits bring the facility's total utility bill down to **$22,953 per year**, achieving an **overall savings of about 43%** compared to current expenses

Payback Period and Return on Investment

The financial analysis shows that without PV, the facility spends approximately $40,048 per year on utility costs. With a 305 kW DC PV system installed, the annual cost is reduced to about 22,953, resulting in yearly savings of roughly $17,094. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system is estimated at $610,000, but with the 40 percent ITC direct pay, the net investment is reduced to approximately $366,000. In addition, the system carries an annual OPEX of $5,795, which slightly offsets the yearly savings. Taking these factors into account, the project generates a net benefit of about $17,094 minus 5,795 per year after OPEX. This results in a simple payback period of approximately 23 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross Savings ($)	Net Savings after OPEX ($)	Cumulative Cash Flow ($)
1	17,094	11,299	-354,701
2	17,607	11,638	-343,063
3	18,135	11,987	-331,075
4	18,679	12,347	-318,728
5	19,240	12,717	-306,011
6	19,817	13,099	-292,912
7	20,411	13,492	-279,420
8	21,024	13,897	-265,524
9	21,654	14,313	-251,210
10	22,304	14,743	-236,467
22	31,800	21,020	-20,959
23	32,754	21,650	692

Table 1. Return on Investment w/ 3% Inflation: Case 1

Technical Feasibility

The site is served at 480/277 V, three phase, through a 1200 A switchboard where an existing PV system was intended to interconnect via a 225 A backfeed breaker. Based on the configuration shown, this existing PV installation is not operational and is not currently contributing energy to the facility.

From a capacity standpoint, the existing switchboard is already constrained by NEC 705 bus limitations. A 1200 A bus allows a maximum of 240 A of load-side backfeed under the 120 percent rule, which effectively consumes the available margin even before considering any new generation sources.

Interconnecting an additional 305 kW DC PV system at this same load-side location would exceed the allowable backfeed current at 480 V and is therefore not code-compliant using a simple breaker-based connection. The addition of a 300 kWh BESS would further increase source contribution at the point of interconnection and aggravate this constraint.

Given these conditions, establishing the new PV and BESS on the existing switchboard as load-side backfeed is not a viable path. The technically sound and code-compliant solution is a supply-side interconnection ahead of the main service disconnect or the addition of a dedicated service-rated PV plus BESS section designed for the combined source currents.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 540,195 kWh per year. Using the U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows

- Carbon dioxide (CO_2): 231,419.538 pounds (lbs) (104.970 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 232,283.850 lbs (105.362 metric tons) avoided annually
- Nitrogen oxides (NO_x): 179.345 lbs (81.349 kg) avoided annually
- Sulfur dioxide (SO_2): 10.804 lbs (4.901 kg) avoided annually

Case 2: PV + BESS

System Components

This scenario assumes the same PV array described in Case 1 and a BESS sized for surplus PV production. The day with the highest energy surplus in our simulation occurred on Aug 10, during which the PV system produced 2,116.98 kWh, the site consumed 1,376.25 kWh, and the resulting surplus was 740.72 kWh. For size the BESS, we ran several iterations based on the available surplus energy and applied an algorithm that simulates the charge and discharge cycles of one year. This techno-financial analysis indicates that the optimal BESS capacity is approximately 300 kWh.

This simulation factor ensures that, even with variations in production or demand, excess solar energy generated during the day can be stored and later used when PV production does not fully meet the site's demand. However, in this case the facility operates under a flat rate schedule, where the electricity price remains constant throughout the day. As a result, the BESS does not provide value for energy arbitrage or time-based energy shifting, and its contribution is limited primarily to minor peak shaving, which is minimal for this specific operating profile.

Modeled Energy Flows

By installing a 300 kWh battery, we ensure that all the energy generated on-site is consumed by the facility itself. The charge and discharge profile of the battery is designed so that any PV surplus during the day is immediately stored in the battery rather than exported to the grid. Later, if the site demand exceeds the PV generation while there is still energy stored in the battery, the deficit is supplied from the battery.

This operational strategy minimizes or even eliminates consumption from the utility, since the PV and battery combination is prioritized to cover the load at all times. On an annual basis, the system is expected to produce slightly more energy than the site requires, leaving a surplus of around 10%, but this excess is negligible in terms of the overall utility bill.

Capital Expenditures

According to NLR benchmark data, the capital expenditure (CAPEX) for a commercial-scale 305 kW DC rooftop PV system in Riverside, California is estimated at $366k under ITC incentive, based on installation costs of $1.75–2.00 per watt DC.

For storage, NLR's 2025 cost projections indicate a CAPEX of $450 per kWh for the high-cost scenario. Applying this benchmark to a commercial-scale 300 kWh battery system represents an investment of roughly $135k, and under the SGIP program this amount can cover $30k from the total cost, effectively funding 22% of the BESS system

Together, the combined CAPEX for the PV and BESS systems under ITC and SGIP program is estimated at $471k representing the expected upfront investment for a commercial PV + BESS project of this size.

Operating Expenses

According to NLR benchmark data, the OPEX cost for a commercial-scale 305 kW DC rooftop PV system is estimated at $5,795.

NLR data indicates an operating cost of approximately $4 per kW-year. For a commercial-scale 300 kWh battery system, this results in an annual OPEX of about $1,200.

Together, the **combined OPEX for the PV and BESS systems** is approximately **$6,995 per year**, covering routine maintenance, monitoring, and system management.

Economic Metrics

The analysis shows that installing a commercial-scale PV system paired with a 300 kWh battery under NEM 3 provides strong financial advantages by allowing a substantial portion of the solar energy produced by the PV system to be consumed on-site.

In several PV production exceeds the facility's demand, and the surplus can be stored in the BESS for later use. However, without a battery system, the facility cannot absorb all of this excess energy, since any unused generation

must be consumed the moment it is produced. This unused energy would otherwise need to be exported to the utility grid, where under current NEM rules it would be compensated at only about 25 percent of the retail electricity rate. Given that time-of-use pricing makes stored energy far more valuable during high-cost periods, it becomes financially preferable to store surplus solar rather than sell it.

Without a BESS, exporting this excess would generate $7,988 but the facility would still face an annual utility cost of $22,953 By contrast, installing the BESS reduces grid reliance and allows the facility to consume nearly all of its solar production, resulting in a slightly lower annual utility bill of $22,445

To remain conservative, this analysis assumes that 10% of annual energy costs remain due to general losses.

It is important to note that other charges — such as connection fees, requisite charges, and taxes — remain unaffected. This analysis focuses only on those bill components directly impacted by the installation of PV and BESS under the NEM 3 framework.

Payback Period and Return on Investment

The financial analysis shows that without PV + BESS, the facility spends approximately $40,048 per year on utility costs. With a 305 kW DC PV system and 300 kWh BESS system installed, the annual cost is reduced to about $22,445 resulting in yearly savings of roughly $17,602. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system under ITC and SGIP incentives is estimated at $471,000. In addition, the system carries an annual OPEX of $6,995 Taking these factors into account, the combined system generates a net benefit of about 10,607 per year after OPEX. This results in a simple payback period of approximately achieved within 29 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross-Savings ($)	Net-Savings after OPEX ($)	Cumulative Cash Flow ($)
1	17,602	10,607	-460,393
2	18,130	10,925	-449,468
3	18,674	11,253	-438,214
4	19,234	11,591	-426,624
5	19,811	11,938	-414,685
6	20,406	12,297	-402,389
7	21,018	12,665	-389,723
8	21,648	13,045	-376,678
28	39,099	23,561	-15,626
29	40,272	24,268	8,642

Table 2. Return on Investment w/ 3% Inflation: Case 2

Technical Feasibility

The existing one line shows a PV system interconnected through a dedicated inverter, DC combiner and AC disconnect with utility-required metering and labeling. The current configuration is sized around the existing inverter and associated conductors, disconnects, and protection devices.

Interconnecting an additional 305 kW DC PV system and a 300 kWh BESS will require new inverter and BESS power conversion equipment, with dedicated AC feeders and disconnecting means. Existing conductor sizes, conduit, and the 400 A AC disconnect shown are specific to the current system and must be re-evaluated, as they are not adequate for the increased combined PV and BESS contribution.

The new PV and BESS must tie in upstream of the existing PV disconnect and metering arrangement, maintaining the same utility-facing requirements: visible AC disconnects, performance metering, directory plaques, and warning signage. Protection coordination, grounding, and bonding must be updated to reflect the higher fault contribution and continuous output.

A revised one line diagram is required to clearly define the new point of interconnection, feeder ratings, breaker sizes, and protection scheme. This approach allows the PV and BESS to be integrated without overstressing existing equipment while maintaining NEC and utility compliance.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 540,195 kWh per year. Using the U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows

- Carbon dioxide (CO_2): 231,419.538 lbs (104.970 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 232,283.850 lbs (105.362 metric tons) avoided annually
- Nitrogen oxides (NO_x): 179.345 lbs (81.349 kg) avoided annually
- Sulfur dioxide (SO_2): 10.804 lbs (4.901 kg) avoided annually

CASE 3: BESS Only

Critical Load Identification

For a police department facility, emergency and legally required standby loads are governed by NEC 700 and NEC 701, with system performance requirements under NFPA 110 and fire alarm power continuity under NFPA 72. Based on typical police department functions, the critical load is estimated at 50 kW, representing approximately 25 percent of the total connected load. This includes egress and emergency illumination, fire alarm and life-safety systems, dispatch and communications equipment, security and access control systems, and other legally required standby loads necessary to maintain core public safety operations during a utility outage.

Required Backup Duration

For the site, maintaining continuous operation of alarm systems, emergency communications, lighting, and fuel dispensing is essential to guarantee mission readiness. According to NFPA 110 (Section 4.2 and 7.12.1), emergency power supply systems (EPSS) must provide a minimum of 2 hours of operation at full rated load. However, because police stations are classified as critical public safety facilities, most Authorities Having Jurisdiction (AHJs) and best practice guidelines require at least 4 hours of backup capacity to ensure firefighters can respond to emergencies during extended outages.

Battery Capacity & Infrastructure

The required battery energy capacity is derived by multiplying the critical load of 50 kW by the 4-hour duration, resulting in a required emergency energy capacity of 200 kWh. The required battery power rating is 50.0 kW, corresponding to the peak emergency demand. The BESS would need to be connected on the emergency side of the electrical system, coordinated with the existing automatic transfer switch to ensure separation between normal and emergency circuits. Integration would require verification of available bus capacity, appropriate overcurrent protection, and clear routing to emergency distribution equipment shown on the one-line diagram.

Capital Expenditures

Using cost benchmarks published by the National Laboratory of the Rockies (NLR), the estimated CAPEX for a 200 kWh / 20 kW battery energy storage system is **approximately $70,000**. This figure includes the battery cabinets, inverter/PCS, microgrid controller with ATS, installation, protections, and engineering.

Operating Expenses

The expected **OPEX** is about **$1,200 per year**, also based on NLR reference values. This covers preventive maintenance, monitoring software, and NFPA 110 testing requirements. Battery replacement is typically required after 10–12 years of service.

Return on Investment & Qualitative Benefits

While a conventional financial return cannot be directly applied to this case, the value of a BESS for a police department is framed in terms of resilience, reliability, and compliance. Such systems are designed to ensure uninterrupted operation of life-safety and mission-critical equipment during extended utility outages. The benefits include maintaining operational continuity, reducing safety risks, and ensuring compliance with NFPA 110, NFPA 70, and NFPA 72.

Technical Considerations

Key technical considerations include confirmation of available bus capacity for interconnection, compliance with the 120 percent load-side interconnection rule where applicable, and verification of breaker and feeder sizing for emergency circuits. Proper ATS coordination is required to maintain strict separation between normal and emergency systems. A short-circuit and coordination study is necessary to validate protective device performance, along with transfer-sequence verification between utility, generator, and BESS. If lithium-ion technology is used, UL 9540A evaluation and site-specific fire and ventilation considerations must be addressed to align with the electrical configuration shown in the drawings.

Decision Matrix and Scenario Comparison

In order to determine the most appropriate scenario for the site, four scenarios were developed and analyzed: business as usual (Case 0), installing a PV system only (Case 1), installing PV with a BESS (Case 2), and installing a BESS only (Case 3). Each case was evaluated in terms of resilience value, capital and operating expenditures, energy savings, payback period, and technical feasibility. The decision matrix summarizes the comparative performance of these options.

Criteria	Case 0: Baseline	Case 1: PV Only	Case 2: PV + BESS	Case 3: BESS Only
Resilience Benefit	None	Limited (daytime only)	Moderate (self-consumption, some coverage)	High (but redundant due to existing 125 kW generator)
CAPEX ($)	0	~$366k (after 40% ITC)	~$471k (after ITC + SGIP)	~$70k
OPEX ($/yr)	Current	~$5,795	~$6,995	~$800
Annual Utility Bill ($)	~$40k	~$23k	~$22.5k	~$40k (no reduction)
Annual Savings ($)	–	~$17k	~$17.6k	Minimal (non-financial)
Payback Period	–	~23 years	~29 years	No ROI
GHG Reduction	None	~105 $MTCO_2e$ avoided annually	Same as Case 1	None
Technical Feasibility	Already in place	Feasible but constrained by bus backfeed limits	Feasible with supply-side interconnection	Technically feasible but unnecessary

Table 3. Scenario Comparison

Conclusion

Based on the comparative analysis, **Case 0 (Baseline)** emerges as the most appropriate scenario under the site's current operating, economic, and rate schedule conditions. A key consideration is that the existing generator set, which is adequately sized, renders the resilience benefit of new distributed energy resources (i.e., PV, BESS) redundant. Another driver of this outcome is that the facility is served under a flat utility rate schedule with relatively low energy and demand costs compared to prevailing market rates, which materially limits the economic upside of onsite generation or storage investments. Under this rate schedule structure, opportunities for energy arbitrage, peak shifting, or time-based value capture are inherently constrained.

While Case 1 (PV-only) and Case 2 (PV + BESS) provide measurable reductions in utility consumption and greenhouse gas emissions, both scenarios require significant upfront capital and result in extended payback periods that are not aligned with prudent investment thresholds for this facility. The low and flat cost of electricity reduces the marginal value of each kilowatt-hour offset, driving return on investment timelines that remain unattractive under current assumptions.

Case 3 (BESS-only) was also not selected at this stage. Although a battery system could theoretically enhance resilience, its incremental benefit is uncertain given the presence of existing backup power infrastructure. A BESS installed solely for backup purposes would require a more rigorous site-specific evaluation to confirm whether current backup capacity, runtime, and load coverage are insufficient. Absent such findings, the battery system would likely provide limited additional value relative to its cost.

Therefore, maintaining Case 0 may represent the most prudent course of action at this time. It avoids committing capital to long-horizon projects with weak financial performance, preserves operational simplicity, and maintains flexibility to reassess PV or storage options in the future should rate schedules increase, incentive structures improve, or resilience requirements change.

Summary of Strategy & Benefits

The selected strategy focuses on maintaining the existing configuration while deferring capital investment. This approach delivers the following outcomes:

- **Resilience Sufficiency:** Relies on existing backup power assets until a detailed resilience and critical load assessment demonstrates a clear gap.
- **Rate schedule Alignment:** Leverages a flat and comparatively low-cost utility rate schedule, which minimizes exposure to volatile energy pricing and reduces the financial value of onsite generation or storage.
- **Economic Discipline:** Avoids high upfront CAPEX associated with PV and PV plus BESS systems that exhibit payback periods exceeding acceptable investment horizons.
- **Risk Management:** Eliminates dependency on incentive programs, future rate schedule structures, and long-term performance assumptions that materially affect projected returns.
- **Operational Stability:** Maintains current operations without introducing new systems, controls, or maintenance complexity.
- **Future Optionality:** Preserves the ability to reevaluate PV and BESS solutions if utility rates rise, market conditions change, or regulatory and incentive frameworks become more favorable.

Next Steps

To proceed in a prudent and decision-aligned manner, the following next steps are recommended:

1. **Resilience Gap Assessment (Conditional):** If resilience capacity becomes a greater concern, perform a targeted evaluation of the existing backup power system to confirm actual critical load coverage, runtime capability, and operational constraints before considering a BESS-only solution.

2. **Maintain Current Operations:** Continue operating under the existing utility service and rate schedule structure, leveraging the site's flat and comparatively low-cost electricity rate while avoiding premature capital investment.

3. **Rate schedule & Cost Monitoring:** Periodically review utility rate schedule updates, rate adjustments, and demand charge structures to identify any future changes that could materially improve the economics of PV or BESS solutions.

4. **Deferred Technical Validation:** Defer detailed electrical interconnection studies, bus capacity evaluations, and protection coordination analyses until a clear economic or resilience driver justifies advancing beyond feasibility.

5. **Incentive Landscape Review:** Monitor federal and state incentive programs, including ITC adders and SGIP funding levels, to reassess project viability should incentive structures improve materially.

6. **Future Reassessment Trigger:** Revisit PV or PV plus BESS scenarios only if one or more of the following conditions occur: significant increases in utility rates, transition away from a flat rate schedule, major reductions in technology costs, or new regulatory or operational resilience requirements.

Appendix

Incentive Programs

This section outlines how the incentive programs function and provides relevant information about them. Specific application of these programs to presented scenarios is explored in previous sections.

Inflation Reduction Act

The Inflation Reduction Act of 2022 stands as a significant piece of legislation designed to strengthen the United States' commitment to fighting climate change by making considerable investments in renewable energy. A key feature of the Inflation Reduction Act is its financial incentives, namely the Investment Tax Credit (ITC) and the Production Tax Credit (PTC), which aim to accelerate the adoption of renewable energy technologies.

The ITC allows for a significant tax credit for investments in renewable energy technologies, including solar panels and wind turbines, directly reducing the upfront cost of these systems. This makes renewable projects more financially viable and attractive to investors and consumers alike. On the other hand, the PTC provides a per-kilowatt-hour tax relief for the production of energy from renewable sources, incentivizing the operation and expansion of renewable energy facilities.

Notably, Inflation Reduction Act programs have been subject to change in recent legislation. Presented here are active opportunities as of the time of the report.

Production Tax Credit

The PTC within the framework of the Inflation Reduction Act offers considerable financial incentives for renewable energy projects, primarily designed to decrease the federal income tax liability based on the electricity produced per kilowatt-hour.

The PTC directly reduces the federal income tax for taxable entities. Furthermore, for non-taxable entities such as local governments, educational institutions, or nonprofit organizations, the PTC allows these credits to be monetized, facilitating their involvement in renewable energy initiatives. This provision is applicable for projects that become operational between January 1, 2023, and December 31, 2032, providing a broad window for planning and implementation.

Projects located in designated low-income energy communities receive further incentives. The PTC is structured to be claimable annually for a decade from the start date of operations of the qualifying renewable system, providing long-term financial support. This current structure of the PTC is set to continue through the end of 2024. Starting from January 1, 2025, the credit system will transition to a technology-neutral format, broadening the scope to include a wider array of technologies and fostering a more inclusive approach to renewable energy incentives.

As of the date of this report, the program is still active but solar projects must have “begun construction” by July 4, 2026.

The City project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

Investment Tax Credit

The ITC established under the Inflation Reduction Act offers a powerful incentive for deploying renewable energy technologies by providing a reduction in federal tax liability. This reduction is calculated as a percentage of the capital investment made in eligible energy systems. Taxpayers can apply the ITC to their federal income tax for the year the technology is installed, significantly decreasing their tax burden.

Starting January 1, 2023, special provisions enable tax-exempt entities such as local governments and nonprofits to receive direct payments equivalent to the value of the credit. This arrangement improves the liquidity and financial feasibility of renewable projects for these organizations. The scope of eligible technologies under the ITC is broad, encompassing solar panels, wind turbines, fuel cells, and other renewable energy systems.

As of 2025, the Investment Tax Credit (ITC) for solar projects is set at 30% of the eligible costs, encompassing both the equipment and installation expenses. This rate is scheduled to decrease to 26% in 2033 and further to 22% in 2034. Systems rated under 1 megawatt (MW) qualify for the full 30% without having to comply with additional requirements; larger systems will only receive the full amount if they meet specific labor requirements. These include paying prevailing wages to workers during construction and using apprentices to perform a portion of the total construction hours (15% after 2023). Bonus credits are available based on site location, e.g. low-income communities.

The ITC is set to continue delivering these benefits at its current rate until 2032, contingent upon meeting the specific project criteria laid out in the act. Looking ahead, post-2024, the ITC will transition to a technology-neutral system, which will be applicable to all zero-emissions technologies, reflecting a shift towards a more inclusive and adaptable approach to supporting renewable energy development.

HHZP project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

As of the date of this report, the program is still active but critical deadlines for project eligibility and complete operability are quickly approaching in 2026 and 2027, respectively.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) offers financial incentives to non-residential customers of utility Company to encourage the adoption of energy storage systems. These systems help businesses prepare for power outages that may occur due to weather, emergencies, or other unforeseen events. The SGIP funding is authorized through 2024, with incentives structured to decrease over time as funding milestones are reached or as more participants enter the program.

Non-residential customers have access to three types of SGIP rebates: General Market, Equity, and Equity Resilience. Furthermore, SGIP incentives are significantly higher for vulnerable or disadvantaged communities through the Equity and Equity Resilience categories.

Incentives are typically paid upfront for residential systems upon project completion and site verification, while nonresidential systems may receive half upfront with the balance paid based on the system's performance over time. Eligibility for SGIP incentives extends to residential, commercial, industrial, agricultural, and municipal customers of specific utilities including Pacific Gas & Electric, Southern California Edison, SoCalGas, San Diego Gas & Electric, and those managed by the Center for Sustainable Energy.

To be eligible for this rebate, a facility must satisfy two conditions: firstly, it must fall under the category of a government agency, educational institution, non-profit organization, or small business. Secondly, it must fulfill at least one of the following requirements: be located in a Disadvantaged Community (DAC), be situated in a census tract where the Median Household Income of the Statewide Median Income or be situated in California Indian Country.

On the other hand, the equity resilience rebate offers a rate, covering a percentage of the cost of an average energy storage system. To qualify for this rebate, a facility must meet certain requirements. Firstly, it must have experienced two or more utility Public Safety Power Shut-offs (PSPS), or it should be located in a Tier 2 or 3 High Fire Threat District (HFTD) and serve customers in DACs or Low Income Communities. Secondly, it must fulfill at least one of the following additional criteria:

- Be a police station, fire station, emergency response provider, emergency operations center, 911 call center, medical facility, private and public natural gas, electric, water, wastewater, or flood facility, jail or prison, utility-designated PSPS assistance center, cooling center, homeless shelter.
- Be a grocery store, supermarket, or corner store with less than $15 million in annual gross receipts.

- Be an Independent Living Center or a Food Bank.

Modeling Assumptions

The modeling conducted for this feasibility study was based on standard industry benchmarks, available site data, and conservative assumptions to ensure realistic projections. The following key assumptions were applied:

1. **Energy Consumption Baseline** – Historical hourly load data (8,760 points) from the facility was consolidated to represent a typical annual profile. This served as the reference for sizing PV and BESS systems.
2. **PV System Costs** – Capital expenditure (CAPEX) and operations and maintenance (OPEX) values were derived from the National Laboratory of the Rockies (NLR) 2024–2025 benchmarks for commercial rooftop systems. PV CAPEX was assumed at $1.75–$2.00/Wdc, with OPEX at ~$19/kW-year.
3. **BESS Costs** – Battery energy storage CAPEX was modeled using NLR 2025 benchmarks at ~$350/kWh. OPEX was assumed at ~$40/kW-year, covering maintenance, monitoring, and lifecycle management.
4. **ITC Incentives** – A 30% Investment Tax Credit (direct pay) was assumed, reducing upfront project cost. No additional low-income or disadvantaged community adders were included, since the site does not qualify.
5. **Performance Parameters** –
    - PV generation modeled with HelioScope using site tilt, azimuth, and shading factors.
    - Battery modeled with 90% round-trip efficiency and daily cycling where applicable.
    - Energy inflation rate of 3% annually applied to utility costs.
6. **Utility Rate schedule** – The analysis used the most recent Southern California Edison rate schedule, **TOU-GS-2 Option D**, as published in the file *ELECTRIC_SCHEDULES_TOU-GS-2_2025*. It was assumed under the current **NEM 3** framework. Exported PV energy was valued at ~25% of retail rate. Since rate schedule structures and prices are subject to future changes, the financial outcomes presented here should be viewed as indicative estimates rather than fixed projections.
7. **Infrastructure** – Electrical interconnection feasibility was preliminarily evaluated using customer-provided single-line diagrams. Minor breaker adjustment (600 A to 500 A) was assumed to comply with NEC 705.12 120% busbar rule for PV backfeed.
8. **Environmental Impact** – Greenhouse gas (GHG) reduction estimates were calculated using EPA eGRID emission factors for the CAMX subregion, applied to modeled PV generation.

Disclaimer: These figures are rough estimates intended for feasibility-level evaluation. If more precise values are required, additional detail must be developed through site-specific engineering, vendor quotations, and utility coordination during the advanced design phase.

Net Energy Metering

Net Energy Metering (NEM) in California is a billing arrangement that allows residential and commercial customers who generate their own electricity, primarily through solar photovoltaic (PV) systems, to receive credit for the surplus energy they contribute to the grid. This system is designed to incentivize the use of renewable energy sources by offsetting the cost of electricity consumption with the energy produced by these installations.

Under NEM, when a solar system generates more electricity than is consumed, the excess energy is sent back to the utility grid, and the customer earns credits. These credits can then be used to offset the cost of energy drawn from the grid when the solar system isn't producing enough to meet the customer's demand, like during nighttime or cloudy days. The rules, rates, and credits under NEM can vary over time, with different iterations such as NEM 1, 2, and the latest NEM 3, each having specific regulations and compensation structures for solar energy production and exchange.

The transition from NEM 2 to NEM 3 in California, which was effective on April 14, 2023, introduced significant changes in the net metering policies for utility customers with photovoltaic (PV) systems. These changes impact

several aspects, particularly the economics of energy arbitrage between PV system owners and the utility. Here's a summary of the key changes:

1) **Reduction in Export Rates:** Under NEM 3, there's a substantial reduction in the rates for excess electricity exported onto the grid by solar systems. This rate has been reduced by approximately 75%, thereby lowering the overall savings for home solar systems and increasing the payback period. This change is a shift from the traditional one-to-one offset of net metering policies, where the price of a kWh of electricity pushed onto the grid was equal to the price of a kWh pulled off the grid.
2) **Implementation of Electrification Rates:** Customers enrolling in NEM 3 are required to use electrification rates instead of regular Time-of-Use (TOU) rates. These electrification rates feature higher on-peak charges and lower off-peak charges, along with a fixed charge of $15 per month. The peak rate period remains from 4 pm to 9 pm.
3) **Export Compensation Based on Avoided Cost Calculator (ACC):** Export compensation under NEM 3 is determined by California's ACC, with specific export rates for every combination of Month, Hour, and Weekday or Weekend. The export value is lowest in the middle of the day when solar energy is abundant on the grid and highest during peak summer demand periods. Notably, the export rates are significantly lower than retail rates during the hours when PV systems are most productive (10 am – 3 pm). To maintain the financial viability of solar PV systems, customers in PG&E and SCE service territories receive an adder on top of the ACC rate, ranging between 2.2 and 9 cents depending on location and customer class.
4) **Shift to a Cost Avoidance System:** NEM 3 introduces a cost avoidance system for exported electricity. This system pays customers the lowest amount a company can pay under the Public Utility Regulatory Policies Act of 1978 (PURPA), which is significantly less than the typical retail rate. This results in customers receiving, on average, 75% less for the electricity they sell back to the grid, with rates varying by month and by hour.
5) **Grandfathering NEM 2 under NEM 3:** Under the recent NEM 3 policy in California, existing customers with a photovoltaic (PV) system installed under NEM 2 can retain the benefits and terms of their NEM 2 agreement, a process known as "grandfathering." However, these customers are restricted from replacing or adding capacity to their PV systems if they wish to maintain their NEM 2 status, as any significant modifications would require transitioning to the terms of NEM 3.

The Net Energy Metering (NEM) 3.0 policy introduces transformative changes, particularly enhancing the value of utilizing Battery Energy Storage Systems (BESS) for owners of solar power systems. A significant aspect of NEM 3.0 is the reduction in compensation rates for surplus electricity fed back into the grid by solar systems, now down to 75%. This adjustment shifts the financial dynamics, making it less lucrative to export excess solar energy to the grid. Instead, storing this surplus energy in a BESS and utilizing it when energy costs are higher becomes a more financially savvy approach.

The utility of BESS extends beyond merely optimizing the use of solar energy. It offers several additional advantages, such as providing backup power during utility blackouts, mitigating charges associated with demand peaks, and enabling energy arbitrage. Energy arbitrage under this system allows for the charging of BESS not only with excess solar energy but also with cheaper grid energy during low-cost periods. This stored energy can then be used in lieu of more expensive grid power at peak times, effectively reducing reliance on utility-supplied energy. Consequently, NEM 3.0 not only promotes more efficient use of solar energy but also broadens the scope of BESS applications, contributing to a more versatile and resilient energy management strategy.

AECOM



Microgrid Feasibility Study
City of Beaumont

Site:
Albert A. Chatigny Senior Community Center
1310 Oak Valley Parkway, Beaumont, CA 92223

February 2026

Delivering a better world

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Executive Summary

This study appraises the viability and benefits of distributed energy resource implementation scenarios at the subject site. Four scenarios were developed and comparatively evaluated, with key metrics summarized below:

Case	Components	CAPEX ($)	Utility Savings (kWh)	Bill Savings ($)	Payback Period (years)	GHG Reduction ($MTCO_2e$/year)
1	PV	~$193k (net w/ ITC)	~43%	~$35k	~6	~47
2	PV + BESS	~$333k (ITC + SGIP)	~90%	~$73k	~5	~47
3	BESS	~$70k	–	–	–	–
0	Business-as-usual	–	–	–	–	–

Note: All values are approximate and based on feasibility-level assumptions.

- **Case 1: Photovoltaic (PV) array** – Introduces on-site generation capability and materially reduces energy and demand charges. However, it remains exposed to unfavorable export pricing under NEM 3 due to lack of storage.
- **Case 2: PV + battery energy storage system (BESS)** – PV array plus battery energy storage system (BESS). Enables load shifting and self-consumption of surplus solar energy, significantly increasing annual savings, accelerating capital recovery, and improving operational resilience.
- **Case 3: BESS only** – Provides limited resilience value but is largely redundant due to the presence of an existing 250 kVA standby generator already capable of supporting identified critical loads.
- **Case 0: Business-as usual** – Maintains current utility dependence with no additional economic, environmental, or resilience benefits.

Considering the analysis presented in this study, Case 2 (PV + BESS) is identified as the recommended scenario. Although it carries higher upfront capital cost than PV alone, Case 2 delivers substantially higher annual savings, the shortest payback period, and enhanced resilience benefits by minimizing grid reliance and exposure to time-of-use and export pricing under NEM 3.

Recommended Next Steps

1. Advance to a 30% design phase with detailed site and structural assessments
2. Procure vendor-specific quotations to refine cost estimates beyond what is provided in this study
3. Initiate permitting and interconnection applications with Southern California Edison under the current Net Energy Metering tariff (NEM 3.0)
4. Secure federal incentives, specifically the 30% Investment Tax Credit (direct pay), to lower upfront costs
5. Prepare procurement and construction planning, targeting installation within the next budget cycle.

The goal is that with these data-driven microgrid feasibility assessment findings, the City of Beaumont can make an informed decision regarding an appropriate resilience-improving investment at the subject site.

Background

Purpose

In recent years, especially within the past decade, the impacts of extreme heat and wildfires have been profound through the Inland Empire. Power service disruptions have been increasing in frequency and severity throughout Riverside County, affecting the availability of essential services and community resources.

In 2023, the Western Riverside Council of Governments (WRCOG) received an award (Grant Agreement OPR23145) from the Adaptation Planning Grant Program of the California Governor's Office of Land Use & Climate Innovation Integrated Climate Adaptation and Resilience Program. This program provides funding to help fill local, regional, and tribal planning needs, provides communities the resources to identify climate resilience priorities, and supports the development of a pipeline of climate-resilient infrastructure projects across the state.

As part of this grant-funded project, the Energy Resilience Plan 2.0, WRCOG commissioned microgrid feasibility studies for its member agencies. These studies serve to provide valuation of a potential microgrid at a community-essential facility, as designated by the member agency.

The site selected for the City of Beaumont is the Albert A. Chatigny Senior Community Center located at 1310 Oak Valley Parkway, Beaumont, CA 92223.

This study presents key insights and findings from the evaluation of distributed energy resource (DER) scenarios, including photovoltaic (PV) array and battery energy storage system (BESS) components, at the subject site. It includes analysis of the site's historic energy demand profile and appraises potential PV array and BESS sizing and siting scenarios accordingly. Notably, the study includes assessment of the generation and storage requirements to support the site's critical loads to enable resilience for a specified number of hours during power service disruptions.

Furthermore, this study outlines the financial implications of self-generation, including estimated cost savings, return on investment (ROI), and potential financing options for the project.

It is important to note that this study serves as a preliminary technical and financial assessment. Its purpose is to provide the City of Beaumont with the information to make an informed decision on whether to proceed to next phases of microgrid implementation before committing to detailed engineering design and further investment.

Adaptation Planning Grant Program

As communities in California experience more frequent, prolonged, and severe impacts from climate change, communities and governments at all scales are developing strategies and implementing actions to build a climate-resilient future. However, many jurisdictions, especially under-resourced communities in California, lack the capacity, tools, guidance, and resources to effectively prepare for climate impacts.

The Adaptation Planning Grant Program addresses this capacity gap by providing funding to help fill planning needs, providing communities with the resources to identify climate resilience priorities, and supporting the development of climate resilience projects across the state. The Adaptation Planning Grant Program enables communities to climate risk and adaptation considerations into planning activities and prepare for climate readiness and resilience in the long term.

The Adaptation Planning Grant is part of the Integrated Climate Adaptation and Resiliency Program (ICARP) housed within the Governor's Office of Land Use and Climate Innovation. ICARP advances statewide climate adaptation and resilience by coordinating investments, partnerships, and climate science to ensure people, natural systems, and the built environment are protected, prepared, and thrive in the face of climate change.

Through direct and equity-focused investments and resources, ICARP helps build climate adapted and equitable communities in California, with a focus on solutions that address the impacts of climate change and reduce greenhouse gas emissions. ICARP works to advance these priorities across all levels of government by developing

actionable science and research; providing guidance, tools, and technical assistance; and administering climate resilience-focused grant programs.

Learn more: https://lci.ca.gov/climate/icarp/

Modeling Methodology

This section defines the criteria for sizing the PV array and BESS system components, detailing general parameters, technical requirements, and expected performance criteria.

PV Modeling

1. **Data Inputs**
    - **Solar Resource**: Hourly or sub-hourly irradiance data (e.g., typical meteorological year or on-site measurements)
    - **Site-Specific Factors**: Tilt angle, azimuth, shading analysis, and available roof/ground space
2. **Simulation Approach**
    - Use of HelioScope software to estimate hourly PV production
3. **Sizing Criteria**
    - **Capacity Target**: The sizing criteria are based on 115% of the facility's current annual energy consumption. This approach aims to fully offset the facility's energy usage with the PV array while incorporating an additional 15% capacity to accommodate future demand growth. However, the final system capacity is constrained by the area designated as available by the client.
    - **Performance Ratio**: Evaluate Performance Ratio to ensure consistent system output
    - **Energy Production**: Hourly, daily, monthly, and annual PV generation forecasts
    - **Load Matching**: Amount of PV energy that directly offsets site load vs. excess exported to the grid

BESS Modeling

1. **Data Inputs**
    - **Load Profile**: Detailed electricity consumption and demand patterns
    - **PV Production Profile**: From the PV modeling results
    - **Energy Duration for Resilience**: Determine the critical loads that the BESS will support during islanding operations
2. **Operational Modes**
    - **Energy Shifting / Excess PV Storage**: Battery charges when PV output exceeds site demand, discharges when site demand is high.
    - **Resilience (Standalone BESS)**: Sized to support critical loads during outages
3. **Sizing Criteria**
    - **Capacity (kWh)**: Based on required autonomy (energy shifting, peak shaving, or resilience duration)
    - **Max Discharge/Charge Rate (kW)**: Aligned with site load peaks, PV generation surpluses, and emergency power needs
4. **Simulation Approach**
    - Hourly or sub-hourly dispatch modeling to maximize economic benefit (e.g., demand charge reductions or avoided peak rates)

- Incorporate battery round-trip efficiency, self-discharge, and operational constraints (e.g., partial charge strategies)

5. **Output**

   - **Discharge/Charge Profiles**: Hourly modeling of how the battery is utilized
   - **Cost Savings**: Reduction in energy and demand charges or avoided grid cost
   - **Backup Duration**: If sized for resilience, the total hours/days of critical load coverage

Assumptions

AECOM collected facility data through a request for information process. Energy consumption factors and facility characteristics were identified and integrated in analysis. AECOM used these combined datasets to confirm energy utility consumption baselines.

In performing the analysis, AECOM made the following assumptions:

- This report refers to the Albert A. Chatigny Senior Community Center located at 1310 Oak Valley Parkway, Beaumont, CA 92223.
- The monthly and annual electricity consumption is determined using load profile data in the client-provided file "CRC - SCE_Usage_8000098481_12-01-24_to_12-11-25.” This file contains 35,040 load profile data points, which are then consolidated into an 8760 load profile dataset.
- AECOM utilized the Levelized Cost of Energy (LCOE) for the installed cost per watt of PV installations and BESS, as sourced from the National Laboratory of the Rockies (NLR). This data was used to estimate the hypothetical cost of installing the PV array and BESS at the site, as detailed in this report. For an accurate cost estimation, it is necessary to obtain vendor quotes, which are subject to change due to market-dependent time windows. These quotations are typically conducted during the 60% design phase, at which point there is an understanding of the specific equipment ratings and brands to be used.
- This report evaluates the site’s existing electrical infrastructure using customer-provided data on the main breaker and bus capacity, as documented in the client-provided file “CRC Building Plans.” AECOM has assessed whether the existing electrical system can support the proposed PV array and BESS installation. However, as this is a feasibility study, an on-site assessment is required for a definitive determination. A site visit should be conducted during the advanced design phase, typically at the 30% design stage, to confirm site-specific conditions.
- AECOM has estimated the potential PV generation capacity based on the client-address available area, as However, a site assessment is required in later project phases, typically at the 30% design stage, to ensure that the site has the necessary infrastructure for PV array installation. This includes evaluating civil structures, load-bearing capacity, particularly for rooftop installations, and other critical conditions necessary for successful implementation.
- This report uses a regionalized estimate of general production (kWh) to calculate the amount of greenhouse gas emissions avoided through PV generation. The calculation is based on the U.S. EPA Emissions & Generation Resource Integrated Database (eGRID).
- This report clarifies that other charges such as connection fees, required service charges, and taxes remain unchanged. The analysis focuses solely on the bill components directly affected by the installation of PV and BESS under the NEM 3 framework.

AECOM utilized the following tools in conducting the analysis:

- AECOM Internal Tools: Proprietary tools developed by AECOM for analyzing energy patterns and evaluating system performance in simulated environments. These tools are designed to assess energy costs for applications such as peak shaving, energy trading, etc. in DER implementations.
- HelioScope: Web-based software tool used for the design and performance analysis of photovoltaic systems. It combines system layout design with energy simulation, allowing users to model rooftop, ground-mounted, and canopy PV installations. The software factors in module placement, tilt, azimuth, shading, and local weather data to provide accurate estimates of system capacity and expected energy generation.

Site Information

In terms of electrical infrastructure, the site is served by a utility-fed electrical system consisting of a meter-main section, automatic transfer switch (ATS), and a main distribution panel with an available fault current rating of 42 kAIC. Power is distributed to multiple feeder sections supplying distribution panels and transformers throughout the facility.

The system includes three distribution transformers: one 75 kVA 480/120-208 V, one 37.5 kVA 480/120-208 V, and one 25 kVA 480/120-240 V unit, feeding several subpanels rated between 100 A and 200 A. The facility is equipped with a **250 kVA standby generator** connected through the ATS to support designated emergency and standby loads. Copper conductors are used throughout the system, with feeder sizes up to 350 kcmil and calculated voltage drops generally below 1.5 percent. The system is properly grounded and designed in accordance with applicable NEC requirements.

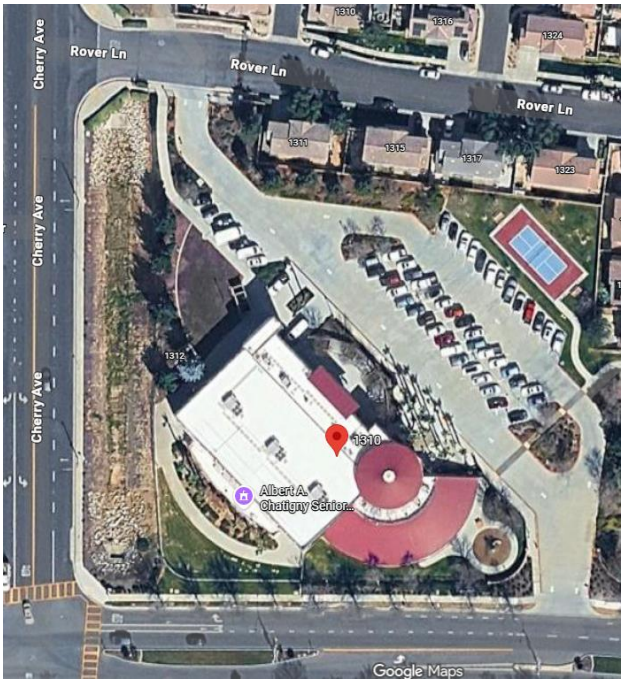


Figure 1. Site Location

Incentive Programs

AECOM has identified three key incentive programs that could benefit the subject site, focusing on renewable energy production and advanced energy storage systems.

The Investment Tax Credit (ITC) and Production Tax Credit (PTC) are federal incentives that reduce the cost of renewable energy projects. ITC offers a tax credit based on a percentage of upfront investment costs, while PTC provides a per-kilowatt-hour credit for electricity generated over time.

Production Tax Credit

Under this initiative, the project is eligible for a tax credit ranging from 0.3 cents to 1.5 cents per installed kWh. The specific value of the credit is determined by several factors, including the project's adherence to certain requirements such as complying with labor standards and using domestic materials.

The PTC program pays for each kilowatt-hour produced over a 10-year period, with government entities receiving the benefit as direct pay instead of a tax credit. For this project, with an estimated 241,040 kWh per year, the best case at 1.5¢/kWh would yield about $3,616 annually, totaling around $36,160 over 10 years.

Investment Tax Credit

The City can take advantage of either the ITC or the PTC, but both cannot be utilized simultaneously. Since construction has not yet commenced, selecting the ITC is the most advantageous option. Under this scenario, the project is limited to the base 30 percent credit because it does not meet any conditions for additional bonus allocations.

The ITC provides an extra 10 percent credit for projects located in federally designated low-income communities. However, according to the 2016–2020 census tract classification shown in Figure 3, the project site is located outside the eligible low-income area. As a result, the project does not qualify for the additional 10 percent bonus and remains capped at the standard 30 percent ITC.

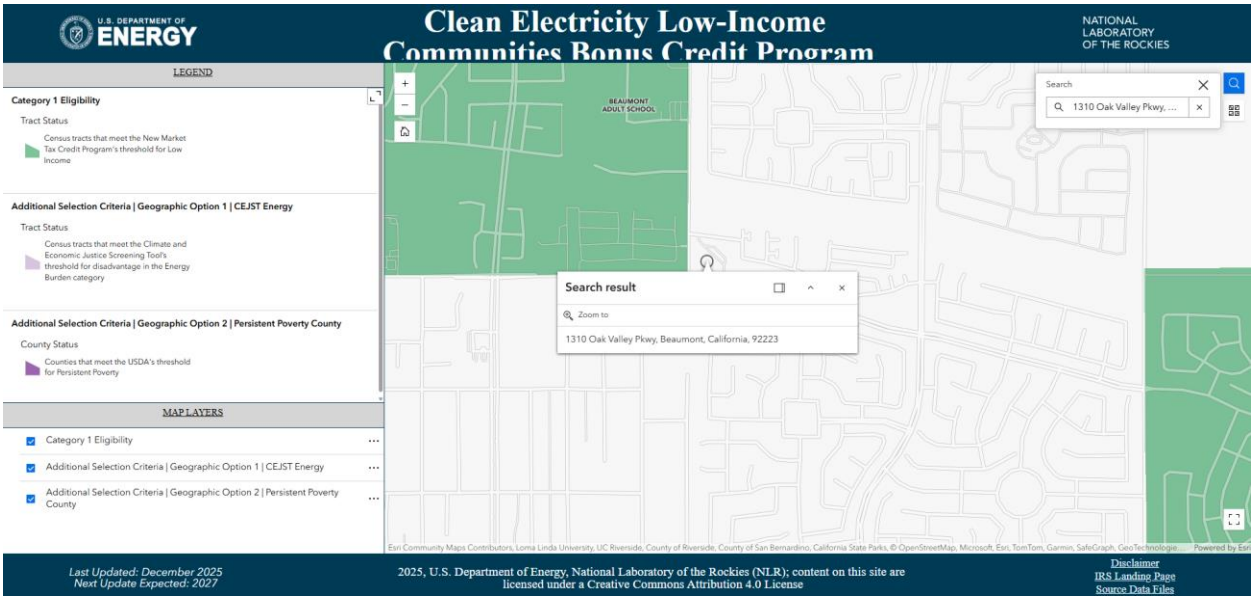


Figure 2. Clean Electricity Low-Income Communities Bonus Credit Program Map

NLR estimates capital expenditure (CAPEX) for commercial PV at $1.75–2.00/Wdc. For this study, a 138 kWdc PV system is projected. Based on these CAPEX values, total installation cost ranges from $241,500 to $276,000. With the standard 30 percent ITC, the direct-pay benefit for the City would fall between $72,450 and $82,800.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) is California's primary incentive designed to reduce the upfront cost of energy storage systems. The program has three levels

- **General Market:** For projects located outside Disadvantaged Communities (DAC). Typical incentive: $0.10/Wh.
- **Equity (DAC):** For projects located within a DAC. Incentive: $0.85/Wh.
- **Equity Resilience:** For critical facilities within a DAC and in PSPS or high fire-risk zones. Incentive: $1.00/Wh.

In Case 1, the project site is outside a DAC, so it only qualifies for the General Market level. Using an NLR-based cost of $450/kWh, a 400-kWh battery would cost approximately $180,000. With the General Market incentive of $0.10/Wh, the project would receive about $40,000, resulting in a net battery cost of roughly $140,000.

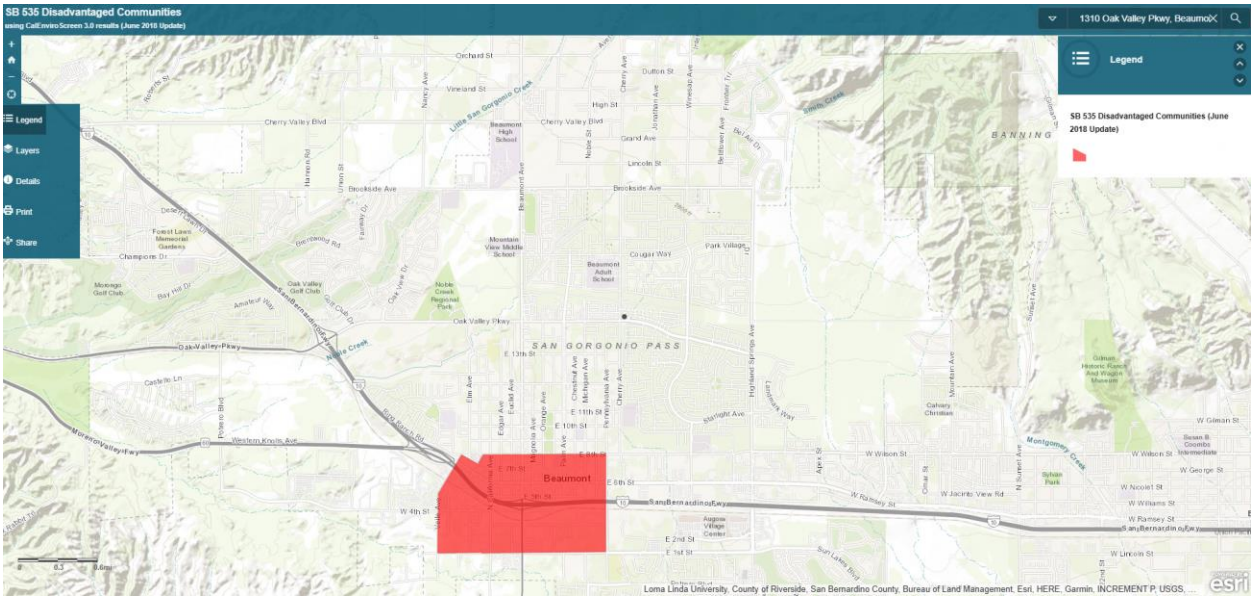


Figure 3. SB 535 Disadvantaged Communities Map

Scenarios & Analysis

Case 0: Current Situation (Baseline)

Tariff & Contract Type

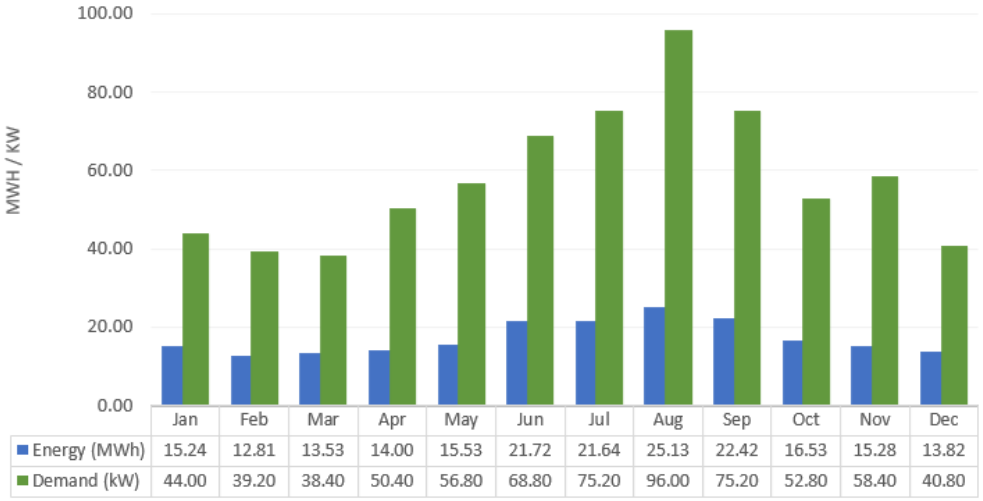
The site is currently served by Southern California Edison under the TOU-GS-2-D CPP tariff, which is designed for small to medium commercial customers. This rate structure separates costs into energy charges (based on kilowatt-hours consumed) and demand charges (based on the highest kilowatt demand registered during the billing cycle). In addition, prices vary by time-of-use periods—on-peak, mid-peak, and off-peak—so the timing of energy use significantly affects overall costs.

Being on this tariff means the site's operating expenses are directly tied not only to how much energy is consumed but also to when it is consumed and how high the peak demand reaches.

The tariff cost presents the costs as totals (delivery + bundle). The prices were used as the basis for this study. While they may fluctuate slightly month to month depending on market conditions, these variations are generally minor.

Monthly & Annual Energy Consumption and Demand

The facility currently consumes 207,649 kWh annually, with August being the highest month at about 25,130 kWh and February the lowest at about 12,810 kWh. In terms of demand, August records the peak at around 96 kW, while March is the lowest at about 38.4 kW. The following graph presents this historical data for the 2024–2025 period.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Energy (MWh)	15.24	12.81	13.53	14.00	15.53	21.72	21.64	25.13	22.42	16.53	15.28	13.82
Demand (kW)	44.00	39.20	38.40	50.40	56.80	68.80	75.20	96.00	75.20	52.80	58.40	40.80

Figure 4. Historic Site Energy Profile

Monthly & Annual Energy Costs

The site currently spends about $81,306 per year in energy and demand cost, with approximately $60,008 in energy costs and $30,570 in demand charges, based on tariff TOU-GS-2-D-CPP simulation. For this analysis, we are focusing only on energy and demand costs, as these are the components directly impacted by the installation of a PV system.

Case 1: PV Only

Installed Capacity & Location

The PV system for the site was sized to offset approximately 115% of current consumption, with the goal of fully offsetting present usage while reserving about 15% additional capacity for future growth. The placement areas for the PV installation were identified according to customer requirements. The system capacity is estimated at 138 kW direct current (DC), with an expected annual production of about 241,040 kWh.

Figure 6 presented the modeled energy production throughout the year, and Figure 7 identifies the designated PV installation areas on the site.

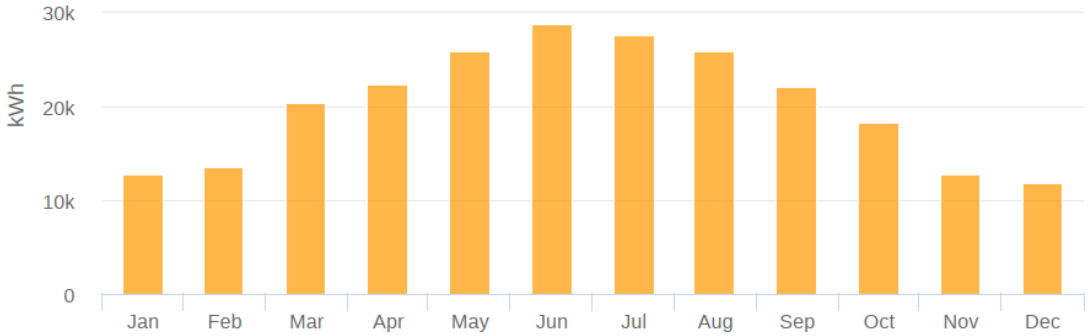


Figure 5. Modeled PV Production



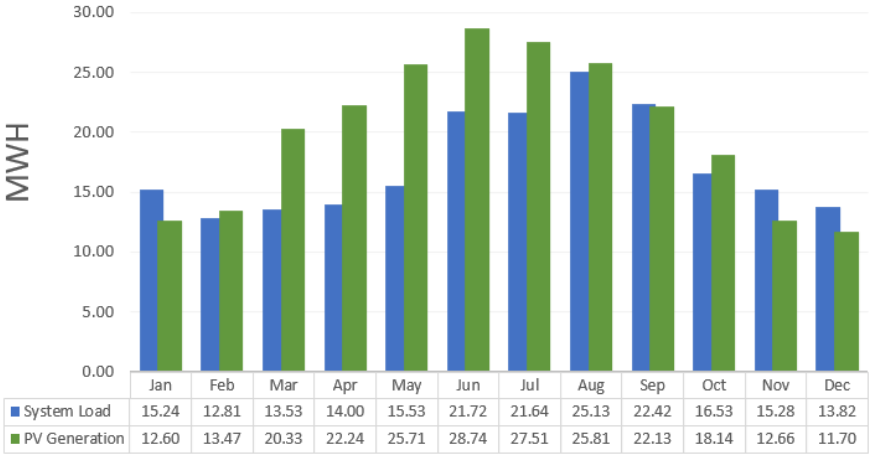
Figure 6. Modeled PV Installation Areas

Modeled PV Production

The modeled PV system is projected to generate an average of **20,087 kWh per month**, with an estimated **annual production of 241,040 kWh**.

This scenario does not include a BESS, so the excess energy produced need be exported to the utility, which requires entering a Net Energy Metering (NEM) contract with the utility service provider. Under the currently available NEM tariff, NEM 3.0, exported electricity is credited at dynamic rates that vary by month, hour of day, and weekday, ranging from as low as $0.01/kWh during midday hours to over $1.00/kWh during peak evening hours in high-demand months like August and September. This study has calculated projected benefits from this arrangement.

Figure 8 compares historic monthly energy consumption and modeled PV generation. Not all solar energy will be consumed on-site, as excess daytime production may exceed demand and be exported to the grid, while nighttime demand cannot be covered since there is no generation after sunset and no battery to store the excess in this scenario.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
System Load	15.24	12.81	13.53	14.00	15.53	21.72	21.64	25.13	22.42	16.53	15.28	13.82
PV Generation	12.60	13.47	20.33	22.24	25.71	28.74	27.51	25.81	22.13	18.14	12.66	11.70

Figure 7. Modeled PV Output vs. Site Demand

Capital Expenditures

Based on NLR benchmark CAPEX values for commercial rooftop solar, the estimated cost to install a 139 kW DC PV system in Riverside County, California falls in the range of $1.75 to $2.00 per watt DC. This translates to a total investment of **approximately $241,500 – 276,00 for the complete system**.

These figures include **typical equipment, installation, and soft costs**, reflecting average market conditions for commercial-scale projects. Actual costs may vary slightly depending on site-specific conditions such as roof structure, permitting, interconnection requirements, and labor. However, the NLR benchmarks provide a reliable basis for estimating the capital cost of a system of this size and type in the region.

Operating Expenses

According to NLR's 2024 benchmark data, the annual operations and maintenance (OPEX) cost for commercial rooftop PV systems is about $19 per kW-DC. For a 138 kW DC system, this translates to an estimated yearly **OPEX of roughly $1,600** covering routine maintenance, monitoring, and related operational expenses.

Economic Metrics

The analysis shows that installing a PV system at the site under NEM3 provides measurable financial benefits by offsetting both energy and demand charges. Without solar, the facility currently spends about $81,306 annually on utility costs. With the PV system in operation, the energy cost is reduced to approximately $33,029 per year, while the demand cost drops to about $17,546 per year. In addition, the system generates excess electricity during the day that cannot be fully consumed on-site. Under NEM3 rules, this exported energy represents an additional benefit of roughly $4,398 annually.

Taken together, these reductions and export credits bring the facility's total utility bill down to **$46,177 per year**, achieving an **overall savings of about 43%** compared to current expenses

Payback Period and Return on Investment

The financial analysis shows that without PV, the facility spends approximately $81,306 per year on utility costs. With a 138 kW DC PV system installed, the annual cost is reduced to about $46,177, resulting in yearly savings of roughly $35,129. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system is estimated at $276,000, but with the 30 percent ITC direct pay, the net investment is reduced to approximately $193,200. In addition, the system carries an annual OPEX of $2,622, which slightly offsets the yearly savings. Taking these factors into account, the project generates a net benefit of about $35,129 minus 2,622 per year after OPEX. This results in a simple payback period of approximately 6 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross Savings ($)	Net Savings after OPEX ($)	Cumulative Cash Flow ($)
1	35,129	32,507	-160,693
2	36,183	33,482	-127,211
3	37,268	34,487	-92,724
4	38,386	35,521	-57,203
5	39,538	36,587	-20,616
6	40,724	37,685	17,069
7	41,946	38,815	55,884
8	43,204	39,980	95,863
9	44,500	41,179	137,042
10	45,835	42,414	179,457
15	53,136	49,170	411,395
20	61,599	57,001	680,276

Table 1. Return on Investment w/ 3% Inflation: Case 1

Technical Feasibility

The facility distribution backbone operates at 480 V, 3-phase and supplies multiple downstream feeders including a 75 kVA transformer with a 480 V primary and 120/208 V secondary in a 3-phase, 4-wire configuration; the service equipment fault current rating is 42,000 AIC.

A 138 kW PV system interconnected at 480 V, 3-phase produces an inverter output current of 166 A (I = 138,000 W ÷ [1.732 × 480 V]). As a continuous source, the PV output circuit requires a minimum ampacity of 208 A (1.25 × 166 A), which drives a 225 A, 3-pole PV interconnection overcurrent device and output feeder rating.

NEC 705 bus loading compliance for a load-side backfeed interconnection requires explicit verification of the main distribution panel bus rating and the main overcurrent device rating and location. The allowable backfeed limit is defined by NEC 705 using the 120 percent rule where applicable ($I_{backfeed,max} = 1.20 \times I_{bus} - I_{main}$), and this calculation cannot be completed because the one-line does not state the main breaker rating or main bus ampere rating.

Interconnection shall be executed by either (1) providing the verified NEC 705 load-side backfeed capacity at the selected 480 V panelboard/switchboard location for a 225 A PV breaker, or (2) implementing a supply-side connection sized for a 225 A PV output circuit and coordinated with the service equipment rating and short-circuit requirements, or (3) upgrading the interconnection bus and main overcurrent device ratings to achieve a compliant backfeed margin for 208 A minimum PV source contribution.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 241,040 kWh per year. Using the U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:"

- Carbon dioxide (CO_2): 103,262 pounds (lbs) (46.84 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 103,647 lbs (47.01 metric tons) avoided annually
- Nitrogen oxides (NOx): 80.03 lbs (36.30 kg) avoided annually
- Sulfur dioxide (SO_2): 4.82 lbs (2.19 kg) avoided annually

Case 2: PV + BESS

System Components

This scenario assumes the same PV array described in Case 1 and a BESS sized for surplus PV production. The day with the highest energy surplus in our simulation occurred on May 18, during which the PV system produced 987.09 kWh, the site consumed 332.80 kWh, and the resulting surplus was 654.29 kWh. For size the BESS, we ran several iterations based on the available surplus energy and applied an algorithm that simulates the charge and discharge cycles of one year. This techno-financial analysis indicates that the optimal BESS capacity is approximately 400 kWh.

This simulation factor ensures that even under variations in production or demand, all possible excess solar energy generated during the day can be stored. The stored energy is then available for use at night or during periods when PV production does not fully cover the site's demand.

By doing so, most of the units of solar energy produced on-site are consumed daily by the facility, preventing as little as possible any export to the grid.

Modeled Energy Flows

By installing a 400 kWh battery, we ensure that all the energy generated on-site is consumed by the facility itself. The charge and discharge profile of the battery is designed so that any PV surplus during the day is immediately stored in the battery rather than exported to the grid. Later, if the site demand exceeds the PV generation while there is still energy stored in the battery, the deficit is supplied from the battery.

This operational strategy minimizes or even eliminates consumption from the utility, since the PV and battery combination is prioritized to cover the load at all times. On an annual basis, the system is expected to produce slightly more energy than the site requires, leaving a surplus of around 10%, but this excess is negligible in terms of the overall utility bill.

Capital Expenditures

According to NLR benchmark data, the capital expenditure (CAPEX) for a commercial-scale 138 kW DC rooftop PV system in Riverside, California is estimated at $193,200 under ITC incentive, based on installation costs of $1.75–2.00 per watt DC.

For storage, NLR's 2025 cost projections indicate a CAPEX of $450 per kWh for the high-cost scenario. Applying this benchmark to a commercial-scale 400 kWh battery system represents an investment of roughly 180,000 and under the SGIP program this amount can be fully covered, effectively funding 29% of the BESS system

Together, the combined CAPEX for the PV and BESS systems is estimated at 373,200 under ITC and SGIP representing the expected upfront investment for a commercial solar-plus-storage project of this size.

Operating Expenses

According to NLR benchmark data, the annual operations and maintenance (OPEX) cost for a commercial-scale 138 kW DC rooftop PV system is estimated at $2,622 USD.

NLR data indicates an operating cost of approximately $4 per kW-year. For a commercial-scale 400 kWh battery system, this results in an **annual OPEX of about $1,600**.

Together, the combined OPEX for the PV and BESS systems is approximately $4,222 per year, covering routine maintenance, monitoring, and system management.

Economic Metrics

The analysis shows that installing a commercial-scale PV system paired with a 400 kWh battery under NEM 3 provides strong financial advantages by allowing a substantial portion of the solar energy produced by the PV system to be consumed on-site.

In several cases PV production exceeds the facility's demand, and the surplus can be stored in the BESS for later use. However, without a battery system, the facility cannot absorb all of this excess energy, since any unused generation must be consumed the moment it is produced. This unused energy would otherwise need to be exported

to the utility grid, where under current NEM rules it would be compensated at only about 25 percent of the retail electricity rate. Given that time-of-use pricing makes stored energy far more valuable during high-cost periods, it becomes financially preferable to store surplus solar rather than sell it.

Without a BESS, exporting this excess would generate 4,398 but the facility would still face an annual utility cost of 46,177 By contrast, installing the BESS reduces grid reliance and allows the facility to consume nearly all of its solar production during higher-priced periods, resulting in a significantly lower annual utility bill of 7,780

To remain conservative, this analysis assumes that 10% of annual energy costs remain due to efficiency losses, imperfect alignment of PV output and site load, and seasonal variability.

It is important to note that other charges—such as connection fees, requisite charges, and taxes—remain unaffected. This analysis focuses only on those bill components directly impacted by the installation of PV and BESS under the NEM 3 framework.

Payback Period and Return on Investment

The financial analysis shows that without PV + BESS, the facility spends approximately $81,306 per year on utility costs. With a 138 kW DC PV system and 400 kWh BESS system installed, the annual cost is reduced to about $7,780 resulting in yearly savings of roughly $73,526. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system under ITC and SGIP incentives is estimated at $333,200. In addition, the system carries an annual OPEX of $4,222 Taking these factors into account, the combined system generates a net benefit of about 69,304 per year after OPEX. This results in a simple payback period of approximately 5 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross-Savings ($)	Net-Savings after OPEX ($)	Cumulative Cash Flow ($)
1	73,526	69,304	-263,896
2	75,732	71,383	-192,513
3	78,004	73,524	-118,989
4	80,344	75,730	-43,258
5	82,754	78,002	34,744
6	85,237	80,342	115,086
7	87,794	82,752	197,838
8	90,428	85,235	283,073
9	93,140	87,792	370,866
10	95,935	90,426	461,291
15	111,215	104,828	955,777
20	128,928	121,525	1,529,021

Table 2. Return on Investment w/ 3% Inflation: Case 2

Technical Feasibility

The existing electrical system consists of a utility service feeding a meter-main and an automatic transfer switch (ATS) serving a main distribution panel.

The ATS is arranged to accept standby power from an on-site 250 kVA generator, with downstream distribution through the main distribution panel and multiple feeder breakers.

The main distribution panel supplies multiple 3-phase feeders, including a 100 A 3-pole feeder and several 80 A, 60 A, and 30 A 3-pole feeders that serve step-down transformers and downstream panels.

The distribution includes a 75 kVA transformer (480 to 208/120 V, 3-phase, 4-wire) feeding two 200 A panels, a 37.5 kVA transformer (480 to 120/208 V, 3-phase, 4-wire), and a 25 kVA transformer (480 to 120/240 V, 1-phase, 3-wire), indicating a 480 V distribution backbone with multiple lower-voltage load centers.

Interconnection of the additional 138 kW AC PV requires a dedicated 3-phase interconnection point on the 480 V distribution, with a PV output current of approximately 166 A at 480 V. Provide a PV backfeed breaker and conductors sized for this continuous output, including an external visible-open PV AC disconnect and required labeling at the service and distribution equipment.

The 400 kWh BESS requires a dedicated interconnection breaker and disconnect on the 480 V distribution and a protection and control review to confirm compatibility with the ATS and generator source. The BESS must be arranged to prevent any unintended backfeed into the ATS normal or emergency sources and to maintain proper source interlocking and coordination with existing overcurrent protective devices.

Because the main distribution panel presently distributes power through multiple existing feeders and is tied to an ATS and generator, the PV and BESS interconnection must include a full coordination and settings review, confirmation of available breaker space/capacity, and any required upgrades to accommodate the added backfeed sources, including breaker additions or replacement of distribution equipment if adequate provisions are not available.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 241,040 kWh per year. Using the U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:"

- Carbon dioxide (CO_2): 103,262 lbs (46.84 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 103,647 lbs (47.01 metric tons) avoided annually
- Nitrogen oxides (NO_x): 80.03 lbs (36.30 kg) avoided annually
- Sulfur dioxide (SO_2): 4.82 lbs (2.19 kg) avoided annually

CASE 3: BESS Only

Critical Load Identification

Based on the facility classification as a community center, only systems mandated by code for life safety and legally required standby power are considered critical. In accordance with NEC 700 and NFPA 72, emergency loads are limited to egress lighting and fire alarm systems. NEC 701 and NFPA 110 allow inclusion of legally required standby systems such as minimal communications, security, and access control where provided through the emergency distribution path visible at the ATS. From the one-line configuration and typical community center requirements, the critical load is estimated at 50 kW, representing approximately 25 percent of the total connected load.

Required Backup Duration

While there is no state law requiring community centers to be equipped with generators, the City's own Safety General Plan aims to provide redundant backup systems (generators, solar, or battery) for buildings designated as emergency shelters.

Battery Capacity & Infrastructure

The battery energy storage system is sized directly from the emergency load and required duration. A critical load of 50 kW sustained for 4 hours results in an energy requirement of 200 kWh, with a corresponding power rating of 50.0 kW. The BESS would be required to interconnect on the emergency side of the ATS to ensure isolation from normal loads. Adequate emergency bus capacity, dedicated breakers, and protected feeders are required to route power exclusively to emergency circuits identified in the distribution panel.

Capital Expenditures

Using cost benchmarks published by the National Laboratory of the Rockies (NLR), the estimated capital cost (CAPEX) for a 200 kWh / 50 kW battery energy storage system is approximately $70,000. This figure includes the battery cabinets, inverter/PCS, microgrid controller with ATS, installation, protections, and engineering.

Operating Expenses

The expected operating cost (OPEX) is about $800 per year, also based on NLR reference values. This covers preventive maintenance, monitoring software, and NFPA 110 testing requirements. Battery replacement is typically required after 10–12 years of service.

Return on Investment & Qualitative Benefits

While a conventional financial return ROI cannot be directly applied to this case, the value of a BESS for a fire station is usually framed in terms of resilience, reliability, and compliance. Such systems are designed to ensure uninterrupted operation of life-safety and mission-critical equipment, including fire alarms, communications, lighting, and fuel dispensing, during extended utility outages. The benefits include maintaining service continuity, safeguarding firefighter readiness, and protecting the surrounding community. Compliance with NFPA 110, NFPA 70, and NFPA 72 also reduces liability exposure and ensures that the facility meets recognized safety standards.

However, for this particular fire station, the installation of a battery energy storage system does not present a compelling case. The facility already operates with a 125 kW emergency generator, which is more than sufficient to sustain the identified critical load of approximately 7.26 kW. Given this existing capacity, the addition of a 60 kWh / 20 kW BESS as a resilience measure would provide little to no incremental benefit relative to cost. The generator fully covers the resilience requirement, and therefore the justification for a BESS here would not be technical necessity

Technical Considerations

Integration of the BESS requires confirmation of available emergency bus capacity and compliance with the 120 percent load-side interconnection rule where applicable. Breaker sizing and feeder routing must preserve separation between normal and emergency circuits through the ATS. A short-circuit study, transfer-sequence verification, and coordination review are required to validate compatibility with existing protective devices. Battery system deployment must also address listing requirements and thermal safety considerations consistent with UL 9540A testing.

Decision Matrix and Scenario Comparison

In order to determine the most appropriate scenario for the site, four scenarios were developed and analyzed: business as usual (Case 0), installing a PV system only (Case 1), installing PV with a BESS (Case 2), and installing a BESS only (Case 3). Each case was evaluated in terms of resilience value, capital and operating expenditures, energy savings, payback period, and technical feasibility. The decision matrix summarizes the comparative performance of these options.

Criteria	Case 0: Baseline	Case 1: PV Only	Case 2: PV + BESS	Case 3: BESS Only
Resilience Benefit	None	Limited (daytime only)	Moderate (self-consumption, some coverage)	High (but redundant due to existing 125 kW generator)
CAPEX ($)	0	~$193k (net of 30% ITC)	~$333k (PV + BESS under ITC and SGIP)	~$70k (200 kWh / 50 kW system)
OPEX ($/yr)	Current $24k	~$988	~$1,988	~$2,000
Annual Utility Bill ($)	~$81,306	~$81,306	~$7,780	~$81,306 (no reduction)
Annual Savings ($)	–	~$35,129	~$73,526	Minimal (non-financial)
Payback Period	–	~6 years	~5 years	No ROI
GHG Reduction	None	~47 $MTCO_2e$ avoided annually	Same as Case 1	None
Technical Feasibility	Already in place	Requires breaker adjustment	Requires breaker + storage integration	Technically feasible but unnecessary

Table 3. Scenario Comparison

Conclusion

Based on the comparative technical and financial analysis, **Case 2 (PV + BESS)** is recommended as the preferred scenario for the site. While Case 1 (PV only) provides meaningful reductions in utility costs, the addition of battery storage in Case 2 significantly accelerates capital recovery and delivers materially higher long term benefits. The PV + BESS configuration maximizes on site consumption of solar generation under the NEM 3 framework, sharply reducing exposure to unfavorable export credits and time of use pricing, while also improving operational resilience.

The analysis demonstrates that Case 2 achieves the highest annual savings and the shortest simple payback period, approximately 5 years, compared to roughly 6 years for PV only. This improved performance is driven by the ability to store surplus daytime PV generation and discharge it during high cost evening periods, thereby minimizing both energy and demand charges. In addition, Case 2 reduces the annual utility bill to a near minimum residual level, providing strong protection against future rate escalation.

It is important to note that this study was performed assuming the site remains on the TOU-GS-2-D CPP tariff. The CPP structure materially enhances the value of storage by amplifying price differentials during critical peak events, which the BESS can directly mitigate. As part of the next phase, it is recommended to confirm tariff eligibility and validate that the site can remain on or be transferred to TOU-GS-2-D CPP while enrolling in NEM 3. If CPP participation is not feasible, an alternative such as TOU-GS-2-E should be evaluated. Although TOU-GS-2-E does not include CPP benefits, it is well suited for distributed energy resources and microgrid configurations and may still support favorable economics for the PV + BESS system. A targeted tariff sensitivity analysis is recommended to confirm the optimal rate structure.

While Case 3 (BESS only) provides resilience value, it does not offer a compelling economic justification due to the presence of an existing 250 kVA standby generator that already satisfies critical load requirements. Case 2, by contrast, complements the existing generator by reducing fuel reliance, improving operational efficiency during normal conditions, and delivering both financial and environmental value.

Summary of Strategy & Benefits

The selected strategy focuses on deploying a rooftop PV system sized to approximately 115 percent of the facility's annual energy consumption, paired with a 400 kWh battery energy storage system optimized for daily PV surplus capture and time shifting. This approach achieves the following benefits:

- **Resilience:** Enhances operational resilience by enabling load support through stored solar energy and reducing reliance on the utility during peak and outage conditions.
- **Economic Savings**: Reduces annual utility costs from approximately $81,306 to about $7,780 under the assumed tariff, yielding annual savings of roughly $73,526.
- **Financial Performance:** Delivers the fastest capital recovery among all cases, with a simple payback of approximately 5 years and strong long term cash flow under modest energy price inflation.
- **Environmental Impact:** Offsets approximately 47 metric tons of CO2e emissions annually through on site renewable generation.
- **Tariff Optimization:** Maximizes value under TOU-GS-2-D CPP and NEM 3 by minimizing low value exports and prioritizing self-consumption, with flexibility to evaluate TOU-GS-2-E if required.
- **Technical Viability**: Integrates with the existing 480 V distribution system and standby generator, requiring standard interconnection, protection, and coordination upgrades without major infrastructure replacement.

Next Steps

To advance the project, the following steps are recommended:

1. **Detailed Design & Site Assessment:** Conduct a 30% design phase evaluation, including structural assessment of the roof, electrical interconnection details, and shading analysis
2. **Vendor Quotations:** Obtain updated vendor quotes for PV system equipment, installation, and interconnection to refine cost estimates beyond NLR benchmarks
3. **Permitting & Interconnection:** Coordinate with Southern California Edison (SCE) to complete the interconnection study and ensure compliance with NEM 3 tariff rules
4. **Finalize Incentive Applications:** Submit applications for the 30% ITC (direct pay) to secure federal funding and reduce upfront capital cost
5. **Procurement & Installation:** Issue RFPs for procurement and construction, selecting qualified contractors with experience in municipal PV installations
6. **Commissioning & Monitoring:** Upon installation, perform commissioning tests, integrate the system with monitoring platforms, and establish an operations and maintenance (O&M) plan to ensure reliable long-term performance

Appendix

Incentive Programs

This section outlines how the incentive programs function and provides relevant information about them. Specific application of these programs to presented scenarios is explored in previous sections.

Inflation Reduction Act

The Inflation Reduction Act of 2022 stands as a significant piece of legislation designed to strengthen the United States' commitment to fighting climate change by making considerable investments in renewable energy. A key feature of the Inflation Reduction Act is its financial incentives, namely the Investment Tax Credit (ITC) and the Production Tax Credit (PTC), which aim to accelerate the adoption of renewable energy technologies.

The ITC allows for a significant tax credit for investments in renewable energy technologies, including solar panels and wind turbines, directly reducing the upfront cost of these systems. This makes renewable projects more financially viable and attractive to investors and consumers alike. On the other hand, the PTC provides a per-kilowatt-hour tax relief for the production of energy from renewable sources, incentivizing the operation and expansion of renewable energy facilities.

Notably, Inflation Reduction Act programs have been subject to change in recent legislation. Presented here are active opportunities as of the time of the report.

Production Tax Credit

The Production Tax Credit (PTC) within the framework of the Inflation Reduction Act offers considerable financial incentives for renewable energy projects, primarily designed to decrease the federal income tax liability based on the electricity produced per kilowatt-hour.

The PTC directly reduces the federal income tax for taxable entities. Furthermore, for non-taxable entities such as local governments, educational institutions, or nonprofit organizations, the PTC allows these credits to be monetized, facilitating their involvement in renewable energy initiatives. This provision is applicable for projects that become operational between January 1, 2023, and December 31, 2032, providing a broad window for planning and implementation.

Projects located in designated low-income energy communities receive further incentives. The PTC is structured to be claimable annually for a decade from the start date of operations of the qualifying renewable system, providing long-term financial support. This current structure of the PTC is set to continue through the end of 2024. Starting from January 1, 2025, the credit system will transition to a technology-neutral format, broadening the scope to include a wider array of technologies and fostering a more inclusive approach to renewable energy incentives.

As of the date of this report, the program is still active but solar projects must have “begun construction” by July 4, 2026.

The City project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

Investment Tax Credit

The Investment Tax Credit (ITC) established under the Inflation Reduction Act offers a powerful incentive for deploying renewable energy technologies by providing a reduction in federal tax liability. This reduction is calculated as a percentage of the capital investment made in eligible energy systems. Taxpayers can apply the ITC to their federal income tax for the year the technology is installed, significantly decreasing their tax burden.

Starting January 1, 2023, special provisions enable tax-exempt entities such as local governments and nonprofits to receive direct payments equivalent to the value of the credit. This arrangement improves the liquidity and financial feasibility of renewable projects for these organizations. The scope of eligible technologies under the ITC is broad, encompassing solar panels, wind turbines, fuel cells, and other renewable energy systems.

As of 2025, the Investment Tax Credit (ITC) for solar projects is set at 30% of the eligible costs, encompassing both the equipment and installation expenses. This rate is scheduled to decrease to 26% in 2033 and further to 22% in 2034. Systems rated under 1 megawatt (MW) qualify for the full 30% without having to comply with additional requirements; larger systems will only receive the full amount if they meet specific labor requirements. These include paying prevailing wages to workers during construction and using apprentices to perform a portion of the total construction hours (15% after 2023). Bonus credits are available based on site location, e.g., low-income communities.

The ITC is set to continue delivering these benefits at its current rate until 2032, contingent upon meeting the specific project criteria laid out in the act. Looking ahead, post-2024, the ITC will transition to a technology-neutral system, which will be applicable to all zero-emissions technologies, reflecting a shift towards a more inclusive and adaptable approach to supporting renewable energy development.

HHZP project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

As of the date of this report, the program is still active but critical deadlines for project eligibility and complete operability are quickly approaching in 2026 and 2027, respectively.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) offers financial incentives to non-residential customers of utility Company to encourage the adoption of energy storage systems. These systems help businesses prepare for power outages that may occur due to weather, emergencies, or other unforeseen events. The SGIP funding is authorized through 2024, with incentives structured to decrease over time as funding milestones are reached or as more participants enter the program.

Non-residential customers have access to three types of SGIP rebates: General Market, Equity, and Equity Resilience. Furthermore, SGIP incentives are significantly higher for vulnerable or disadvantaged communities through the Equity and Equity Resilience categories.

Incentives are typically paid upfront for residential systems upon project completion and site verification, while nonresidential systems may receive half upfront with the balance paid based on the system's performance over time. Eligibility for SGIP incentives extends to residential, commercial, industrial, agricultural, and municipal customers of specific utilities including Pacific Gas & Electric, Southern California Edison, SoCalGas, San Diego Gas & Electric, and those managed by the Center for Sustainable Energy.

To be eligible for this rebate, a facility must satisfy two conditions: firstly, it must fall under the category of a government agency, educational institution, non-profit organization, or small business. Secondly, it must fulfill at least one of the following requirements: be located in a Disadvantaged Community (DAC), be situated in a census tract where the Median Household Income of the Statewide Median Income or be situated in California Indian Country.

On the other hand, the equity resilience rebate offers a rate, covering a percentage of the cost of an average energy storage system. To qualify for this rebate, a facility must meet certain requirements. Firstly, it must have experienced two or more utility Public Safety Power Shut-offs (PSPS), or it should be located in a Tier 2 or 3 High Fire Threat District (HFTD) and serve customers in DACs or Low Income Communities. Secondly, it must fulfill at least one of the following additional criteria:

- Be a police station, fire station, emergency response provider, emergency operations center, 911 call center, medical facility, private and public natural gas, electric, water, wastewater, or flood facility, jail or prison, utility-designated PSPS assistance center, cooling center, homeless shelter.
- Be a grocery store, supermarket, or corner store with less than $15 million in annual gross receipts.

- Be an Independent Living Center or a Food Bank.

Modeling Assumptions

The modeling conducted for this feasibility study was based on standard industry benchmarks, available site data, and conservative assumptions to ensure realistic projections. The following key assumptions were applied:

1. **Energy Consumption Baseline** – Historical hourly load data (8,760 points) from the facility was consolidated to represent a typical annual profile. This served as the reference for sizing PV and BESS systems.
2. **PV System Costs** – Capital expenditure (CAPEX) and operations and maintenance (OPEX) values were derived from the National Laboratory of the Rockies (NLR) 2024–2025 benchmarks for commercial rooftop systems. PV CAPEX was assumed at $1.75–$2.00/Wdc, with OPEX at ~$19/kW-year.
3. **BESS Costs** – Battery energy storage CAPEX was modeled using NLR 2025 benchmarks at ~$350/kWh. OPEX was assumed at ~$40/kW-year, covering maintenance, monitoring, and lifecycle management.
4. **ITC Incentives** – A 30% Investment Tax Credit (direct pay) was assumed, reducing upfront project cost. No additional low-income or disadvantaged community adders were included since the site does not qualify.
5. **Performance Parameters** –
    - PV generation modeled with HelioScope using site tilt, azimuth, and shading factors.
    - Battery modeled with 90% round-trip efficiency and daily cycling where applicable.
    - Energy inflation rate of 3% annually applied to utility costs.
6. **Utility Tariff** – The analysis used the most recent Southern California Edison tariff, **TOU-GS-2 Option D**, as published in the file *ELECTRIC_SCHEDULES_TOU-GS-2_2025*. It was assumed under the current **NEM 3** framework. Exported PV energy was valued at ~25% of retail rate. Since tariff structures and prices are subject to future changes, the financial outcomes presented here should be viewed as indicative estimates rather than fixed projections.
7. **Infrastructure** – Electrical interconnection feasibility was preliminarily evaluated using customer-provided single-line diagrams. Minor breaker adjustment (600 A to 500 A) was assumed to comply with NEC 705.12 120% busbar rule for PV backfeed.
8. **Environmental Impact** – Greenhouse gas (GHG) reduction estimates were calculated using EPA eGRID emission factors for the CAMX subregion, applied to modeled PV generation.

Disclaimer: These figures are rough estimates intended for feasibility-level evaluation. If more precise values are required, additional detail must be developed through site-specific engineering, vendor quotations, and utility coordination during the advanced design phase.

Net Energy Metering

Net Energy Metering (NEM) in California is a billing arrangement that allows residential and commercial customers who generate their own electricity, primarily through solar photovoltaic (PV) systems, to receive credit for the surplus energy they contribute to the grid. This system is designed to incentivize the use of renewable energy sources by offsetting the cost of electricity consumption with the energy produced by these installations.

Under NEM, when a solar system generates more electricity than is consumed, the excess energy is sent back to the utility grid, and the customer earns credits. These credits can then be used to offset the cost of energy drawn from the grid when the solar system is not producing enough to meet the customer's demand, like during nighttime or cloudy days. The rules, rates, and credits under NEM can vary over time, with different iterations such as NEM 1, 2, and the latest NEM 3, each having specific regulations and compensation structures for solar energy production and exchange.

The transition from NEM 2 to NEM 3 in California, which was effective on April 14, 2023, introduced significant changes in the net metering policies for utility customers with photovoltaic (PV) systems. These changes impact

several aspects, particularly the economics of energy arbitrage between PV system owners and the utility. Here is a summary of the key changes:

1) **Reduction in Export Rates:** Under NEM 3, there is a substantial reduction in the rates for excess electricity exported onto the grid by solar systems. This rate has been reduced by approximately 75%, thereby lowering the overall savings for home solar systems and increasing the payback period. This change is a shift from the traditional one-to-one offset of net metering policies, where the price of a kWh of electricity pushed onto the grid was equal to the price of a kWh pulled off the grid.
2) **Implementation of Electrification Rates:** Customers enrolling in NEM 3 are required to use electrification rates instead of regular Time-of-Use (TOU) rates. These electrification rates feature higher on-peak charges and lower off-peak charges, along with a fixed charge of $15 per month. The peak rate period remains from 4 pm to 9 pm.
3) **Export Compensation Based on Avoided Cost Calculator (ACC):** Export compensation under NEM 3 is determined by California's ACC, with specific export rates for every combination of Month, Hour, and Weekday or Weekend. The export value is lowest in the middle of the day when solar energy is abundant on the grid and highest during peak summer demand periods. Notably, the export rates are significantly lower than retail rates during the hours when PV systems are most productive (10 am – 3 pm). To maintain the financial viability of solar PV systems, customers in PG&E and SCE service territories receive an adder on top of the ACC rate, ranging between 2.2 and 9 cents depending on location and customer class.
4) **Shift to a Cost Avoidance System:** NEM 3 introduces a cost avoidance system for exported electricity. This system pays customers the lowest amount a company can pay under the Public Utility Regulatory Policies Act of 1978 (PURPA), which is significantly less than the typical retail rate. This results in customers receiving, on average, 75% less for the electricity they sell back to the grid, with rates varying by month and by hour.
5) **Grandfathering NEM 2 under NEM 3:** Under the recent NEM 3 policy in California, existing customers with a photovoltaic (PV) system installed under NEM 2 can retain the benefits and terms of their NEM 2 agreement, a process known as "grandfathering." However, these customers are restricted from replacing or adding capacity to their PV systems if they wish to maintain their NEM 2 status, as any significant modifications would require transitioning to the terms of NEM 3.

The Net Energy Metering (NEM) 3.0 policy introduces transformative changes, particularly enhancing the value of utilizing Battery Energy Storage Systems (BESS) for owners of solar power systems. A significant aspect of NEM 3.0 is the reduction in compensation rates for surplus electricity fed back into the grid by solar systems, now down to 75%. This adjustment shifts the financial dynamics, making it less lucrative to export excess solar energy to the grid. Instead, storing this surplus energy in a BESS and utilizing it when energy costs are higher becomes a more financially savvy approach.

The utility of BESS extends beyond merely optimizing the use of solar energy. It offers several additional advantages, such as providing backup power during utility blackouts, mitigating charges associated with demand peaks, and enabling energy arbitrage. Energy arbitrage under this system allows for the charging of BESS not only with excess solar energy but also with cheaper grid energy during low-cost periods. This stored energy can then be used in lieu of more expensive grid power at peak times, effectively reducing reliance on utility-supplied energy. Consequently, NEM 3.0 not only promotes more efficient use of solar energy but also broadens the scope of BESS applications, contributing to a more versatile and resilient energy management strategy.

AECOM



Microgrid Feasibility Study
City of Beaumont

Site:
Fire Station 106 + Mesa Lift Station

February 2026

Delivering a better world

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Executive Summary

This study appraises the viability and benefits of distributed energy resource implementation scenarios at the subject sites. Four scenarios were developed and compared, with key performance metrics summarized below.

Case	Components	CAPEX ($)	Utility Savings ($/year)	Payback Period (years)	GHG Reduction ($MTCO_2e$/year)
1	PV	~$170k (net w/ ITC)	~$37k	~5	~41
2	PV + BESS	~$222k (net w/ ITC + SGIP)	~$48k	~5	~41
3	BESS	~$245k	Minimal	–	–
0	Business-as-usual	–	–	–	–

Note: All values are approximate and based on feasibility-level assumptions.

Scenario Overview

- **Case 1: Photovoltaic (PV) array** – Introduces on-site renewable generation and delivers meaningful utility cost savings with relatively low system complexity.
- **Case 2: PV + battery energy storage system (BESS)** – Increases on-site solar utilization, reduces low-value exports under NEM 3, and provides additional operational flexibility and resilience at a competitive payback.
- **Case 3:** BESS only – Provides additional backup capability and is largely redundant given the presence of existing standby diesel generators at both sites.
- **Case 0:** Maintains full dependence on the utility grid with no additional economic or resilience benefits.

Considering the comparative analysis presented in this study, **Case 2 (PV + BESS)** is identified as the recommended scenario. While Case 1 provides solid economic benefits, Case 2 delivers higher annual savings by enabling time-shifting of excess solar energy to higher-cost periods, resulting in the lowest annual utility cost among all evaluated scenarios. Although the inclusion of a BESS increases upfront capital cost and system complexity, these impacts are mitigated through the availability of the federal Investment Tax Credit and California's Self-Generation Incentive Program. Case 3 was not selected due to the existing standby generation assets, which already satisfy identified resilience requirements.

This study also appraised the feasibility of operating both Fire Station 106 and Mesa Lift Station as a single, customer-owned municipal microgrid behind one point of interconnection and one utility meter. Under California's regulatory framework, this configuration is permissible provided that all generation and loads are owned by the same legal entity and no sale or resale of electricity occurs. Electrical interconnection of the two parcels would require customer-owned infrastructure, utility approval, and additional engineering studies; however, the cost of this inter-site electrical infrastructure is not included in this feasibility assessment and would require further field investigation.

Recommended next steps include:

1. Advance to a 30% design phase to validate site conditions, structural capacity, and electrical integration requirements.
2. Perform field investigations and routing studies to evaluate the electrical interconnection between the two sites.
3. Obtain vendor-specific quotations for PV, BESS, and balance-of-system components to refine capital cost estimates.
4. Initiate permitting and interconnection coordination with Southern California Edison under the applicable DER framework.
5. Secure applicable incentives, including the 30% Investment Tax Credit (direct pay) and SGIP funding.
6. Develop procurement and construction planning aligned with the City's capital improvement and budget cycles.

These findings provide the City of Beaumont with a data-driven basis to proceed with a cost-effective, resilient, and regulation-compliant microgrid strategy that reduces long-term energy costs while increasing operational flexibility and sustainability.

Background

Purpose

In recent years, especially within the past decade, the impacts of extreme heat and wildfires have been profound through the Inland Empire. Power service disruptions have been increasing in frequency and severity throughout Riverside County, affecting the availability of essential services and community resources.

In 2023, the Western Riverside Council of Governments (WRCOG) received an award (Grant Agreement OPR23145) from the Adaptation Planning Grant Program of the California Governor's Office of Land Use & Climate Innovation Integrated Climate Adaptation and Resilience Program. This program provides funding to help fill local, regional, and tribal planning needs, provides communities the resources to identify climate resilience priorities, and supports the development of a pipeline of climate-resilient infrastructure projects across the state.

As part of this grant-funded project, the Energy Resilience Plan 2.0, WRCOG commissioned microgrid feasibility studies for its member agencies. These studies serve to provide valuation of a potential microgrid at a community-essential facility, as designated by the member agency.

The City of Beaumont selected a microgrid comprising both Fire Station 106 (2000 Western Knolls Avenue, Beaumont, CA 92223) and Mesa Lift Station (12940 Potrero Boulevard, Beaumont, CA 92223) to be the subject of this feasibility assessment.

This study presents key insights and findings from the evaluation of distributed energy resource (DER) scenarios, including photovoltaic (PV) array and battery energy storage system (BESS) components, at the subject site. It includes analysis of the site's historic energy demand profile and appraises potential PV array and BESS sizing and siting scenarios accordingly. Notably, the study includes assessment of the generation and storage requirements to support the site's critical loads to enable resilience for a specified number of hours during power service disruptions.

Furthermore, this study outlines the financial implications of self-generation, including estimated cost savings, return on investment (ROI), and potential financing options for the project.

It is important to note that this study serves as a preliminary technical and financial assessment. Its purpose is to provide the City of Beaumont with the information to make an informed decision on whether to proceed to next phases of microgrid implementation before committing to detailed engineering design and further investment.

As communities in California experience more frequent, prolonged, and severe impacts from climate change, communities and governments at all scales are developing strategies and implementing actions to build a climate-resilient future. However, many jurisdictions, especially under-resourced communities in California, lack the capacity, tools, guidance, and resources to effectively prepare for climate impacts.

Adaptation Planning Grant Program

As communities in California experience more frequent, prolonged, and severe impacts from climate change, communities and governments at all scales are developing strategies and implementing actions to build a climate-resilient future. However, many jurisdictions, especially under-resourced communities in California, lack the capacity, tools, guidance, and resources to effectively prepare for climate impacts.

The Adaptation Planning Grant Program addresses this capacity gap by providing funding to help fill planning needs, providing communities with the resources to identify climate resilience priorities, and supporting the development of climate resilience projects across the state. The Adaptation Planning Grant Program enables communities to climate risk and adaptation considerations into planning activities and prepare for climate readiness and resilience in the long term.

The Adaptation Planning Grant is part of the Integrated Climate Adaptation and Resiliency Program (ICARP) housed within the Governor's Office of Land Use and Climate Innovation. ICARP advances statewide climate adaptation and

resilience by coordinating investments, partnerships, and climate science to ensure people, natural systems, and the built environment are protected, prepared, and thrive in the face of climate change.

Through direct and equity-focused investments and resources, ICARP helps build climate adapted and equitable communities in California, with a focus on solutions that address the impacts of climate change and reduce greenhouse gas emissions. ICARP works to advance these priorities across all levels of government by developing actionable science and research; providing guidance, tools, and technical assistance; and administering climate resilience-focused grant programs.

Learn more: https://lci.ca.gov/climate/icarp/

Modeling Methodology

This section defines the criteria for sizing the PV array and BESS system components, detailing general parameters, technical requirements, and expected performance criteria.

PV Modeling

1. **Data Inputs**
    - **Solar Resource**: Hourly or sub-hourly irradiance data (e.g., typical meteorological year or on-site measurements)
    - **Site-Specific Factors**: Tilt angle, azimuth, shading analysis, and available roof/ground space
2. **Simulation Approach**
    - Use of HelioScope software to estimate hourly PV production
3. **Sizing Criteria**
    - **Capacity** The sizing criteria are based on 50% of the facility's current annual energy consumption, with the objective of offsetting the facility's energy usage through the PV array. However, due to space constraints, only 50% of this offset can be achieved. As a result, the final system capacity is limited by the area designated as available by the client.
    - **Performance Ratio**: Evaluate Performance Ratio to ensure consistent system output
    - **Energy Production**: Hourly, daily, monthly, and annual PV generation forecasts
    - **Load Matching**: Amount of PV energy that directly offsets site load vs. excess exported to the grid

BESS Modeling

1. **Data Inputs**
    - **Load Profile**: Detailed electricity consumption and demand patterns
    - **PV Production Profile**: From the PV modeling results
    - **Energy Duration for Resilience**: Determine the critical loads that the BESS will support during islanding operations
2. **Operational Modes**
    - **Energy Shifting / Excess PV Storage**: Battery charges when PV output exceeds site demand, discharges when site demand is high.
    - **Resilience (Standalone BESS)**: Sized to support critical loads during outages
3. **Sizing Criteria**
    - **Capacity (kWh)**: Based on required autonomy (energy shifting, peak shaving, or resilience duration)

- **Max Discharge/Charge Rate (kW)**: Aligned with site load peaks, PV generation surpluses, and emergency power needs

4. **Simulation Approach**
    - Hourly or sub-hourly dispatch modeling to maximize economic benefit (e.g., demand charge reductions or avoided peak rates)
    - Incorporate battery round-trip efficiency, self-discharge, and operational constraints (e.g., partial charge strategies)
5. **Output**
    - **Discharge/Charge Profiles**: Hourly modeling of how the battery is utilized
    - **Cost Savings**: Reduction in energy and demand charges or avoided grid cost
    - **Backup Duration**: If sized for resilience, the total hours/days of critical load coverage

Assumptions

AECOM collected facility data through a request for information process. Energy consumption factors and facility characteristics were identified and integrated in analysis. AECOM used these combined datasets to confirm energy utility consumption baselines. In performing the analysis, AECOM made the following assumptions:

- This report refers to Fire Station 106 (2000 Western Knolls Avenue, Beaumont, CA 92223) and Mesa Lift Station (12940 Potrero Boulevard, Beaumont, CA 92223) as the subject sites of this analysis.
- The monthly and annual electricity consumption is determined using load profile data in the client-provided file "RFI v1.0 Microgrid Feasibility Study 04.17.25 - Beaumont Mesa Lift Station" and "Fire Station 106 - SCE_Usage_8019947558_01-01-25_to_12-11-25" This files contains 35040 load profile data points, which are then consolidated into an 8760 load profile dataset.
- AECOM utilized the Levelized Cost of Energy (LCOE) for the installed cost per watt of PV installations and BESS, as sourced from the National Laboratory of the Rockies (NLR). This data was used to estimate the hypothetical cost of installing the PV array and BESS at the site, as detailed in this report. For an accurate cost estimation, it is necessary to obtain vendor quotes, which are subject to change due to market-dependent time windows. These quotations are typically conducted during the 60% design phase, at which point there is an understanding of the specific equipment ratings and brands to be used.
- This report evaluates the sites' existing electrical infrastructure using customer-provided data on the main breaker and bus capacity, as documented in the client-provided file "FS 106 Electrical plans" and "City of Beaumont Mesa Lift Station - Single Line Diagram." AECOM has assessed whether the existing electrical systems can support the proposed PV array and BESS installation. However, as this is a feasibility study, an on-site assessment is required for a definitive determination. A site visit should be conducted during the advanced design phase, typically at the 30% design stage, to confirm site-specific conditions.
- AECOM has estimated the potential PV generation capacity based on the client-identified available area, as documented in the client-provided files "FS 106 Solar Area" and "Mesa Lift Station - Areas were no solar panels." However, a site assessment is required in later project phases, typically at the 30% design stage, to ensure that the site has the necessary infrastructure for PV array installation. This includes evaluating civil structures, load-bearing capacity, particularly for rooftop installations, and other critical conditions necessary for successful implementation.
- This report treats both sites as a single, privately owned microgrid under the same customer, the City of Beaumont. No sale or resale of electricity occurs, and all generation and distribution serves only municipal loads owned by the same entity. Under this structure, the system is evaluated as one integrated microgrid behind a single point of interconnection with Southern California Edison (SCE), which is consistent with the applicable California regulatory framework and does not constitute an over-the-fence sale or regulated utility activity.
- This report uses a regionalized estimate of general production (kWh) to calculate the amount of greenhouse gas emissions avoided through PV generation. The calculation is based on the U.S. EPA Emissions & Generation Resource Integrated Database (eGRID).
- This report clarifies that other charges such as connection fees, required service charges, and taxes remain unchanged. The analysis focuses solely on the bill components directly affected by the installation of PV and BESS under the NEM 3 framework.

AECOM utilized the following tools in conducting the analysis:

- AECOM Internal Tools: Proprietary tools developed by AECOM for analyzing energy patterns and evaluating system performance in simulated environments. These tools are designed to assess energy costs for applications such as peak shaving, energy trading, etc. in DER implementations.
- HelioScope: Web-based software tool used for the design and performance analysis of photovoltaic systems. It combines system layout design with energy simulation, allowing users to model rooftop, ground-mounted, and canopy PV installations. The software factors in module placement, tilt, azimuth, shading, and local weather data to provide accurate estimates of system capacity and expected energy generation.

Site Information

This study is conducted for Fire Station 106 (2000 Western Knolls Avenue) and Mesa Lift Station (12940 Potrero Boulevard). Together, the sites currently consumes about **416,873 kWh per year**,

Under the stated assumption, both sites are treated as a single, privately owned municipal microgrid for the City of Beaumont, located behind one point of interconnection with SCE. No sale or resale of electricity occurs, and all generation and distribution serve municipal loads owned by the same entity.

In terms of electrical infrastructure, Fire Station 106 consists of a municipal building served by a main switchboard rated at 1000 ampere (A), 208/120 volt (V), three-phase, four-wire, with a 65 kiloampere interrupting capacity (kAIC) rating, located in Electrical Room 106. From this switchboard, feeders distribute power to multiple subpanels serving office and operational areas, with feeder sizes up to 4/0 copper depending on circuit requirements. The site includes an emergency generator rated at 50 kilowatt (kW) (62.5 kilovolt-amperes [kVA] at 0.8 power factor), 208/120 V, three-phase, four-wire, configured as a separately derived system and connected through a 200 A, four-pole automatic transfer switch supplying emergency and legally required standby loads. Calculated feeder voltage drops shown on the drawings range from approximately 0.6% to 2.01%.

Mesa Lift Station is equipped with an existing motor control center designed for 277/480 V alternating current (AC), three-phase service, with a 3000 A main bus, NEMA 3R enclosure, and a 50 kAIC interrupting rating. The site is served by SCE through a 1500 kVA utility transformer at 277/480 V, with parallel service conductors consisting of six 3-inch conduits containing 3x500 thousand circular mils (kcmil) copper conductors and a 1/0 ground. The system includes utility metering, a 3000 A main breaker, and multiple feeder sections serving major process loads such as Pumps 1 through 4 equipped with variable-frequency drives and harmonic filters, sump pumps, grinder systems, motor-operated valves, and auxiliary loads. A 15 kVA control transformer supplies low-voltage 120/240 V control power. The site also incorporates a standby generator rated at 750 kW, 277/480 V, three-phase, four-wire, connected through an automatic transfer switch to support continuous operation of critical process loads.



Figure 1. Site Location

Incentive Programs

AECOM has identified three key incentive programs that could benefit the subject site, focusing on renewable energy production and advanced energy storage systems.

The Investment Tax Credit (ITC) and Production Tax Credit (PTC) are federal incentives that reduce the cost of renewable energy projects. ITC offers a tax credit based on a percentage of upfront investment costs, while PTC provides a per-kilowatt-hour credit for electricity generated over time.

Production Tax Credit

Under this initiative, the project is eligible for a tax credit ranging from 0.3 cents to 1.5 cents per installed kWh. The specific value of the credit is determined by several factors, including the project's adherence to certain requirements such as complying with labor standards and using domestic materials.

The PTC program pays for each kilowatt-hour produced over a 10-year period, with government entities receiving the benefit as direct pay instead of a tax credit. For this project, with an estimated 210,063 kWh per year, the best case at 1.5 ¢/kWh would yield about $3,151 annually, totaling around $31,510 over 10 years.

Investment Tax Credit

The City can take advantage of either the ITC or the PTC, but both cannot be utilized simultaneously. Since construction has not yet commenced, selecting the ITC is the most advantageous option. Under this scenario, the project is limited to the base 30 percent credit because it does not meet any conditions for additional bonus allocations.

The ITC provides an extra 10 percent credit for projects located in federally designated low-income communities. However, according to the 2016–2020 census tract classification shown in Figure 3, the project site is located outside the eligible low-income area. As a result, the project does not qualify for the additional 10 percent bonus and remains capped at the standard 30 percent ITC.

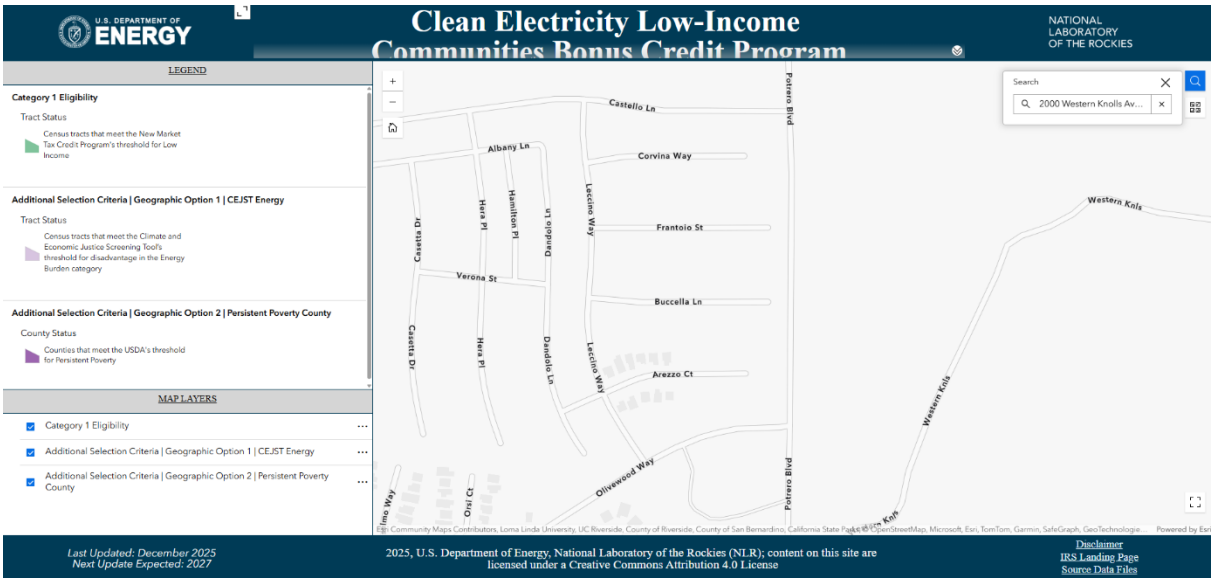


Figure 2. Clean Electricity Low-Income Communities Bonus Credit Program Map

NLR estimates capital expenditure (CAPEX) for commercial PV at $1.75–2.00 / W direct current (DC). For this study, a 121.3 kW-DC PV system is projected. Based on these CAPEX values, total installation cost ranges from $212,275 to 242,600. With the standard 30 percent ITC, the direct-pay benefit for the City would fall between $63,682 and 72,780.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) is California's primary incentive designed to reduce the upfront cost of energy storage systems. The program has three levels:

- **General Market:** For projects located outside Disadvantaged Communities (DAC). Typical incentive: $0.10/Wh.
- **Equity (DAC):** For projects located within a DAC. Incentive: $0.85/Wh.
- **Equity Resilience**: For critical facilities within a DAC and in PSPS or high fire-risk zones. Incentive: $1.00/Wh.

In Case 1, the project site is outside a DAC, so it only qualifies for the General Market level. Using an NLR-based cost of $450/kWh, a 150-kWh battery would cost approximately $67,500. With the General Market incentive of $0.10/Wh, the project would receive about $15,000, resulting in a net battery cost of roughly $52,500.



Figure 3. SB 535 Disadvantaged Communities Map

Scenarios & Analysis

Case 0: Current Situation (Baseline)

Tariff & Contract Type

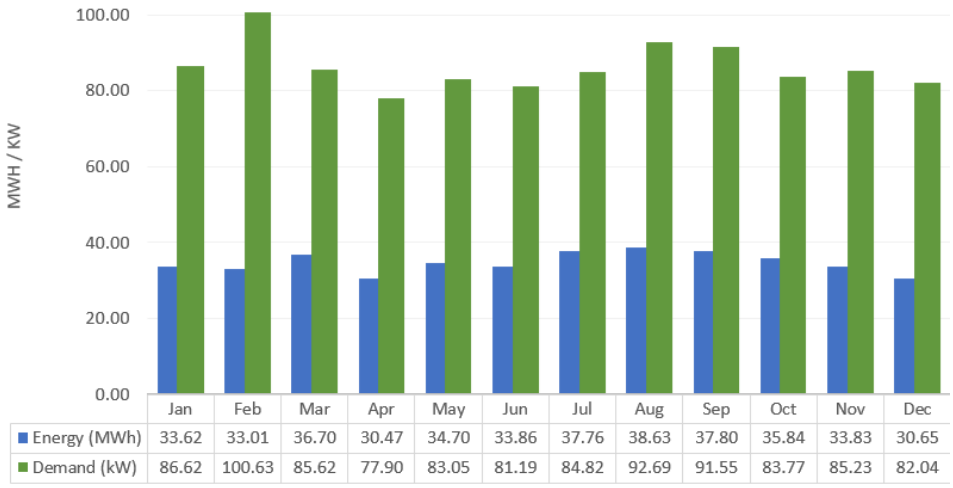
The sites are currently served by Southern California Edison under the TOU-GS-2-E tariff, which is designed for small to medium commercial customers. This rate structure separates costs into energy charges (based on kilowatt-hours consumed) and demand charges (based on the highest kilowatt demand registered during the billing cycle). In addition, prices vary by time-of-use periods—on-peak, mid-peak, and off-peak—so the timing of energy use significantly affects overall costs.

Being on this tariff means the sites' operating expenses are directly tied not only to how much energy is consumed but also to when it is consumed and how high the peak demand reaches.

The tariff cost presents the costs as totals (delivery + bundle). The prices were used as the basis for this study. While they may fluctuate slightly month to month depending on market conditions, these variations are generally minor.

Monthly & Annual Energy Consumption and Demand

The sites currently consume 416,873 kWh annually, with July being the highest month at about 37,700 kWh and April the lowest at about 30,470 kWh. In terms of demand, February records the peak at around 100 kW, while April is the lowest at about 77 kW. The following graph presents this historical data for the 2024–2025 period.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Energy (MWh)	33.62	33.01	36.70	30.47	34.70	33.86	37.76	38.63	37.80	35.84	33.83	30.65
Demand (kW)	86.62	100.63	85.62	77.90	83.05	81.19	84.82	92.69	91.55	83.77	85.23	82.04

Figure 4. Historic Site Energy Profile

Monthly & Annual Energy Costs

The sites currently spend about $115,244 per year in energy and demand cost, with approximately $96,120 in energy costs and $19,124 in demand charges, based on tariff TOU-GS-2-E simulation. For this analysis, we are focusing only on energy and demand costs, as these are the components directly impacted by the installation of a PV system.

Case 1: PV Only

Installed Capacity & Location

The PV system for the site was sized to offset approximately 50% of current consumption, with the goal of offsetting as much as possible of the present usage. The placement areas for the PV installation were identified according to customer requirements. The system capacity is estimated at 121.3 kW-DC, with an expected annual production of about 210,063 kWh.

Figure 6 presented the modeled energy production throughout the year, and Figure 7 identifies the designated PV installation areas on the site.

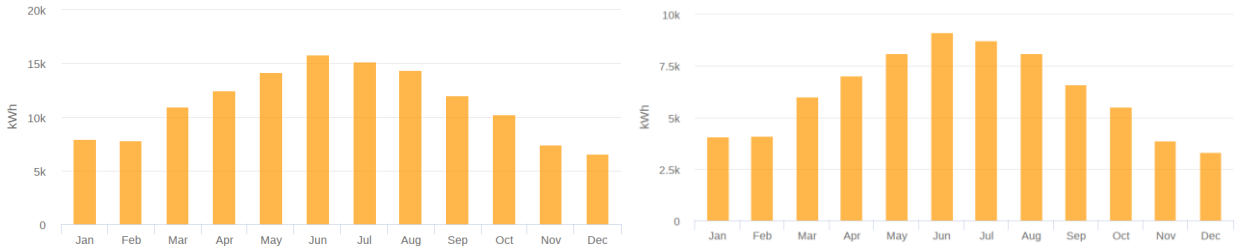


Figure 5. Modeled PV Production



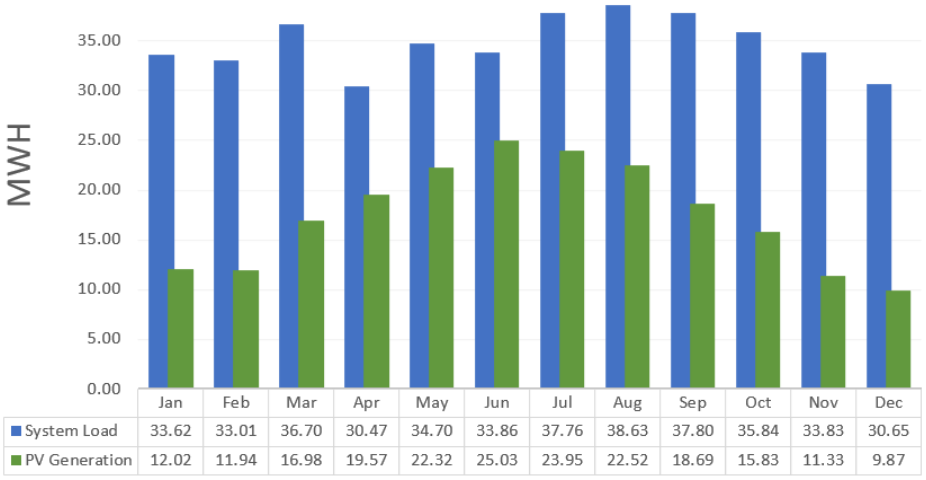
Figure 6. Modeled PV Installation Areas

Modeled PV Production

The modeled PV system is projected to generate an average of **17,505 kWh per month**, with an estimated **annual production of 210,063 kWh**.

This scenario doesn't include a BESS, so the excess energy produced need be exported to the utility, which requires entering a Net Energy Metering (NEM) contract with the utility service provider. Under the currently available NEM tariff, NEM 3.0, exported electricity is credited at dynamic rates that vary by month, hour of day, and weekday, ranging from as low as $0.01/kWh during midday hours to over $1.00/kWh during peak evening hours in high-demand months like August and September. This study has calculated projected benefits from this arrangement.

Figure 8 compares historic monthly energy consumption and modeled PV generation. Not all solar energy will be consumed on-site, as excess daytime production may exceed demand and be exported to the grid, while nighttime demand cannot be covered since there is no generation after sunset and no battery to store the excess in this scenario.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
System Load	33.62	33.01	36.70	30.47	34.70	33.86	37.76	38.63	37.80	35.84	33.83	30.65
PV Generation	12.02	11.94	16.98	19.57	22.32	25.03	23.95	22.52	18.69	15.83	11.33	9.87

Figure 7. Modeled PV Output vs. Site Demand

Capital Expenditures

Based on NLR benchmark CAPEX values for commercial rooftop solar, the estimated cost to install a 121.3 kW DC PV system in Riverside County, California falls in the range of $1.75 to $2.00 per W-DC. This translates to a total investment of **approximately $212,205 to $242,520 for the complete system**.

These figures include **typical equipment, installation, and soft costs**, reflecting average market conditions for commercial-scale projects. Actual costs may vary slightly depending on site-specific conditions such as roof structure, permitting, interconnection requirements, and labor. However, the NLR benchmarks provide a reliable basis for estimating the capital cost of a system of this size and type in the region.

Operating Expenses

According to NLR's 2024 benchmark data, the annual operations and maintenance (OPEX) cost for commercial rooftop PV systems is about $19 per kW-DC. For a 121.3 kW DC system, this translates to an estimated yearly **OPEX of roughly $2,304** covering routine maintenance, monitoring, and related operational expenses.

Economic Metrics

The analysis shows that installing a PV system at the site under NEM3 provides measurable financial benefits by offsetting both energy and demand charges. Without solar, the facility currently spends about **$115,244** annually on utility costs. With the PV system in operation, the energy cost is reduced to approximately **$61,637** per year, while the demand cost drops to about **$18,993** per year. In addition, the system generates excess electricity during the day that cannot be fully consumed on-site. Under NEM3 rules, this exported energy represents an additional benefit of roughly **$2,614** annually.

Taken together, these reductions and export credits bring the facility's total utility bill down to **$78,016 per year**, achieving an **overall savings of about 32%** compared to current expenses

Payback Period and Return on Investment

The financial analysis shows that without PV, the facility spends approximately $115,244 per year on utility costs. With a 121.3 kW DC PV system installed, the annual cost is reduced to about $78,016, resulting in yearly savings of roughly $37,228. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system is estimated at $242,520, but with the 30 percent ITC direct pay, the net investment is reduced to approximately $169,764. In addition, the system carries an annual OPEX of $2,304, which slightly offsets the yearly savings. Taking these factors into account, the project generates a net benefit of about $37,228 minus 2,304 per year after OPEX. This results in a simple payback period of approximately 5 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross Savings ($)	Net Savings after OPEX ($)	Cumulative Cash Flow ($)
1	37,228	34,924	-134,840
2	38,345	35,972	-98,868
3	39,496	37,051	-61,816
4	40,680	38,163	-23,653
5	41,901	39,308	15,654
6	43,158	40,487	56,141
7	44,453	41,702	97,843
8	45,786	42,953	140,795
9	47,160	44,241	185,036
10	48,575	45,568	230,605
15	56,311	52,826	479,792
20	65,280	61,240	768,667

Table 1. Return on Investment w/ 3% Inflation: Case 1

Technical Feasibility

This report treats both sites as a single, privately owned microgrid under the same customer, the City of Beaumont. No sale or resale of electricity occurs, and all generation and distribution serve only municipal loads owned by the same entity. Under this structure, the system is evaluated as one integrated microgrid behind a single point of interconnection with SCE, which is consistent with the applicable California regulatory framework and does not constitute an over-the-fence sale or regulated utility activity.

The existing electrical service is 277/480 V, 3-phase, 4-wire and is supplied from a 1500 kVA utility transformer. The service equipment and distribution are rated 3000 A with a 3000 A main overcurrent protective device feeding a 3000 A motor control center bus (NEMA 3R, 50 kAIC).

A 121.3 kW-DC (110 kW-AC) photovoltaic system interconnected at 480 V, three-phase, produces a nominal inverter output current of 132 A, calculated as 110,000 W divided by $\sqrt{3}$ times 480 V. As a continuous source, the required overcurrent protection device rating is 165 A at 125% loading, resulting in a minimum standard breaker size of 175 A. Under NEC 705.12 busbar loading requirements, a 3000 A bus with a 3000 A main allows up to 600 A of distributed generation backfeed; therefore, the proposed 175 A PV backfeed is fully compliant and provides a 425 A margin below the allowable limit. The PV interconnection shall be executed as a load-side backfeed connection using a 200 A, 3-pole breaker located to satisfy NEC 705.12 busbar loading (opposite-end placement relative to the 3000 A main when both devices are on the same bus structure). Required implementation items include confirming the 50 kAIC short-circuit rating remains adequate with the added source contribution, updating coordination settings as needed, and providing permanent directory placards and source identification for the integrated microgrid point of interconnection and PV disconnecting means.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 210,063 kWh per year. Using the U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:

- Carbon dioxide (CO_2): 89,991 pounds (lbs) (40.82 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 90,327 lbs (40.97 metric tons) avoided annually
- Nitrogen oxides (NO_x): 69.741 lbs (31.634 kg) avoided annually
- Sulfur dioxide (SO_2): 4.201 lbs (1.906 kg) avoided annually

Case 2: PV + BESS

System Components

This scenario assumes the same PV array described in Case 1 and a BESS sized for surplus PV production. The day with the highest energy surplus in our simulation occurred on December 25, during which the PV system produced 343.37 kWh, the site consumed 146.39 kWh, and the resulting surplus was 196.99 kWh. For size the BESS, we ran several iterations based on the available surplus energy and applied an algorithm that simulates the charge and discharge cycles of one year. This techno-financial analysis indicates that the optimal BESS capacity is approximately 430 kWh.

This simulation factor ensures that even under variations in production or demand, all possible excess solar energy generated during the day can be stored. The stored energy is then available for use at night or during periods when PV production does not fully cover the site's demand.

By doing so, most of the units of solar energy produced on-site are consumed daily by the facility, preventing as little as possible any export to the grid.

Modeled Energy Flows

By installing a 150 kWh battery, we ensure that all the energy generated on-site is consumed by the facility itself. The charge and discharge profile of the battery is designed so that any PV surplus during the day is immediately stored in the battery rather than exported to the grid. Later, if the site demand exceeds the PV generation while there is still energy stored in the battery, the deficit is supplied from the battery.

This operational strategy minimizes or even eliminates consumption from the utility, since the PV and battery combination is prioritized to cover the load at all times. On an annual basis, the system is expected to produce slightly more energy than the site requires, leaving a surplus of around 10%, but this excess is negligible in terms of the overall utility bill.

Capital Expenditures

According to NLR benchmark data, the capital expenditure (CAPEX) for a commercial-scale 121.3 kW DC rooftop PV system in Riverside, California is estimated at $169,764 under ITC incentive, based on installation costs of $1.75–2.00 per watt DC.

For storage, NLR's 2025 cost projections indicate a CAPEX of $450 per kWh for the high-cost scenario. Applying this benchmark to a commercial-scale 150 kWh battery system represents an investment of roughly $52,500 and under the SGIP program this amount can be fully covered, effectively funding 29% of the BESS system

Together, the combined CAPEX for the PV and BESS systems is estimated at $2,904 representing the expected upfront investment for a commercial solar-plus-storage project of this size.

Operating Expenses

According to NLR benchmark data, the annual operations and maintenance (OPEX) cost for a commercial-scale 121.3 kW DC rooftop PV system is estimated at $2,304.

NLR data indicates an operating cost of approximately $4 per kW-year. For a commercial-scale 150 kWh battery system, this results in an annual OPEX of about $600.

Together, the **combined OPEX for the PV and BESS systems** is approximately **$2,904 per year**, covering routine maintenance, monitoring, and system management.

Economic Metrics

The analysis shows that installing a commercial-scale PV system paired with a 150 kWh battery under NEM 3 provides strong financial advantages by allowing a substantial portion of the solar energy produced by the PV system to be consumed on-site.

In several cases, PV production exceeds the facility's demand, and the surplus can be stored in the BESS for later use. However, without a battery system, the facility cannot absorb all of this excess energy, since any unused generation must be consumed the moment it is produced. This unused energy would otherwise need to be exported to the utility grid, where under current NEM rules it would be compensated at only about 25 percent of the retail electricity rate. Given that time-of-use pricing makes stored energy far more valuable during high-cost periods, it becomes financially preferable to store surplus solar rather than sell it

Without a BESS, exporting this excess would generate $2,614 but the facility would still face an annual utility cost of $78,016 By contrast, installing the BESS reduces grid reliance and allows the facility to consume nearly all of its solar production during higher-priced periods, resulting in a significantly lower annual utility bill of $67,091

To remain conservative, this analysis assumes that 10% of annual energy costs remain due to efficiency losses, imperfect alignment of PV output and site load, and seasonal variability.

It is important to note that other charges—such as connection fees, requisite charges, and taxes—remain unaffected. This analysis focuses only on those bill components directly impacted by the installation of PV and BESS under the NEM 3 framework.

Payback Period and Return on Investment

The financial analysis shows that without PV + BESS, the facility spends approximately $115,244 per year on utility costs. With a 121.3 kW DC PV system and 150 kWh BESS system installed, the annual cost is reduced to about $67,091 resulting in yearly savings of roughly $48,153. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system under ITC and SGIP incentives is estimated at $222,264. In addition, the system carries an annual OPEX of $2,904 Taking these factors into account, the combined system generates a net benefit of about 45,249 per year after OPEX. This results in a simple payback period of approximately 5 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross-Savings ($)	Net-Savings after OPEX ($)	Cumulative Cash Flow ($)
1	48,153	45,249	-177,015
2	49,597	46,606	-130,409
3	51,085	48,004	-82,404
4	52,618	49,445	-32,960
5	54,196	50,928	17,968
6	55,822	52,456	70,424
7	57,497	54,029	124,453
8	59,222	55,650	180,104
9	60,999	57,320	237,423
10	62,828	59,039	296,463
15	72,835	68,443	619,315
20	84,436	79,344	993,588

Table 2. Return on Investment w/ 3% Inflation: Case 2

Technical Feasibility

The one-line diagrams show two existing electrical systems that would be treated as one integrated customer-owned microgrid: (1) an existing outdoor motor control center (MCC) rated 277/480 V, 3-phase, 3000 A with an automatic transfer switch (ATS) and a 277/480 V standby generator, and (2) a separate main switchboard “MS” rated 208Y/120 V, 3-phase, 4-wire, 1000 A with an ATS and a 208Y/120 V standby generator.

To interconnect an additional 110 kW AC PV system, the preferred approach is to land the PV on the highest-capacity distribution bus that has adequate physical space, fault duty rating, and feeder capacity. At 480 V, a 110 kW PV inverter output is approximately 132 A and would typically require a dedicated 3-pole backfeed breaker on the order of 150 A, plus a lockable visible PV AC disconnect.

Because the diagrams show two different utilization voltages (277/480 V and 208Y/120 V), the PV and BESS PCS output voltage must match the selected interconnection bus. If the PV or BESS is physically installed at the opposite voltage level, include an appropriately sized step-up or step-down transformer and a dedicated feeder to the chosen switchboard or MCC section.

For a load-side connection, perform an NEC 705.12 bus and breaker sum check at the exact point of interconnection. The 3000 A, 480 V MCC bus provides significantly more headroom for adding PV and a BESS breaker than the 1000 A, 208 V main switchboard, but the final determination must be based on the actual bus ratings, main sizes, and the final BESS PCS breaker size shown on the as-built equipment labels.

Install a dedicated BESS PCS breaker (size based on the final PCS kW rating, not the 150 kWh energy rating) at the selected bus, and confirm conductor sizes, conduit routing, and spare breaker space are available for the new PV and BESS feeders. If spare space is not available, add a new distribution section or a small, dedicated DER panelboard with a properly rated main and bus.

Before construction, complete a protection and interconnection review for both service points, including short-circuit duty, grounding and bonding, breaker coordination, and generator/ATS interaction with inverter-based resources. For SCE interconnection, provide utility-required metering, labeling, and a visible, lockable AC disconnect, and confirm the PV inverter and BESS PCS comply with IEEE 1547 / UL 1741 requirements and any SCE protection settings or export limits.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 210,063 kWh per year. Using the U.S. EPA’s Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:”

- Carbon dioxide (CO_2): 89,991 lbs (40.82 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 90,327 lbs (40.97 metric tons) avoided annually
- Nitrogen oxides (NO_x): 69.741 lbs (31.634 kg) avoided annually
- Sulfur dioxide (SO_2): 4.201 lbs (1.906 kg) avoided annually

CASE 3: BESS Only

Critical Load Identification

For a Community Center, NEC 700 and NFPA 72 require emergency power for egress illumination, fire alarm systems, and associated notification and control circuits. NEC 701 applies to legally required standby loads that support public safety functions, including limited communications, security, and access control where provided. The one-line diagrams show an ATS and dedicated standby generation feeding selected distribution sections, indicating segregation between normal and emergency systems. Based on these requirements and the facility type, the critical load is estimated at 175 kW, representing the portion of load associated with life-safety lighting, fire alarm power supplies, and legally required standby systems.

Required Backup Duration

For the sites, maintaining continuous operation of alarm systems, emergency communications, lighting, and fuel dispensing is essential to guarantee mission readiness. According to NFPA 110 (Section 4.2 and 7.12.1), emergency power supply systems (EPSS) must provide a minimum of 2 hours of operation at full rated load. However, because fire stations are classified as critical public safety facilities, most Authorities Having Jurisdiction (AHJs) and best practice guidelines require at least 4 hours of backup capacity to ensure firefighters can respond to emergencies during extended outages.

Battery Capacity & Infrastructure

The battery energy storage system is sized directly from the emergency load and required duration. An emergency demand of 175.0 kW sustained for 4 hours results in a required usable energy capacity of 700 kWh. The BESS power rating is set equal to the emergency load to allow full support of all identified life-safety and legally required standby circuits. Integration would occur on the emergency distribution side of the ATS shown in the one-line diagrams, requiring sufficient bus capacity, a dedicated feeder and breaker for the BESS, and coordination with the existing standby generator to avoid backfeed into normal distribution.

Capital Expenditures

Using cost benchmarks published by the National Laboratory of the Rockies (NLR), the estimated **capital cost** (CAPEX) for a 700 kWh / 175 kW battery energy storage system is approximately $**245,000**. This figure includes the battery cabinets, inverter/PCS, microgrid controller with ATS, installation, protections, and engineering.

Operating Expenses

The expected **operating cost** (OPEX) is about **$2,800 per year**, also based on NLR reference values. This covers preventive maintenance, monitoring software, and NFPA 110 testing requirements. Battery replacement is typically required after 10–12 years of service.

Return on Investment & Qualitative Benefits

While a conventional financial return cannot be directly applied to this case, the value of a BESS for a Community Center is framed in terms of resilience, reliability, and compliance. Such systems are designed to ensure uninterrupted operation of life-safety and mission-critical equipment during extended utility outages. The benefits include maintaining operational continuity, reducing safety risks, and ensuring compliance with NFPA 110, NFPA 70, and NFPA 72.

However, for these particular sites, the justification for a BESS must be evaluated against the existing backup assets visible in the drawings, including standby generators. If the generator capacities already exceed the critical load requirement, the incremental resilience provided by the BESS may be limited relative to cost. In these situations, the decision typically shifts from technical necessity to redundancy preferences, policy considerations, or long-term reliability planning.

Technical Considerations

Integration of a BESS into the existing electrical architecture requires verification of emergency bus capacity and compliance with load-side interconnection limits, including the 120 percent rule where applicable. Breaker sizing and feeder ampacity must be coordinated with the added source, and the ATS must clearly separate normal and emergency circuits. Short-circuit and coordination studies are required to confirm fault duties with the additional inverter source. Transfer sequencing between utility, generator, and BESS must be validated, and system design must address fire and thermal risk through appropriate listing and UL 9540A-based mitigation consistent with the equipment placement shown in the drawings.

Decision Matrix and Scenario Comparison

In order to determine the most appropriate scenario for the site, four scenarios were developed and analyzed: business as usual (Case 0), installing a PV system only (Case 1), installing PV with a BESS (Case 2), and installing a BESS only (Case 3). Each case was evaluated in terms of resilience value, capital and operating expenditures, energy savings, payback period, and technical feasibility. The decision matrix summarizes the comparative performance of these options.

Criteria	Case 0: Baseline	Case 1: PV Only	Case 2: PV + BESS	Case 3: BESS Only
Resilience Benefit	None	Limited (daytime only)	Moderate (self-consumption, some coverage)	High (but redundant due to existing 125 kW generator)
CAPEX ($)	0	$212k – $242k	~$222k (PV + BESS after ITC and SGIP)	~$245k
OPEX ($/yr)	Current $24k	~$2,304	~$2,904	~$2,800
Annual Utility Bill ($)	~$115,244	~$78,016	~$67,091	~$115,244 (no reduction)
Annual Savings ($)	–	~$37,228	~$48,153	Minimal (non-financial)
Payback Period	–	~5 years	~5 years	No ROI
GHG Reduction	None	~40.9 $MTCO_2e$ avoided annually	Same as Case 1	None
Technical Feasibility	Already in place	Straightforward load-side PV interconnection at 480 V	Requires breaker + storage integration	Technically feasible but unjustified given existing generator capacity

Table 3. Scenario Comparison

Conclusion

Based on the comparative analysis, **Case 2 (PV + BESS)** emerges as the preferred scenario for the sites. While Case 1 (PV-only) generates meaningful utility cost savings through on-site solar production, its benefits are limited by the inability to fully utilize excess generation under the current NEM 3 framework. By contrast, Case 2 delivers higher annual savings by storing surplus daytime solar energy and shifting its use to higher-cost evening and nighttime periods. Case 3 (BESS-only) was not selected, as both sites are already equipped with standby generators capable of supporting identified critical and legally required loads, making a standalone battery system largely redundant for resilience purposes.

Case 2 builds upon the advantages of Case 1 by incorporating a battery energy storage system that enables surplus solar energy to be stored and later discharged during higher-cost evening and nighttime periods. This significantly increases on-site energy utilization, further reduces annual utility costs, and improves operational flexibility. Although the inclusion of a BESS increases capital cost and system complexity relative to PV-only, these impacts are mitigated by available incentives such as the federal Investment Tax Credit and California's Self-Generation Incentive Program. Under these conditions, Case 2 delivers the lowest annual utility cost among all evaluated scenarios while maintaining a competitive simple payback period.

Microgrid Integration of Both Sites

This study evaluates both sites as a single, customer-owned municipal microgrid operated by the City of Beaumont behind one utility meter and one point of interconnection with Southern California Edison. Under California's regulatory framework, this configuration is permissible provided that all generation and loads are owned by the same legal entity and that no sale or resale of electricity occurs. Under these conditions, the system is treated as a private electrical network serving municipal facilities and does not constitute an over-the-fence sale or regulated utility activity.

The feasibility of this configuration is based on the following requirements: common ownership of both parcels by the City of Beaumont, exclusive service of municipal loads, and placement of all inter-site electrical distribution downstream of the utility point of interconnection. When these conditions are met, California utility regulations and interconnection rules allow multiple facilities to operate as a single microgrid under one meter, subject to utility approval and compliance with applicable interconnection, protection, and safety requirements.

To electrically connect the two sites, customer-owned infrastructure would be required to physically interconnect both parcels. This would typically include dedicated electrical feeders installed in underground conduit or duct banks, appropriate overcurrent protection, grounding and bonding continuity, and coordination with existing switchgear, standby generators, and inverter-based resources. Detailed protection, short-circuit, and coordination studies would be required to confirm that the interconnected system operates safely under both normal and abnormal conditions.

The capital cost associated with constructing the electrical interconnection between the two sites is not included in this feasibility study. These costs depend on routing distance, trenching conditions, permitting requirements, and site-specific constraints, and would require additional field investigation and design development to accurately quantify. As such, this report focuses on the generation and storage systems, with inter-site electrical infrastructure to be evaluated in a subsequent project phases.

Summary of Strategy & Benefits

The selected strategy focuses on installing a rooftop PV system sized to offset 110% of the facility's annual energy consumption. This approach achieves the following benefits:

- **Resilience:** Self-generation capacity reduces the reliance on utility service provider
- **Economic Savings:** Reduces annual utility costs by ~42%, from about $24,182 to $14,090
- **Financial Feasibility:** Delivers a simple payback of approximately 8 years, after which the station continues to accrue savings for the remaining system life
- **Environmental Impact:** Offsets approximately 17 metric tons of CO_2 emissions annually, directly contributing to local and regional climate goals
- **Technical Simplicity:** Requires only a minor breaker adjustment to comply with NEC 705.12 busbar requirements, avoiding major infrastructure upgrades
- **Operational Practicality:** Provides long-term stability in operating expenses without introducing unnecessary complexity in operations or maintenance

Next Steps

To advance the project, the following steps are recommended:

1. **Detailed Design & Site Assessment:** Conduct a 30% design phase evaluation, including structural assessment of the roof, electrical interconnection details, and shading analysis
2. **Vendor Quotations:** Obtain updated vendor quotes for PV system equipment, installation, and interconnection to refine cost estimates beyond NLR benchmarks
3. **Permitting & Interconnection:** Coordinate with Southern California Edison (SCE) to complete the interconnection study and ensure compliance with NEM 3 tariff rules
4. **Finalize Incentive Applications:** Submit applications for the 30% ITC (direct pay) to secure federal funding and reduce upfront capital cost
5. **Procurement & Installation:** Issue RFPs for procurement and construction, selecting qualified contractors with experience in municipal PV installations
6. **Commissioning & Monitoring:** Upon installation, perform commissioning tests, integrate the system with monitoring platforms, and establish an operations and maintenance (O&M) plan to ensure reliable long-term performance

Appendix

Incentive Programs

This section outlines how the incentive programs function and provides relevant information about them. Specific application of these programs to presented scenarios is explored in previous sections.

Inflation Reduction Act

The Inflation Reduction Act of 2022 stands as a significant piece of legislation designed to strengthen the United States' commitment to fighting climate change by making considerable investments in renewable energy. A key feature of the Inflation Reduction Act is its financial incentives, namely the Investment Tax Credit (ITC) and the Production Tax Credit (PTC), which aim to accelerate the adoption of renewable energy technologies.

The ITC allows for a significant tax credit for investments in renewable energy technologies, including solar panels and wind turbines, directly reducing the upfront cost of these systems. This makes renewable projects more financially viable and attractive to investors and consumers alike. On the other hand, the PTC provides a per-kilowatt-hour tax relief for the production of energy from renewable sources, incentivizing the operation and expansion of renewable energy facilities.

Notably, Inflation Reduction Act programs have been subject to change in recent legislation. Presented here are active opportunities as of the time of the report.

Production Tax Credit

The Production Tax Credit (PTC) within the framework of the Inflation Reduction Act offers considerable financial incentives for renewable energy projects, primarily designed to decrease the federal income tax liability based on the electricity produced per kilowatt-hour.

The PTC directly reduces the federal income tax for taxable entities. Furthermore, for non-taxable entities such as local governments, educational institutions, or nonprofit organizations, the PTC allows these credits to be monetized, facilitating their involvement in renewable energy initiatives. This provision is applicable for projects that become operational between January 1, 2023, and December 31, 2032, providing a broad window for planning and implementation.

Projects located in designated low-income energy communities receive further incentives. The PTC is structured to be claimable annually for a decade from the start date of operations of the qualifying renewable system, providing long-term financial support. This current structure of the PTC is set to continue through the end of 2024. Starting from January 1, 2025, the credit system will transition to a technology-neutral format, broadening the scope to include a wider array of technologies and fostering a more inclusive approach to renewable energy incentives.

As of the date of this report, the program is still active but solar projects must have “begun construction” by July 4, 2026.

The City project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

Investment Tax Credit

The Investment Tax Credit (ITC) established under the Inflation Reduction Act offers a powerful incentive for deploying renewable energy technologies by providing a reduction in federal tax liability. This reduction is calculated as a percentage of the capital investment made in eligible energy systems. Taxpayers can apply the ITC to their federal income tax for the year the technology is installed, significantly decreasing their tax burden.

Starting January 1, 2023, special provisions enable tax-exempt entities such as local governments and nonprofits to receive direct payments equivalent to the value of the credit. This arrangement improves the liquidity and financial feasibility of renewable projects for these organizations. The scope of eligible technologies under the ITC is broad, encompassing solar panels, wind turbines, fuel cells, and other renewable energy systems.

As of 2025, the Investment Tax Credit (ITC) for solar projects is set at 30% of the eligible costs, encompassing both the equipment and installation expenses. This rate is scheduled to decrease to 26% in 2033 and further to 22% in 2034. Systems rated under 1 megawatt (MW) qualify for the full 30% without having to comply with additional requirements; larger systems will only receive the full amount if they meet specific labor requirements. These include paying prevailing wages to workers during construction and using apprentices to perform a portion of the total construction hours (15% after 2023). Bonus credits are available based on site location, e.g. low-income communities.

The ITC is set to continue delivering these benefits at its current rate until 2032, contingent upon meeting the specific project criteria laid out in the act. Looking ahead, post-2024, the ITC will transition to a technology-neutral system, which will be applicable to all zero-emissions technologies, reflecting a shift towards a more inclusive and adaptable approach to supporting renewable energy development.

HHZP project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

As of the date of this report, the program is still active but critical deadlines for project eligibility and complete operability are quickly approaching in 2026 and 2027, respectively.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) offers financial incentives to non-residential customers of utility Company to encourage the adoption of energy storage systems. These systems help businesses prepare for power outages that may occur due to weather, emergencies, or other unforeseen events. The SGIP funding is authorized through 2024, with incentives structured to decrease over time as funding milestones are reached or as more participants enter the program.

Non-residential customers have access to three types of SGIP rebates: General Market, Equity, and Equity Resilience. Furthermore, SGIP incentives are significantly higher for vulnerable or disadvantaged communities through the Equity and Equity Resilience categories.

Incentives are typically paid upfront for residential systems upon project completion and site verification, while nonresidential systems may receive half upfront with the balance paid based on the system's performance over time. Eligibility for SGIP incentives extends to residential, commercial, industrial, agricultural, and municipal customers of specific utilities including Pacific Gas & Electric, Southern California Edison, SoCalGas, San Diego Gas & Electric, and those managed by the Center for Sustainable Energy.

To be eligible for this rebate, a facility must satisfy two conditions: firstly, it must fall under the category of a government agency, educational institution, non-profit organization, or small business. Secondly, it must fulfill at least one of the following requirements: be located in a Disadvantaged Community (DAC), be situated in a census tract where the Median Household Income of the Statewide Median Income or be situated in California Indian Country.

On the other hand, the equity resilience rebate offers a rate, covering a percentage of the cost of an average energy storage system. To qualify for this rebate, a facility must meet certain requirements. Firstly, it must have experienced two or more utility Public Safety Power Shut-offs (PSPS), or it should be located in a Tier 2 or 3 High Fire Threat District (HFTD) and serve customers in DACs or Low Income Communities. Secondly, it must fulfill at least one of the following additional criteria:

- Be a police station, fire station, emergency response provider, emergency operations center, 911 call center, medical facility, private and public natural gas, electric, water, wastewater, or flood facility, jail or prison, utility-designated PSPS assistance center, cooling center, homeless shelter.
- Be a grocery store, supermarket, or corner store with less than $15 million in annual gross receipts.

- Be an Independent Living Center or a Food Bank.

Modeling Assumptions

The modeling conducted for this feasibility study was based on standard industry benchmarks, available site data, and conservative assumptions to ensure realistic projections. The following key assumptions were applied:

1. **Energy Consumption Baseline** – Historical hourly load data (8,760 points) from the facility was consolidated to represent a typical annual profile. This served as the reference for sizing PV and BESS systems.
2. **PV System Costs** – Capital expenditure (CAPEX) and operations and maintenance (OPEX) values were derived from the National Laboratory of the Rockies (NLR) 2024–2025 benchmarks for commercial rooftop systems. PV CAPEX was assumed at $1.75–$2.00/Wdc, with OPEX at ~$19/kW-year.
3. **BESS Costs** – Battery energy storage CAPEX was modeled using NLR 2025 benchmarks at ~$350/kWh. OPEX was assumed at ~$40/kW-year, covering maintenance, monitoring, and lifecycle management.
4. **ITC Incentives** – A 30% Investment Tax Credit (direct pay) was assumed, reducing upfront project cost. No additional low-income or disadvantaged community adders were included, since the site does not qualify.
5. **Performance Parameters** –
    - PV generation modeled with HelioScope using site tilt, azimuth, and shading factors.
    - Battery modeled with 90% round-trip efficiency and daily cycling where applicable.
    - Energy inflation rate of 3% annually applied to utility costs.
6. **Utility Tariff** – The analysis used the most recent Southern California Edison tariff, **TOU-GS-2 Option D**, as published in the file *ELECTRIC_SCHEDULES_TOU-GS-2_2025*. It was assumed under the current **NEM 3** framework. Exported PV energy was valued at ~25% of retail rate. Since tariff structures and prices are subject to future changes, the financial outcomes presented here should be viewed as indicative estimates rather than fixed projections.
7. **Infrastructure** – Electrical interconnection feasibility was preliminarily evaluated using customer-provided single-line diagrams. Minor breaker adjustment (600 A to 500 A) was assumed to comply with NEC 705.12 120% busbar rule for PV backfeed.
8. **Environmental Impact** – Greenhouse gas (GHG) reduction estimates were calculated using EPA eGRID emission factors for the CAMX subregion, applied to modeled PV generation.

Disclaimer: These figures are rough estimates intended for feasibility-level evaluation. If more precise values are required, additional detail must be developed through site-specific engineering, vendor quotations, and utility coordination during the advanced design phase.

Net Energy Metering

Net Energy Metering (NEM) in California is a billing arrangement that allows residential and commercial customers who generate their own electricity, primarily through solar photovoltaic (PV) systems, to receive credit for the surplus energy they contribute to the grid. This system is designed to incentivize the use of renewable energy sources by offsetting the cost of electricity consumption with the energy produced by these installations.

Under NEM, when a solar system generates more electricity than is consumed, the excess energy is sent back to the utility grid, and the customer earns credits. These credits can then be used to offset the cost of energy drawn from the grid when the solar system isn't producing enough to meet the customer's demand, like during nighttime or cloudy days. The rules, rates, and credits under NEM can vary over time, with different iterations such as NEM 1, 2, and the latest NEM 3, each having specific regulations and compensation structures for solar energy production and exchange.

The transition from NEM 2 to NEM 3 in California, which was effective on April 14, 2023, introduced significant changes in the net metering policies for utility customers with photovoltaic (PV) systems. These changes impact

several aspects, particularly the economics of energy arbitrage between PV system owners and the utility. Here's a summary of the key changes:

1) **Reduction in Export Rates:** Under NEM 3, there's a substantial reduction in the rates for excess electricity exported onto the grid by solar systems. This rate has been reduced by approximately 75%, thereby lowering the overall savings for home solar systems and increasing the payback period. This change is a shift from the traditional one-to-one offset of net metering policies, where the price of a kWh of electricity pushed onto the grid was equal to the price of a kWh pulled off the grid.
2) **Implementation of Electrification Rates:** Customers enrolling in NEM 3 are required to use electrification rates instead of regular Time-of-Use (TOU) rates. These electrification rates feature higher on-peak charges and lower off-peak charges, along with a fixed charge of $15 per month. The peak rate period remains from 4 pm to 9 pm.
3) **Export Compensation Based on Avoided Cost Calculator (ACC):** Export compensation under NEM 3 is determined by California's ACC, with specific export rates for every combination of Month, Hour, and Weekday or Weekend. The export value is lowest in the middle of the day when solar energy is abundant on the grid and highest during peak summer demand periods. Notably, the export rates are significantly lower than retail rates during the hours when PV systems are most productive (10 am – 3 pm). To maintain the financial viability of solar PV systems, customers in PG&E and SCE service territories receive an adder on top of the ACC rate, ranging between 2.2 and 9 cents depending on location and customer class.
4) **Shift to a Cost Avoidance System:** NEM 3 introduces a cost avoidance system for exported electricity. This system pays customers the lowest amount a company can pay under the Public Utility Regulatory Policies Act of 1978 (PURPA), which is significantly less than the typical retail rate. This results in customers receiving, on average, 75% less for the electricity they sell back to the grid, with rates varying by month and by hour.
5) **Grandfathering NEM 2 under NEM 3:** Under the recent NEM 3 policy in California, existing customers with a photovoltaic (PV) system installed under NEM 2 can retain the benefits and terms of their NEM 2 agreement, a process known as "grandfathering." However, these customers are restricted from replacing or adding capacity to their PV systems if they wish to maintain their NEM 2 status, as any significant modifications would require transitioning to the terms of NEM 3.

The Net Energy Metering (NEM) 3.0 policy introduces transformative changes, particularly enhancing the value of utilizing Battery Energy Storage Systems (BESS) for owners of solar power systems. A significant aspect of NEM 3.0 is the reduction in compensation rates for surplus electricity fed back into the grid by solar systems, now down to 75%. This adjustment shifts the financial dynamics, making it less lucrative to export excess solar energy to the grid. Instead, storing this surplus energy in a BESS and utilizing it when energy costs are higher becomes a more financially savvy approach.

The utility of BESS extends beyond merely optimizing the use of solar energy. It offers several additional advantages, such as providing backup power during utility blackouts, mitigating charges associated with demand peaks, and enabling energy arbitrage. Energy arbitrage under this system allows for the charging of BESS not only with excess solar energy but also with cheaper grid energy during low-cost periods. This stored energy can then be used in lieu of more expensive grid power at peak times, effectively reducing reliance on utility-supplied energy. Consequently, NEM 3.0 not only promotes more efficient use of solar energy but also broadens the scope of BESS applications, contributing to a more versatile and resilient energy management strategy.

AECOM



Microgrid Feasibility Study
City of Canyon Lake

Site:
City Hall
31516 Railroad Canyon Rd, Canyon Lake, CA 92587

February 2026

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Executive Summary

This study appraises the viability and benefits of distributed energy resource implementation scenarios at the subject site. Four scenarios were developed and evaluated, with key performance metrics summarized below:

Case	Components	CAPEX ($)	Utility Savings (%)	Annual Bill Reduction ($)	Payback Period (years)	GHG Reduction ($MTCO_2e/yr$)
1	PV Only	~$49k–$56k (≈$39k net ITC)	~43%	~$9,181	~4–5	~10
2	PV + BESS	~$54.8k after ITC	~82%	~$17,661	~4	~10
3	BESS Only	~$10.5k after ITC	0%	$0	No ROI	None
0	Business-as-usual	$0	0%	$0	N/A	None

Note: All values are approximate and subject to final design and incentive approval.

- **Case 1**: **Photovoltaic (PV) array** – Introduces on-site generation and provides meaningful utility cost reductions with moderate resilience benefits limited to daytime operation.
- **Case 2: PV + battery energy storage system (BESS)** – Combines on-site generation with energy storage, enabling near-complete self-consumption of solar energy under NEM 3, significantly reducing grid reliance. The availability of SGIP incentives materially improves project economics by potentially covering up to 100% of the battery system cost, resulting in accelerated payback and enhanced operational flexibility.
- **Case 3: BESS only** – Provides resilience benefits but does not materially reduce annual utility costs and lacks a clear financial return when deployed without on-site generation.
- **Case 0: Business-as-usual** – Maintains full dependence on utility service with no improvement in resilience, cost stability, or emissions reduction.

Considering the results across economic performance, resilience value, environmental impact, and technical feasibility, **Case 2 (PV + BESS)** is identified as the preferred path forward. This scenario delivers the highest annual savings, the fastest payback period, and enhances operational resilience without introducing excessive system complexity.

Recommended Next Steps

1. Advance the project to a 30% design phase, including site verification, electrical system validation, and structural assessments for PV installation.
2. Obtain vendor-specific quotations for both PV and BESS systems to refine capital and installation cost estimates.
3. Initiate utility interconnection and permitting with Southern California Edison under the current NEM 3.0 framework.
4. Secure applicable federal incentives, including the 30% Investment Tax Credit and SGIP funding for the battery system.
5. Develop procurement and construction planning with the goal of implementation within the next available budget cycle.

The intent of this assessment is to support a data-driven decision by demonstrating that a PV + BESS strategy offers the most favorable balance of economic performance, incentive optimization, emissions reduction, and resilience enhancement for the subject site under current regulatory and market conditions.

Background

Purpose

In recent years, especially within the past decade, the impacts of extreme heat and wildfires have been profound through the Inland Empire. Power service disruptions have been increasing in frequency and severity throughout Riverside County, affecting the availability of essential services and community resources.

In 2023, the Western Riverside Council of Governments (WRCOG) received an award (Grant Agreement OPR23145) from the Adaptation Planning Grant Program of the California Governor's Office of Land Use & Climate Innovation Integrated Climate Adaptation and Resilience Program. This program provides funding to help fill local, regional, and tribal planning needs, provides communities the resources to identify climate resilience priorities, and supports the development of a pipeline of climate-resilient infrastructure projects across the state.

As part of this grant-funded project, the Energy Resilience Plan 2.0, WRCOG commissioned microgrid feasibility studies for its member agencies. These studies serve to provide valuation of a potential microgrid at a community-essential facility, as designated by the member agency.

The site selected for the City of Canyon Lake is the City Hall located at 31516 Railroad Canyon Rd, Canyon Lake, CA 92587

This study presents key insights and findings from the evaluation of distributed energy resource (DER) scenarios, including photovoltaic (PV) array and battery energy storage system (BESS) components, at the subject site. It includes analysis of the site's historic energy demand profile and appraises potential PV array and BESS sizing and siting scenarios accordingly. Notably, the study includes assessment of the generation and storage requirements to support the site's critical loads to enable resilience for a specified number of hours during power service disruptions.

Furthermore, this study outlines the financial implications of self-generation, including estimated cost savings, return on investment (ROI), and potential financing options for the project.

It is important to note that this study serves as a preliminary technical and financial assessment. Its purpose is to provide the City of Canyon Lake with the information to make an informed decision on whether to proceed to next phases of microgrid implementation before committing to detailed engineering design and further investment.

Adaptation Planning Grant Program

As communities in California experience more frequent, prolonged, and severe impacts from climate change, communities and governments at all scales are developing strategies and implementing actions to build a climate-resilient future. However, many jurisdictions, especially under-resourced communities in California, lack the capacity, tools, guidance, and resources to effectively prepare for climate impacts.

The Adaptation Planning Grant Program addresses this capacity gap by providing funding to help fill planning needs, providing communities with the resources to identify climate resilience priorities, and supporting the development of climate resilience projects across the state. The Adaptation Planning Grant Program enables communities to climate risk and adaptation considerations into planning activities and prepare for climate readiness and resilience in the long term.

The Adaptation Planning Grant is part of the Integrated Climate Adaptation and Resiliency Program (ICARP) housed within the Governor's Office of Land Use and Climate Innovation. ICARP advances statewide climate adaptation and resilience by coordinating investments, partnerships, and climate science to ensure people, natural systems, and the built environment are protected, prepared, and thrive in the face of climate change.

Through direct and equity-focused investments and resources, ICARP helps build climate adapted and equitable communities in California, with a focus on solutions that address the impacts of climate change and reduce greenhouse gas emissions. ICARP works to advance these priorities across all levels of government by developing

actionable science and research; providing guidance, tools, and technical assistance; and administering climate resilience-focused grant programs.

Learn more: https://lci.ca.gov/climate/icarp/

Modeling Methodology

This section defines the criteria for sizing the PV array and BESS system components, detailing general parameters, technical requirements, and expected performance criteria.

PV Modeling

1. **Data Inputs**
    - **Solar Resource**: Hourly or sub-hourly irradiance data (e.g., typical meteorological year or on-site measurements)
    - **Site-Specific Factors**: Tilt angle, azimuth, shading analysis, and available roof/ground space
2. **Simulation Approach**
    - Use of HelioScope software to estimate hourly PV production
3. **Sizing Criteria**
    - **Capacity Target**: The system is sized to cover 95% of the facility's current annual energy consumption. This approach is intended to offset most of the facility's energy use with the PV array. Due to site space limitations, there is no remaining capacity to accommodate future load growth. The final PV system size is ultimately limited by the area identified by the client as available for installation.
    - **Performance Ratio**: Evaluate Performance Ratio to ensure consistent system output
    - **Energy Production**: Hourly, daily, monthly, and annual PV generation forecasts
    - **Load Matching**: Amount of PV energy that directly offsets site load vs. excess exported to the grid

BESS Modeling

1. **Data Inputs**
    - **Load Profile**: Detailed electricity consumption and demand patterns
    - **PV Production Profile**: From the PV modeling results
    - **Energy Duration for Resilience**: Determine the critical loads that the BESS will support during islanding operations
2. **Operational Modes**
    - **Energy Shifting / Excess PV Storage**: Battery charges when PV output exceeds site demand, discharges when site demand is high.
    - **Resilience (Standalone BESS)**: Sized to support critical loads during outages
3. **Sizing Criteria**
    - **Capacity (kWh)**: Based on required autonomy (energy shifting, peak shaving, or resilience duration)
    - **Max Discharge/Charge Rate (kW)**: Aligned with site load peaks, PV generation surpluses, and emergency power needs
4. **Simulation Approach**
    - Hourly or sub-hourly dispatch modeling to maximize economic benefit (e.g., demand charge reductions or avoided peak rates)

- Incorporate battery round-trip efficiency, self-discharge, and operational constraints (e.g., partial charge strategies)

5. **Output**
    - **Discharge/Charge Profiles**: Hourly modeling of how the battery is utilized
    - **Cost Savings**: Reduction in energy and demand charges or avoided grid cost
    - **Backup Duration**: If sized for resilience, the total hours/days of critical load coverage

Assumptions

AECOM collected facility data through a request for information process. Energy consumption factors and facility characteristics were identified and integrated in analysis. AECOM used these combined datasets to confirm energy utility consumption baselines.

In performing the analysis, AECOM made the following assumptions:

- This report refers to the City Hall, located at 31516 Railroad Canyon Road, Canyon Lake, CA 92587.
- The monthly and annual electricity consumption is determined using load profile data in the client-provided file "SCE_Usage_8004916079_11-13-24_to_11-13-25." This file contains 35040 load profile data points, which are then consolidated into an 8760 load profile dataset.
- AECOM utilized the Levelized Cost of Energy (LCOE) for the installed cost per watt of PV installations and BESS, as sourced from the National Laboratory of the Rockies (NLR). This data was used to estimate the hypothetical cost of installing the PV array and BESS at the site, as detailed in this report. For an accurate cost estimation, it is necessary to obtain vendor quotes, which are subject to change due to market-dependent time windows. These quotations are typically conducted during the 60% design phase, at which point there is an understanding of the specific equipment ratings and brands to be used.
- This report evaluates the site's existing electrical infrastructure using customer-provided data on the main breaker and bus capacity, as documented in the client-provided file "Canyon Lake Council Chamber-Line Diagram." AECOM has assessed whether the existing electrical system can support the proposed PV array and BESS installation. However, as this is a feasibility study, an on-site assessment is required for a definitive determination. A site visit should be conducted during the advanced design phase, typically at the 30% design stage, to confirm site-specific conditions.
- AECOM has estimated the potential PV generation capacity based on the client-identified available area, as documented in the client-provided file "Solar PV Areas_Canyon Lake." However, a site assessment is required in later project phases, typically at the 30% design stage, to ensure that the site has the necessary infrastructure for PV array installation. This includes evaluating civil structures, load-bearing capacity, particularly for rooftop installations, and other critical conditions necessary for successful implementation.
- This report uses a regionalized estimate of general production (kWh) to calculate the amount of greenhouse gas emissions avoided through PV generation. The calculation is based on the U.S. EPA Emissions & Generation Resource Integrated Database (eGRID).
- This report clarifies that other charges such as connection fees, required service charges, and taxes remain unchanged. The analysis focuses solely on the bill components directly affected by the installation of PV and BESS under the NEM 3 framework.

AECOM utilized the following tools in conducting the analysis:

- AECOM Internal Tools: Proprietary tools developed by AECOM for analyzing energy patterns and evaluating system performance in simulated environments. These tools are designed to assess energy costs for applications such as peak shaving, energy trading, etc. in DER implementations.
- HelioScope: Web-based software tool used for the design and performance analysis of photovoltaic systems. It combines system layout design with energy simulation, allowing users to model rooftop, ground-mounted, and canopy PV installations. The software factors in module placement, tilt, azimuth, shading, and local weather data to provide accurate estimates of system capacity and expected energy generation.

Site Information

This study is conducted for the City Hall, located in Canyon Lake, California, at 31516 Railroad Canyon Rd, Canyon Lake, CA 92587 currently consumes about **53,586 kilowatt-hours (kWh) of electricity per year**,

In terms of electrical infrastructure, the Council Chambers Public Side is served through a main overcurrent device rated 600 amperes (A) with a 400 A sub-feed section supplying a 200 A Panel A. Standby power is provided by a 100 kW generator connected through a 400 A disconnect and a 400 A automatic transfer switch, which then feeds the backed-up distribution via the main breaker and the 400 A sub section. Panel A (200 A) supplies at least two identified branch circuits, including Lighting Circuit #31 and Outlet Circuit #26, which are shown as part of the backed-up distribution path. The one-line provided does not indicate system voltage, short-circuit interrupting ratings, conductor sizes, grounding details, or total connected kilovolt-amperes (kVA).



Figure 1. Site Location

The City indicated that PV was not viable on the west side of the building. WRCOG noted that PV arrays within the green boxes denoted in Figure 2 were to be assumed viable.

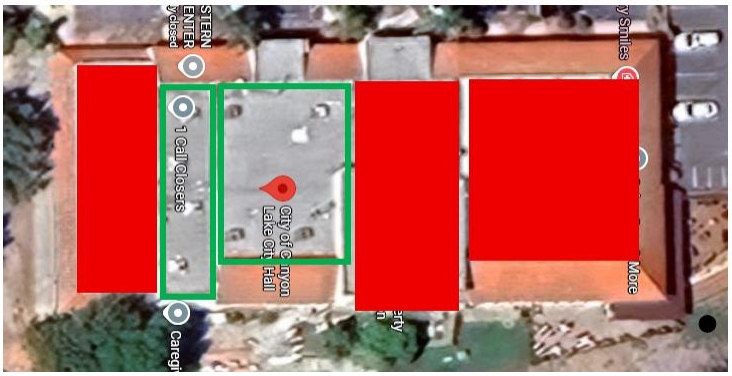


Figure 2. No-Go Areas for PV

Incentive Programs

AECOM has identified three key incentive programs that could benefit the subject site, focusing on renewable energy production and advanced energy storage systems.

The Investment Tax Credit (ITC) and Production Tax Credit (PTC) are federal incentives that reduce the cost of renewable energy projects. ITC offers a tax credit based on a percentage of upfront investment costs, while PTC provides a per-kilowatt-hour credit for electricity generated over time.

Production Tax Credit

Under this initiative, the project is eligible for a tax credit ranging from 0.3 cents to 1.5 cents per installed kWh. The specific value of the credit is determined by several factors, including the project's adherence to certain requirements such as complying with labor standards and using domestic materials.

The PTC program pays for each kilowatt-hour produced over a 10-year period, with government entities receiving the benefit as direct pay instead of a tax credit. For this project, with an estimated 53,586 kWh per year, the best case at 1.5 ¢/kWh would yield about $804 annually, totaling around $8,040 over 10 years.

Investment Tax Credit

The City can take advantage of either the ITC or the PTC, but both cannot be utilized simultaneously. Since construction has not yet commenced, selecting the ITC is the most advantageous option. Under this scenario, the project is limited to the base 30 percent credit because it does not meet any conditions for additional bonus allocations.

The ITC provides an extra 10 percent credit for projects located in federally designated low-income communities. However, according to the 2016–2020 census tract classification shown in Figure 3, the project site is located outside the eligible low-income area. As a result, the project does not qualify for the additional 10 percent bonus and remains capped at the standard 30 percent ITC.

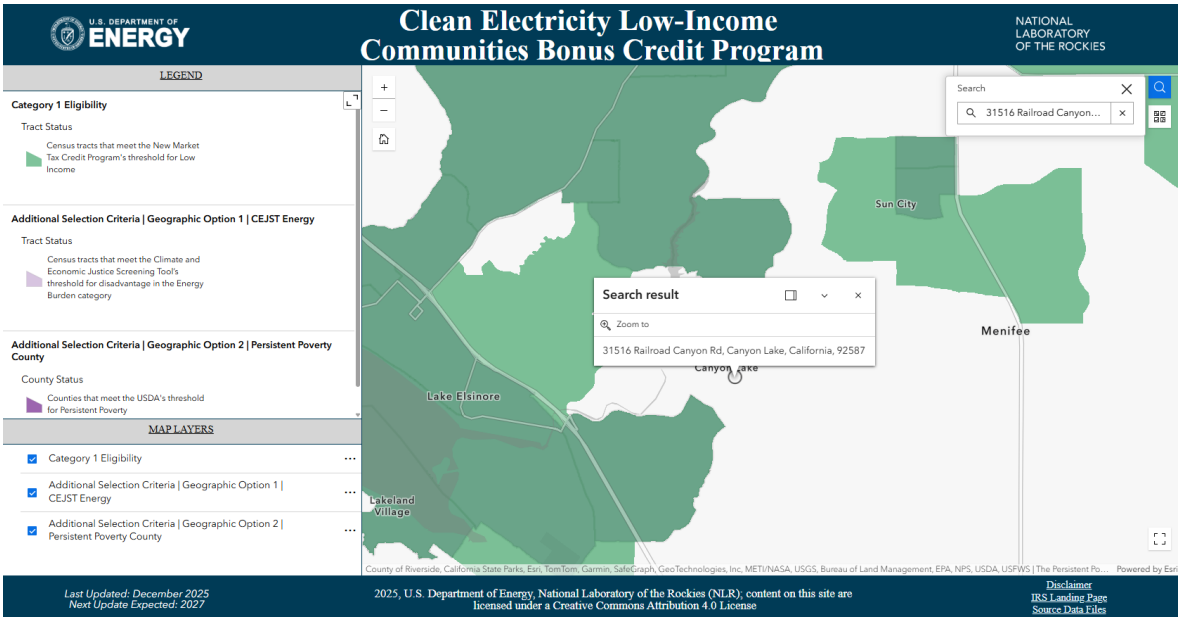


Figure 3. Clean Electricity Low-Income Communities Bonus Credit Program Map

NLR estimates capital expenditure (CAPEX) for commercial PV at $1.75–2.00 /W direct current (DC). For this study, a 28 kW DC PV system is projected. Based on these CAPEX values, total installation cost ranges from $49,000 to $56,000. With the standard 30 percent ITC, the direct-pay benefit for the City would fall between $14,700 and $16,800.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) is California's primary incentive designed to reduce the upfront cost of energy storage systems. The program has three levels:

- **General Market**: For projects located outside Disadvantaged Communities (DAC). Typical incentive: $0.10/Wh.
- **Equity (DAC):** For projects located within a DAC. Incentive: $0.85/Wh.
- **Equity Resilience**: For critical facilities within a DAC and in PSPS or high fire-risk zones. Incentive: $1.00/Wh.

In Case 1, the project site is outside a DAC, so it only qualifies for the General Market level. Using an NLR-based cost of $450/kWh, a 60-kWh battery would cost approximately $27,000. With the General Market incentive of $0.10 /Wh, the project would receive about $6,000, resulting in a net battery cost of roughly $21,000.

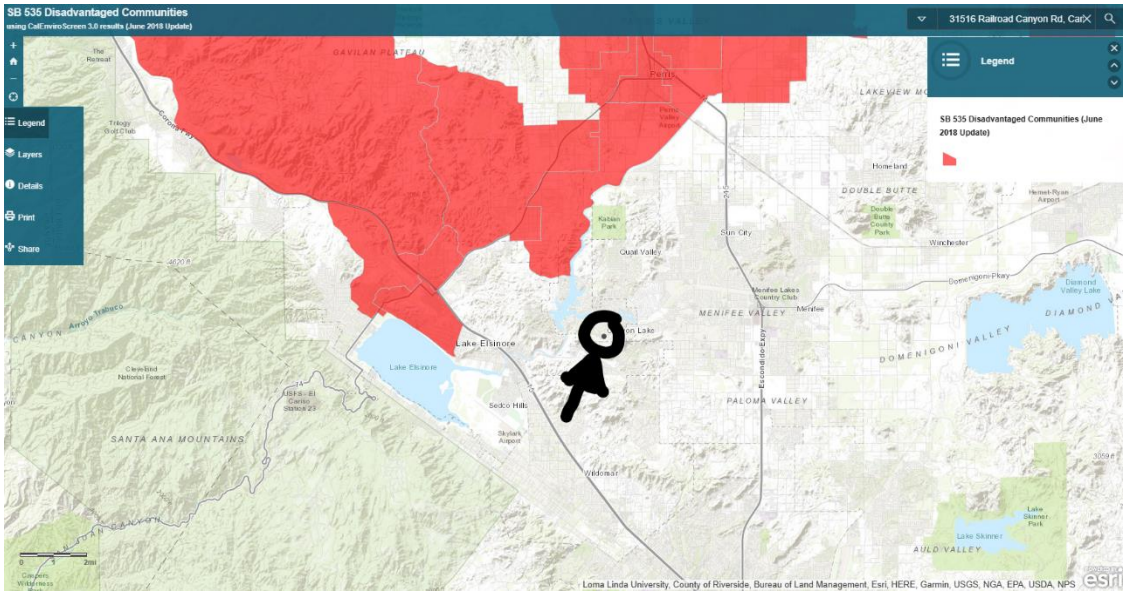


Figure 4. SB 535 Disadvantaged Communities Map

Scenarios & Analysis

Case 0: Current Situation (Baseline)

Tariff & Contract Type

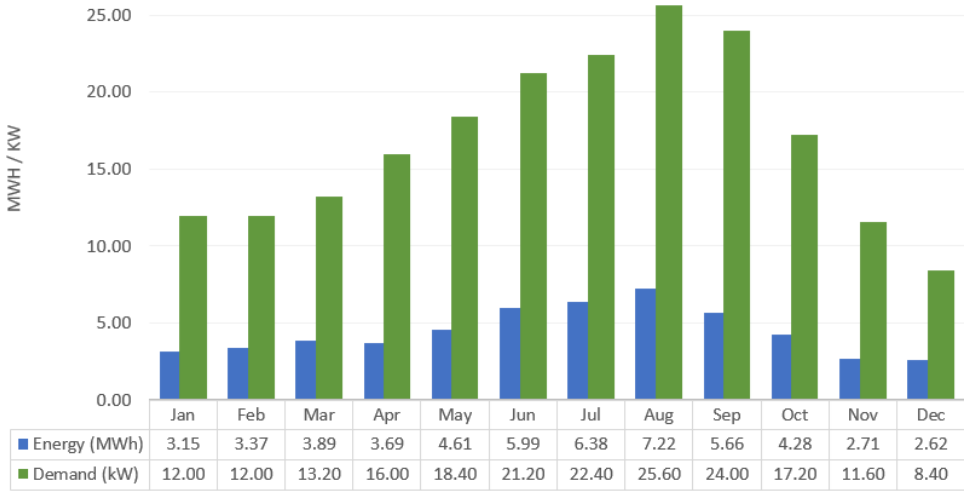
The site is currently served by Sothern California Edison under the TOU-GS-2-D tariff, which is designed for small to medium commercial customers. This rate structure separates costs into energy charges (based on kilowatt-hours consumed) and demand charges (based on the highest kilowatt demand registered during the billing cycle). In addition, prices vary by time-of-use periods—on-peak, mid-peak, and off-peak—so the timing of energy use significantly affects overall costs.

Being on this tariff means the site's operating expenses are directly tied not only to how much energy is consumed but also to when it is consumed and how high the peak demand reaches.

The tariff cost presents the costs as totals (delivery + bundle). The prices were used as the basis for this study. While they may fluctuate slightly month to month depending on market conditions, these variations are generally minor.

Monthly & Annual Energy Consumption and Demand

The facility currently consumes 53,586 kWh annually, with August being the highest month at about 7,220 kWh and November the lowest at about 2,710 kWh. In terms of demand, August records the peak at around 25.6 kW, while December is the lowest at about 8.4 kW. The following graph presents this historical data for the 2024–2025 period.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Energy (MWh)	3.15	3.37	3.89	3.69	4.61	5.99	6.38	7.22	5.66	4.28	2.71	2.62
Demand (kW)	12.00	12.00	13.20	16.00	18.40	21.20	22.40	25.60	24.00	17.20	11.60	8.40

Figure 5. Historic Site Energy Profile

Monthly & Annual Energy Costs

The site currently spends about $21,594 per year in energy and demand cost, with approximately $15,512 in energy costs and $8,728 in demand charges, based on tariff TOU-GS-2-D simulation. For this analysis, we are focusing only on energy and demand costs, as these are the components directly impacted by the installation of a PV system.

Case 1: PV Only

Installed Capacity & Location

The PV system for the site was sized to offset approximately 95% of current consumption. The placement areas for the PV installation were identified according to customer requirements. The system capacity is estimated at 28.2 kW direct current (DC), with an expected annual production of about 51,199 kWh.

Figure 6 presented the modeled energy production throughout the year, and Figure 7 identifies the modeled PV installation areas on the site.

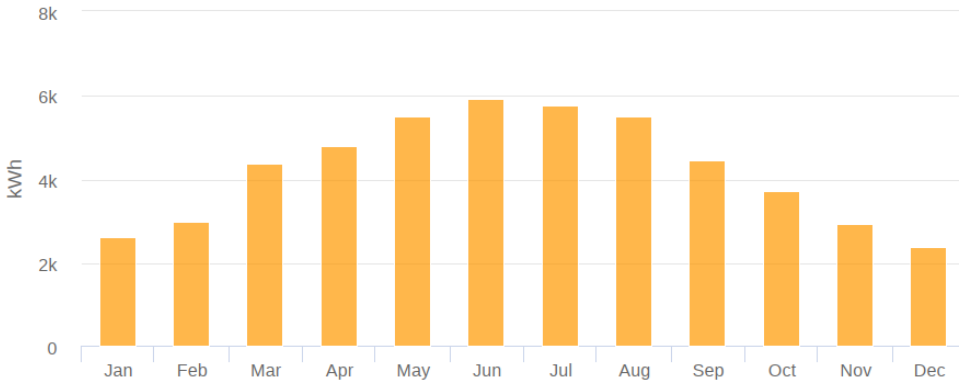


Figure 6. Modeled PV Production



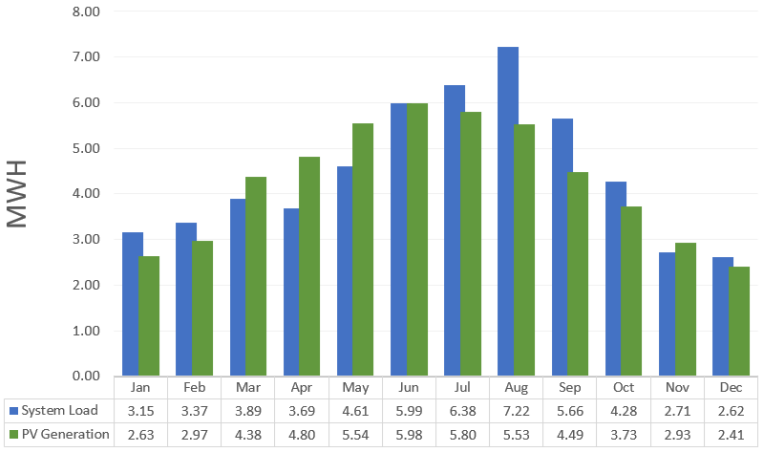
Figure 7. Modeled PV Installation Areas

Modeled PV Production

The modeled PV system is projected to generate an average of **4,266 kWh per month**, with an estimated **annual production of 51,199 kWh**.

This scenario doesn't include a BESS, so the excess energy produced need be exported to the utility, which requires entering a Net Energy Metering (NEM) contract with the utility service provider. Under the currently available NEM tariff, NEM 3.0, exported electricity is credited at dynamic rates that vary by month, hour of day, and weekday, ranging from as low as $0.01/kWh during midday hours to over $1.00/kWh during peak evening hours in high-demand months like August and September. This study has calculated projected benefits from this arrangement.

Figure 8 compares historic monthly energy consumption and modeled PV generation. Not all solar energy will be consumed on-site, as excess daytime production may exceed demand and be exported to the grid, while nighttime demand cannot be covered since there is no generation after sunset and no battery to store the excess in this scenario.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
System Load	3.15	3.37	3.89	3.69	4.61	5.99	6.38	7.22	5.66	4.28	2.71	2.62
PV Generation	2.63	2.97	4.38	4.80	5.54	5.98	5.80	5.53	4.49	3.73	2.93	2.41

Figure 8. Modeled PV Output vs. Site Demand

Capital Expenditures

Based on NLR benchmark CAPEX values for commercial rooftop PV, the estimated cost to install a 28.2 kW DC PV system in Riverside County, California falls in the range of $1.75 to $2.00 per watt DC. This translates to a total investment of **approximately $49,350 – 56,400 for the complete system**.

These figures include typical equipment, installation, and soft costs, reflecting average market conditions for commercial-scale projects. Actual costs may vary slightly depending on site-specific conditions such as roof structure, permitting, interconnection requirements, and labor. However, the NLR benchmarks provide a reliable basis for estimating the capital cost of a system of this size and type in the region.

Operating Expenses

According to NLR's 2024 benchmark data, the annual operations and maintenance (OPEX) cost for commercial rooftop PV systems is about $19 per kW-DC. For a 28.2 kW DC system, this translates to an **estimated yearly OPEX of roughly $536** covering routine maintenance, monitoring, and related operational expenses.

Economic Metrics

The analysis shows that installing a PV system at the site under NEM3 provides measurable financial benefits by offsetting both energy and demand charges. Without solar, the facility currently spends about $21,594 annually on utility costs. With the PV system in operation, the energy cost is reduced to approximately $8,849 per year, while the demand cost drops to about $4,341 per year. In addition, the system generates excess electricity during the day that cannot be fully consumed on-site. Under NEM3 rules, this **exported energy represents an additional benefit of roughly $777 annually**.

Taken together, these reductions and export credits reduce the facility's total utility bill down to **$12,413 per year**, achieving an **overall savings of about 43%** compared to current expenses.

Payback Period and Return on Investment

The financial analysis shows that without PV, the facility spends approximately $21,594 per year on utility costs. With a 28.2 kW DC PV system installed, the annual cost is reduced to about $12,413, resulting in yearly savings of roughly $9,181. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system is estimated at $56,400, but with the 30 percent ITC direct pay, the net investment is reduced to approximately $39,480. In addition, the system carries an annual OPEX of $536, which slightly offsets the yearly savings. Taking these factors into account, the project generates a net benefit of about $9,181 minus $536 per year after OPEX. This results in a simple payback period of approximately 1 year, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross Savings ($)	Net Savings after OPEX ($)	Cumulative Cash Flow ($)
1	9,180	8,644	-30,836
2	9,456	8,904	-21,932
3	9,740	9,171	-12,761
4	10,032	9,446	-3,315
5	10,333	9,729	6,415
6	10,643	10,021	16,436
7	10,962	10,322	26,758
8	11,291	10,632	37,390
9	11,630	10,951	48,340
10	11,978	11,279	59,619
15	13,886	13,076	121,298
20	16,098	15,158	192,801

Table 1. Return on Investment w/ 3% Inflation: Case 1

Technical Feasibility

The Council Chambers Public Side electrical distribution is served through a 600 A main breaker with downstream equipment that includes a 400 A disconnect, a 400 A transfer switch, and a 400 A sub-main section that supplies Panel A rated 200 A.

The proposed PV system has a nameplate capacity of 22.8 kW. At 208 V, 3-phase, the PV inverter full-load output current is 63.3 A (I = 22,800 W ÷ [1.732 × 208 V]). The required PV backfeed breaker rating is 80 A minimum based on 125% continuous current (63.3 A × 1.25 = 79.1 A).

Per NEC 705 120% bus backfeed limitation, the maximum allowable backfeed at a 600 A bus with a 600 A main breaker is 120 A (1.20 × 600 A − 600 A = 120 A). The required 80 A PV breaker is compliant with this limit, and no ampere shortfall exists (120 A allowable − 80 A required = 40 A margin).

Interconnect the PV system using a dedicated 80 A backfed breaker located at the opposite end of the 600 A bus from the 600 A main breaker, with all required NEC 705 source identification, directory, and warning labels applied at the service/distribution equipment and transfer equipment. If the 600 A section bus rating is less than 600 A, or if the main is reduced below 600 A, the interconnection must be revised to a supply-side connection or the bus/main must be upgraded to maintain NEC 705 compliance.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 51,199 kWh per year. Using the U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:"

- Carbon dioxide (CO_2): 21,933.652 pounds (lbs) (9.949 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 22,015.570 lbs (9.986 metric tons) avoided annually
- Nitrogen oxides (NO_x): 16.998 lbs (7.710 kg) avoided annually
- Sulfur dioxide (SO_2): 1.024 lbs (0.464 kg) avoided annually

Case 2: PV + BESS

System Components

This scenario assumes the same PV array described in Case 1 and a BESS sized for surplus PV production. The day with the highest energy surplus in our simulation occurred on May 18, during which the PV system produced 202.9 kWh, the site consumed 87.6 kWh, and the resulting surplus was 115.327 kWh. For size the BESS, we ran several iterations based on the available surplus energy and applied an algorithm that simulates the charge and discharge cycles of one year. This techno-financial analysis indicates that the optimal BESS capacity is approximately 60 kWh.

This simulation factor ensures that even under variations in production or demand, all possible excess solar energy generated during the day can be stored. The stored energy is then available for use at night or during periods when PV production does not fully cover the site's demand.

By doing so, most of the units of solar energy produced on-site are consumed daily by the facility, preventing as little as possible any export to the grid.

Modeled Energy Flows

By installing a 60 kWh battery, we ensure that all the energy generated on-site is consumed by the facility itself. The charge and discharge profile of the battery is designed so that any PV surplus during the day is immediately stored in the battery rather than exported to the grid. Later, if the site demand exceeds the PV generation while there is still energy stored in the battery, the deficit is supplied from the battery.

This operational strategy minimizes or even eliminates consumption from the utility, since the PV and battery combination is prioritized to cover the load at all times. On an annual basis, the system is expected to produce slightly more energy than the site requires, leaving a surplus of around 10%, but this excess is negligible in terms of the overall utility bill.

Capital Expenditures

According to NLR benchmark data, the capital expenditure (CAPEX) for a commercial-scale 22.8kW DC rooftop PV system in Riverside, California is estimated at $39,480 under ITC incentive, based on installation costs of $1.75–2.00 per watt DC.

For storage, NLR's 2025 cost projections indicate a CAPEX of $450 per kWh for the high-cost scenario. Applying this benchmark to a commercial-scale 60 kWh battery system represents an investment of **roughly $27,000** and under the SGIP program this amount can be covered, effectively funding 20% of the BESS system.

Together, the combined **CAPEX for the PV and BESS under ITC and SGIP** programs is **estimated at $54,840** representing the expected upfront investment for a commercial solar-plus-storage project of this size.

Operating Expenses

According to NLR benchmark data, the annual operations and maintenance (OPEX) cost for a commercial-scale 28.2 kW DC rooftop PV system is estimated at $536.

NLR data indicates an operating cost of approximately $4 per kW-year. For a commercial-scale 60 kWh battery system, this results in an annual OPEX of about $240.

Together, the **combined OPEX for the PV and BESS systems is approximately $776 per year**, covering routine maintenance, monitoring, and system management.

Economic Metrics

The analysis shows that installing a commercial-scale PV system paired with a 60 kWh battery under NEM 3 provides strong financial advantages by allowing a substantial portion of the solar energy produced by the PV system to be consumed on-site.

In several cases, PV production exceeds the facility's demand, and the surplus can be stored in the BESS for later use. However, without a battery system, the facility cannot absorb all of this excess energy, since any unused

generation must be consumed the moment it is produced. This unused energy would otherwise need to be exported to the utility grid, where under current NEM rules it would be compensated at only about 25 percent of the retail electricity rate. Given that time-of-use pricing makes stored energy far more valuable during high-cost periods, it becomes financially preferable to store surplus solar rather than sell it.

Without a BESS, exporting this excess would generate $777 but the facility would still face an annual utility cost of $12,413. By contrast, installing the BESS reduces grid reliance and allows the facility to consume nearly all of its solar production during higher-priced periods, resulting in a significantly lower annual utility bill of $6,304.

To remain conservative, this analysis assumes that 10% of annual energy costs remain due to efficiency losses, imperfect alignment of PV output and site load, and seasonal variability.

It is important to note that other charges — such as connection fees, requisite charges, and taxes — remain unaffected. This analysis focuses only on those bill components directly impacted by the installation of PV and BESS under the NEM 3 framework.

Payback Period and Return on Investment

The financial analysis shows that without PV + BESS, the facility spends approximately $21,594 per year on utility costs. With a 28.2 kW DC PV system and 60 kWh BESS system installed, the annual cost is reduced to about $ 3,933 resulting in yearly savings of roughly $17,661. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system under ITC and SGIP incentives is estimated at $54,840. In addition, the system carries an annual OPEX of $ 776 Taking these factors into account, the combined system generates a net benefit of about 16,885 per year after OPEX. This results in a simple payback period of approximately 4 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross-Savings ($)	Net-Savings after OPEX ($)	Cumulative Cash Flow ($)
1	17,661	16,885	-43,595
2	18,190	17,391	-26,204
3	18,736	17,913	-8,291
4	19,298	18,450	10,159
5	19,877	19,004	29,163
6	20,473	19,574	48,737
7	21,088	20,161	68,898
8	21,720	20,766	89,664
9	22,372	21,389	111,053
10	23,043	22,031	133,083
15	26,713	25,539	253,555
20	30,968	29,607	393,216

Table 2. Return on Investment w/ 3% Inflation: Case 2

Technical Feasibility

The Council Chambers Public Side electrical system on the public side includes a 400 A disconnect, a 400 A transfer switch, a 600 A main breaker, and a 400 A sub main panel feeding Panel A (200 A) and branch circuits including a 200 A lighting circuit (#31) and an outlet circuit (#26).

To interconnect an additional 25 kW AC PV system and a 60 kWh BESS, the preferred point of interconnection is at the 400 A sub main panel, provided the panel bus rating, existing feeder arrangement, and available breaker spaces support the added backfeed and the connection complies with NEC interconnection limits.

A load side connection at the 400 A sub main panel requires verification of the applicable NEC 705 bus and backfeed constraints using the actual panel bus rating, main device rating, and the proposed PV inverter output breaker and BESS PCS breaker ratings. If the 120% bus limitation cannot be met, a line side (supply side) connection ahead of the 400 A sub main panel, coordinated with the 600 A main section, should be evaluated to remove the PV and BESS contribution from the load side bus limitation.

Because a 400 A transfer switch is present, the interconnection must be arranged so that PV and BESS operation does not unintentionally backfeed through the transfer switch or energize sources in a manner that defeats the transfer equipment purpose. The transfer switch wiring method, source side isolation, and operating modes must be reviewed to confirm normal source versus alternate source behavior and acceptable DER interaction.

New overcurrent protection and disconnecting means will be required for both systems at the point of connection, including a PV AC output breaker and a BESS breaker sized to the selected inverter and PCS ratings. Conductor and grounding updates must be provided from each new device to the interconnection point, with routing and terminations compatible with the 400 A equipment ratings.

A protection and coordination review is required to confirm interrupting ratings, breaker coordination between the 600 A main, the 400 A sub main equipment, and the new PV and BESS protective devices, and to confirm labeling, lockable disconnect requirements, and utility metering or inspection requirements at the selected interconnection location.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 51,199 kWh per year. Using the U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:"

- Carbon dioxide (CO_2): 21,933.652 lbs (9.949 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 22,015.570 lbs (9.986 metric tons) avoided annually
- Nitrogen oxides (NO_x): 16.998 lbs (7.710 kg) avoided annually
- Sulfur dioxide (SO_2): 1.024 lbs (0.464 kg) avoided annually

CASE 3: BESS Only

Critical Load Identification

Based on the facility classification as an office hub, the applicable emergency and legally required standby systems are limited to life-safety and code-mandated functions. Under NEC 700 and NFPA 72, emergency power is required for fire alarm control equipment, emergency egress lighting, and associated branch circuits serving exit pathways. NEC 701 applies to legally required standby systems that support orderly shutdown and limited continuity functions, such as select lighting and receptacle circuits serving safety-related areas. No mission-critical or process loads are mandated for this facility type. Based on these requirements, the critical load is estimated at 7.5 kW, representing approximately 25 percent of the total connected load.

Battery Capacity & Infrastructure

In this scenario, based on the evaluation of critical loads, we recommend a battery energy storage system with 30 kWh usable capacity and 5 kW continuous power. At the identified load of 7.5 kW, this system provides **approximately 4 hours of backup**, exceeding both the 2-hour minimum of NFPA 110.

Capital Expenditures

Using cost benchmarks published by the National Laboratory of the Rockies (NLR), the estimated **capital cost** (CAPEX) for a 30 kWh / 20 kW battery energy storage system is approximately **$13,500**. This figure includes the battery cabinets, inverter/PCS, microgrid controller with ATS, installation, protections, and engineering.

Operating Expenses

The expected **OPEX** is about **$120 per year**, also based on NLR reference values. This covers preventive maintenance, monitoring software, and NFPA 110 testing requirements. Battery replacement is typically required after 10–12 years of service.

Return on Investment & Qualitative Benefits

While a conventional financial return ROI cannot be directly applied to this case, the value of a BESS for a fire station is usually framed in terms of resilience, reliability, and compliance. Such systems are designed to ensure uninterrupted operation of life-safety and mission-critical equipment, including fire alarms, communications, lighting, and fuel dispensing, during extended utility outages. The benefits include maintaining service continuity, safeguarding firefighter readiness, and protecting the surrounding community. Compliance with NFPA 110, NFPA 70, and NFPA 72 also reduces liability exposure and ensures that the facility meets recognized safety standards.

However, for this particular site, the installation of a battery energy storage system does not present a compelling case. The facility already operates with a 100 kW emergency generator, which is more than sufficient to sustain the identified critical load of approximately 75 kW. Given this existing capacity, the addition of a 30 kWh / 20 kW BESS as a resilience measure would provide little to no incremental benefit relative to cost. The generator fully covers the resilience requirement, and therefore the justification for a BESS here would not be technical necessity

Technical Considerations

Key technical considerations include verification of available bus capacity for interconnection, compliance with the 120 percent load-side rule where applicable, and confirmation that breaker and feeder ratings are adequate for the added source. The emergency transfer scheme must maintain strict separation between normal and emergency circuits, with coordinated transfer sequencing. A short-circuit and protective device coordination study is required to validate fault duties after interconnection. Final design must also address battery system safety, including listing compliance and UL 9540A evaluation as required by the authority having jurisdiction.

Decision Matrix and Scenario Comparison

In order to determine the most appropriate scenario for the site, four scenarios were developed and analyzed: business as usual (Case 0), installing a PV system only (Case 1), installing PV with a BESS (Case 2), and installing a BESS only (Case 3). Each case was evaluated in terms of resilience value, capital and operating expenditures, energy savings, payback period, and technical feasibility. The decision matrix summarizes the comparative performance of these options.

Criteria	Case 0: Baseline	Case 1: PV Only	Case 2: PV + BESS	Case 3: BESS Only
Resilience Benefit	None	Limited (daytime only)	Moderate (self-consumption, some coverage)	High (but redundant due to existing 100 kW generator)
CAPEX ($)	0	~$49k–$56k (≈$39k net with ITC)	~$54.8k (PV + BESS after ITC and SGIP)	~$13.5k (~10.5k under SGIP)
OPEX ($/yr)	Current	~$536	~$776	~$120
Annual Utility Bill ($)	~$21,594	~$12,413	~$3,933	~$21,594 (no reduction)
Annual Savings ($)	–	~$9,181	~$17,661	Minimal (non-financial)
Payback Period	–	~4-5 years	~4 years	No ROI
GHG Reduction	None	~10 $MTCO_2e$ avoided annually	Same as Case 1	None
Technical Feasibility	Already in place	NEC 705 compliant via 80 A backfed breaker at 600 A bus	Requires PV + BESS integration and transfer switch coordination	Technically feasible but unnecessary due to generator capacity

Table 3. Scenario Comparison

Conclusion

Based on the comparative analysis, **Case 2 (PV + BESS)** emerges as the preferred scenario for the site. While Case 1 (PV-only) provides meaningful cost savings and emission reductions, the addition of a battery system in Case 2 significantly enhances overall project value by accelerating payback, increasing on-site energy utilization, and introducing a measurable level of resilience. Compared to the baseline, Case 2 achieves the highest annual savings and the lowest remaining utility costs, resulting in a faster recovery of capital investment.

Although the facility already has a 100 kW emergency generator, the BESS in Case 2 provides complementary resilience by enabling short-duration, seamless load support, improving operational continuity during grid disturbances, and reducing reliance on fuel-based backup during minor outages or transition events. Case 3 (BESS-only) was not selected because it does not generate operational savings and provides limited incremental benefit beyond the existing generator.

Therefore, Case 2 represents the best balance between economic performance, resilience enhancement, and environmental impact. It delivers the shortest payback period among all evaluated scenarios, materially reduces the facility's energy footprint, and leverages available incentives to maximize return while maintaining technical feasibility within the existing electrical infrastructure.

Summary of Strategy & Benefits

The selected strategy focuses on installing a rooftop PV system combined with a right-sized BESS, designed to maximize on-site consumption of solar energy while minimizing grid dependency. This approach achieves the following benefits:

- **Resilience**: Provides limited but meaningful backup capability, enabling short-duration load support and smoother transitions during grid outages, complementing the existing generator.
- **Economic Savings**: Reduces annual utility costs from approximately $21,594 to about $3,933, resulting in annual savings of roughly $17,661.
- **Financial Feasibility**: Delivers a simple payback period of approximately 4 years, faster than the PV-only scenario, with long-term savings protected against future energy price escalation.
- **Environmental Impact**: Offsets approximately 10 metric tons of CO_2e emissions annually, significantly reducing the site's operational carbon footprint.
- **Technical Practicality**: Integrates within the existing electrical system with manageable interconnection upgrades, while maintaining compliance with NEC interconnection and protection requirements.
- **Operational Efficiency**: Maximizes self-consumption of PV generation, minimizes energy exports under NEM 3.0, and reduces reliance on fuel-based generation for non-critical events.

Next Steps

To advance the project, the following steps are recommended:

1. **Detailed Design & Site Assessment:** Conduct a 30% design phase evaluation, including structural assessment of the roof, electrical interconnection details, and shading analysis
2. **Vendor Quotations:** Obtain updated vendor quotes for PV system equipment, installation, and interconnection to refine cost estimates beyond NLR benchmarks
3. **Permitting & Interconnection:** Coordinate with Southern California Edison (SCE) to complete the interconnection study and ensure compliance with NEM 3 tariff rules
4. **Finalize Incentive Applications:** Submit applications for the 30% ITC (direct pay) to secure federal funding and reduce upfront capital cost
5. **Procurement & Installation:** Issue RFPs for procurement and construction, selecting qualified contractors with experience in municipal PV installations
6. **Commissioning & Monitoring:** Upon installation, perform commissioning tests, integrate the system with monitoring platforms, and establish an operations and maintenance (O&M) plan to ensure reliable long-term performance

Appendix

Incentive Programs

This section outlines how the incentive programs function and provides relevant information about them. Specific application of these programs to presented scenarios is explored in previous sections.

Inflation Reduction Act

The Inflation Reduction Act of 2022 stands as a significant piece of legislation designed to strengthen the United States' commitment to fighting climate change by making considerable investments in renewable energy. A key feature of the Inflation Reduction Act is its financial incentives, namely the Investment Tax Credit (ITC) and the Production Tax Credit (PTC), which aim to accelerate the adoption of renewable energy technologies.

The ITC allows for a significant tax credit for investments in renewable energy technologies, including solar panels and wind turbines, directly reducing the upfront cost of these systems. This makes renewable projects more financially viable and attractive to investors and consumers alike. On the other hand, the PTC provides a per-kilowatt-hour tax relief for the production of energy from renewable sources, incentivizing the operation and expansion of renewable energy facilities.

Notably, Inflation Reduction Act programs have been subject to change in recent legislation. Presented here are active opportunities as of the time of the report.

Production Tax Credit

The Production Tax Credit (PTC) within the framework of the Inflation Reduction Act offers considerable financial incentives for renewable energy projects, primarily designed to decrease the federal income tax liability based on the electricity produced per kilowatt-hour.

The PTC directly reduces the federal income tax for taxable entities. Furthermore, for non-taxable entities such as local governments, educational institutions, or nonprofit organizations, the PTC allows these credits to be monetized, facilitating their involvement in renewable energy initiatives. This provision is applicable for projects that become operational between January 1, 2023, and December 31, 2032, providing a broad window for planning and implementation.

Projects located in designated low-income energy communities receive further incentives. The PTC is structured to be claimable annually for a decade from the start date of operations of the qualifying renewable system, providing long-term financial support. This current structure of the PTC is set to continue through the end of 2024. Starting from January 1, 2025, the credit system will transition to a technology-neutral format, broadening the scope to include a wider array of technologies and fostering a more inclusive approach to renewable energy incentives.

As of the date of this report, the program is still active but solar projects must have “begun construction” by July 4, 2026.

The City Site project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

Investment Tax Credit

The Investment Tax Credit (ITC) established under the Inflation Reduction Act offers a powerful incentive for deploying renewable energy technologies by providing a reduction in federal tax liability. This reduction is calculated as a percentage of the capital investment made in eligible energy systems. Taxpayers can apply the ITC to their federal income tax for the year the technology is installed, significantly decreasing their tax burden.

Starting January 1, 2023, special provisions enable tax-exempt entities such as local governments and nonprofits to receive direct payments equivalent to the value of the credit. This arrangement improves the liquidity and financial

feasibility of renewable projects for these organizations. The scope of eligible technologies under the ITC is broad, encompassing solar panels, wind turbines, fuel cells, and other renewable energy systems.

As of 2025, the Investment Tax Credit (ITC) for solar projects is set at 30% of the eligible costs, encompassing both the equipment and installation expenses. This rate is scheduled to decrease to 26% in 2033 and further to 22% in 2034. Systems rated under 1 megawatt (MW) qualify for the full 30% without having to comply with additional requirements; larger systems will only receive the full amount if they meet specific labor requirements. These include paying prevailing wages to workers during construction and using apprentices to perform a portion of the total construction hours (15% after 2023). Bonus credits are available based on site location, e.g. low-income communities.

The ITC is set to continue delivering these benefits at its current rate until 2032, contingent upon meeting the specific project criteria laid out in the act. Looking ahead, post-2024, the ITC will transition to a technology-neutral system, which will be applicable to all zero-emissions technologies, reflecting a shift towards a more inclusive and adaptable approach to supporting renewable energy development.

HHZP project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

As of the date of this report, the program is still active but critical deadlines for project eligibility and complete operability are quickly approaching in 2026 and 2027, respectively.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) offers financial incentives to non-residential customers of utility Company to encourage the adoption of energy storage systems. These systems help businesses prepare for power outages that may occur due to weather, emergencies, or other unforeseen events. The SGIP funding is authorized through 2024, with incentives structured to decrease over time as funding milestones are reached or as more participants enter the program.

Non-residential customers have access to three types of SGIP rebates: General Market, Equity, and Equity Resilience. Furthermore, SGIP incentives are significantly higher for vulnerable or disadvantaged communities through the Equity and Equity Resilience categories.

Incentives are typically paid upfront for residential systems upon project completion and site verification, while nonresidential systems may receive half upfront with the balance paid based on the system’s performance over time. Eligibility for SGIP incentives extends to residential, commercial, industrial, agricultural, and municipal customers of specific utilities including Pacific Gas & Electric, Southern California Edison, SoCalGas, San Diego Gas & Electric, and those managed by the Center for Sustainable Energy.

To be eligible for this rebate, a facility must satisfy two conditions: firstly, it must fall under the category of a government agency, educational institution, non-profit organization, or small business. Secondly, it must fulfill at least one of the following requirements: be located in a Disadvantaged Community (DAC), be situated in a census tract where the Median Household Income of the Statewide Median Income or be situated in California Indian Country.

On the other hand, the equity resilience rebate offers a rate, covering a percentage of the cost of an average energy storage system. To qualify for this rebate, a facility must meet certain requirements. Firstly, it must have experienced two or more utility Public Safety Power Shut-offs (PSPS), or it should be located in a Tier 2 or 3 High Fire Threat District (HFTD) and serve customers in DACs or Low Income Communities. Secondly, it must fulfill at least one of the following additional criteria:

- Be a police station, fire station, emergency response provider, emergency operations center, 911 call center, medical facility, private and public natural gas, electric, water, wastewater, or flood facility, jail or prison, utility-designated PSPS assistance center, cooling center, homeless shelter.
- Be a grocery store, supermarket, or corner store with less than $15 million in annual gross receipts.
- Be an Independent Living Center or a Food Bank.

Modeling Assumptions

The modeling conducted for this feasibility study was based on standard industry benchmarks, available site data, and conservative assumptions to ensure realistic projections. The following key assumptions were applied:

1. **Energy Consumption Baseline** – Historical hourly load data (8,760 points) from the facility was consolidated to represent a typical annual profile. This served as the reference for sizing PV and BESS systems.
2. **PV System Costs** – Capital expenditure (CAPEX) and operations and maintenance (OPEX) values were derived from the National Laboratory of the Rockies (NLR) 2024–2025 benchmarks for commercial rooftop systems. PV CAPEX was assumed at $1.75–$2.00/Wdc, with OPEX at ~$19/kW-year.
3. **BESS Costs** – Battery energy storage CAPEX was modeled using NLR 2025 benchmarks at ~$350/kWh. OPEX was assumed at ~$40/kW-year, covering maintenance, monitoring, and lifecycle management.
4. **ITC Incentives** – A 30% Investment Tax Credit (direct pay) was assumed, reducing upfront project cost. No additional low-income or disadvantaged community adders were included, since the site does not qualify.
5. **Performance Parameters** –
    - PV generation modeled with HelioScope using site tilt, azimuth, and shading factors.
    - Battery modeled with 90% round-trip efficiency and daily cycling where applicable.
    - Energy inflation rate of 3% annually applied to utility costs.
6. **Utility Tariff** – The analysis used the most recent Southern California Edison tariff, **TOU-GS-2 Option D**, as published in the file *ELECTRIC_SCHEDULES_TOU-GS-2_2025*. It was assumed under the current **NEM 3** framework. Exported PV energy was valued at ~25% of retail rate. Since tariff structures and prices are subject to future changes, the financial outcomes presented here should be viewed as indicative estimates rather than fixed projections.
7. **Infrastructure** – Electrical interconnection feasibility was preliminarily evaluated using customer-provided single-line diagrams. Minor breaker adjustment (600 A to 500 A) was assumed to comply with NEC 705.12 120% busbar rule for PV backfeed.
8. **Environmental Impact** – Greenhouse gas (GHG) reduction estimates were calculated using EPA eGRID emission factors for the CAMX subregion, applied to modeled PV generation.

Disclaimer: These figures are rough estimates intended for feasibility-level evaluation. If more precise values are required, additional detail must be developed through site-specific engineering, vendor quotations, and utility coordination during the advanced design phase.

Net Energy Metering

Net Energy Metering (NEM) in California is a billing arrangement that allows residential and commercial customers who generate their own electricity, primarily through solar photovoltaic (PV) systems, to receive credit for the surplus energy they contribute to the grid. This system is designed to incentivize the use of renewable energy sources by offsetting the cost of electricity consumption with the energy produced by these installations.

Under NEM, when a solar system generates more electricity than is consumed, the excess energy is sent back to the utility grid, and the customer earns credits. These credits can then be used to offset the cost of energy drawn from the grid when the solar system isn't producing enough to meet the customer's demand, like during nighttime or cloudy days. The rules, rates, and credits under NEM can vary over time, with different iterations such as NEM 1, 2, and the latest NEM 3, each having specific regulations and compensation structures for solar energy production and exchange.

The transition from NEM 2 to NEM 3 in California, which was effective on April 14, 2023, introduced significant changes in the net metering policies for utility customers with photovoltaic (PV) systems. These changes impact several aspects, particularly the economics of energy arbitrage between PV system owners and the utility. Here's a summary of the key changes:

1) **Reduction in Export Rates:** Under NEM 3, there's a substantial reduction in the rates for excess electricity exported onto the grid by solar systems. This rate has been reduced by approximately 75%, thereby lowering the overall savings for home solar systems and increasing the payback period. This change is a shift from the traditional one-to-one offset of net metering policies, where the price of a kWh of electricity pushed onto the grid was equal to the price of a kWh pulled off the grid.
2) **Implementation of Electrification Rates:** Customers enrolling in NEM 3 are required to use electrification rates instead of regular Time-of-Use (TOU) rates. These electrification rates feature higher on-peak charges and lower off-peak charges, along with a fixed charge of $15 per month. The peak rate period remains from 4 pm to 9 pm.
3) **Export Compensation Based on Avoided Cost Calculator (ACC):** Export compensation under NEM 3 is determined by California's ACC, with specific export rates for every combination of Month, Hour, and Weekday or Weekend. The export value is lowest in the middle of the day when solar energy is abundant on the grid and highest during peak summer demand periods. Notably, the export rates are significantly lower than retail rates during the hours when PV systems are most productive (10 am – 3 pm). To maintain the financial viability of solar PV systems, customers in PG&E and SCE service territories receive an adder on top of the ACC rate, ranging between 2.2 and 9 cents depending on location and customer class.
4) **Shift to a Cost Avoidance System:** NEM 3 introduces a cost avoidance system for exported electricity. This system pays customers the lowest amount a company can pay under the Public Utility Regulatory Policies Act of 1978 (PURPA), which is significantly less than the typical retail rate. This results in customers receiving, on average, 75% less for the electricity they sell back to the grid, with rates varying by month and by hour.
5) **Grandfathering NEM 2 under NEM 3:** Under the recent NEM 3 policy in California, existing customers with a photovoltaic (PV) system installed under NEM 2 can retain the benefits and terms of their NEM 2 agreement, a process known as "grandfathering." However, these customers are restricted from replacing or adding capacity to their PV systems if they wish to maintain their NEM 2 status, as any significant modifications would require transitioning to the terms of NEM 3.

The Net Energy Metering (NEM) 3.0 policy introduces transformative changes, particularly enhancing the value of utilizing Battery Energy Storage Systems (BESS) for owners of solar power systems. A significant aspect of NEM 3.0 is the reduction in compensation rates for surplus electricity fed back into the grid by solar systems, now down to 75%. This adjustment shifts the financial dynamics, making it less lucrative to export excess solar energy to the grid. Instead, storing this surplus energy in a BESS and utilizing it when energy costs are higher becomes a more financially savvy approach.

The utility of BESS extends beyond merely optimizing the use of solar energy. It offers several additional advantages, such as providing backup power during utility blackouts, mitigating charges associated with demand peaks, and enabling energy arbitrage. Energy arbitrage under this system allows for the charging of BESS not only with excess solar energy but also with cheaper grid energy during low-cost periods. This stored energy can then be used in lieu of more expensive grid power at peak times, effectively reducing reliance on utility-supplied energy. Consequently, NEM 3.0 not only promotes more efficient use of solar energy but also broadens the scope of BESS applications, contributing to a more versatile and resilient energy management strategy.

AECOM



Microgrid Feasibility Study
City of Corona

Site:
Corporation Yard

February 2026

Delivering a better world

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Executive Summary

This study appraises the viability and benefits of distributed energy resource implementation scenarios at the subject site. Four scenarios were analyzed, and key metrics are summarized below:

Case	Components	CAPEX ($)	Utility Savings ($/year)	Payback Period (years)	GHG Reduction ($MTCO_2e$/year)
1	PV	~$2.83M under ITC	~42% reduction	~8	~805
2	PV + BESS	~$2.83M (PV) + BESS covered by SGIP	~71% reduction	~6	~805
3	BESS	~$ might be fully covered by SGIP	Minimal (non-financial)	—	None
0	Business-as-usual	—	—	—	None

Note: All values are approximate and subject to final design and incentive approval.

- **Case 1: Photovoltaic (PV) array** – Provides onsite energy generation and offsets a significant portion of annual load. Moderate capital cost after ITC.
- **Case 2: PV + battery energy storage system (BESS)** – Maximizes on-site solar consumption, minimizes grid reliance, yields the highest financial savings, and captures state/federal incentives including ITC and SGIP.
- **Case 3: BESS only** – Provides resilience benefits but offers no utility bill reduction.
- **Case 0: Business-as-usual** – Maintains current utility dependence with no operational or economic improvement.

Considering the above, this study concludes that **Case 2 (PV + BESS)** is the most advantageous and cost-effective scenario. It delivers the highest annual savings (~$584k/yr), the shortest payback period (~6 years), full access to SGIP Equity incentives for a 2,000-kWh BESS, and the strongest resilience performance. This combined strategy enables near-complete energy self-consumption, dramatically reduces exposure to utility rate volatility, and supports long-term operational stability while achieving substantial greenhouse gas reductions.

Recommended Next Steps

1. Advance to a 30% design phase with detailed structural, electrical, and load-flow assessments.
2. Obtain vendor-specific quotations to refine PV and BESS costs beyond benchmark-based assumptions.
3. Initiate permitting and interconnection applications with electric utility under the current NEM 3.0 framework.
4. Secure federal incentives, including the 40% Investment Tax Credit (direct pay), and submit SGIP Equity applications to fully fund the 2,000-kWh BESS.
5. Prepare procurement and construction planning, targeting commissioning within the next major budget cycle.

Background

Purpose

In recent years, especially within the past decade, the impacts of extreme heat and wildfires have been profound through the Inland Empire. Power service disruptions have been increasing in frequency and severity throughout Riverside County, affecting the availability of essential services and community resources.

In 2023, the Western Riverside Council of Governments (WRCOG) received an award (Grant Agreement OPR23145) from the Adaptation Planning Grant Program of the California Governor's Office of Land Use & Climate Innovation Integrated Climate Adaptation and Resilience Program. This program provides funding to help fill local, regional, and tribal planning needs, provides communities the resources to identify climate resilience priorities, and supports the development of a pipeline of climate-resilient infrastructure projects across the state.

As part of this grant-funded project, the Energy Resilience Plan 2.0, WRCOG commissioned microgrid feasibility studies for its member agencies. These studies serve to provide valuation of a potential microgrid at a community-essential facility, as designated by the member agency.

The site selected for this study is the Corporation Yard complex located along Public Safety Way.

This study presents key insights and findings from the evaluation of distributed energy resource (DER) scenarios, including photovoltaic (PV) array and battery energy storage system (BESS) components, at the subject site. It includes analysis of the site's historic energy demand profile and appraises potential PV array and BESS sizing and siting scenarios accordingly. Notably, the study includes assessment of the generation and storage requirements to support the site's critical loads to enable resilience for a specified number of hours during power service disruptions.

Furthermore, this study outlines the financial implications of self-generation, including estimated cost savings, return on investment (ROI), and potential financing options for the project.

It is important to note that this study serves as a preliminary technical and financial assessment. Its purpose is to provide the City of Corona with the information to make an informed decision on whether to proceed to next phases of microgrid implementation before committing to detailed engineering design and further investment.

Adaptation Planning Grant Program

As communities in California experience more frequent, prolonged, and severe impacts from climate change, communities and governments at all scales are developing strategies and implementing actions to build a climate-resilient future. However, many jurisdictions, especially under-resourced communities in California, lack the capacity, tools, guidance, and resources to effectively prepare for climate impacts.

The Adaptation Planning Grant Program addresses this capacity gap by providing funding to help fill planning needs, providing communities with the resources to identify climate resilience priorities, and supporting the development of climate resilience projects across the state. The Adaptation Planning Grant Program enables communities to climate risk and adaptation considerations into planning activities and prepare for climate readiness and resilience in the long term.

The Adaptation Planning Grant is part of the Integrated Climate Adaptation and Resilience Program (ICARP) housed within the Governor's Office of Land Use and Climate Innovation. ICARP advances statewide climate adaptation and resilience by coordinating investments, partnerships, and climate science to ensure people, natural systems, and the built environment are protected, prepared, and thrive in the face of climate change.

Through direct and equity-focused investments and resources, ICARP helps build climate adapted and equitable communities in California, with a focus on solutions that address the impacts of climate change and reduce greenhouse gas emissions. ICARP works to advance these priorities across all levels of government by developing

actionable science and research; providing guidance, tools, and technical assistance; and administering climate resilience-focused grant programs.

Learn more: https://lci.ca.gov/climate/icarp/

Modeling Methodology

This section defines the criteria for sizing the PV array and BESS system components, detailing general parameters, technical requirements, and expected performance criteria.

PV Modeling

1. **Data Inputs**
    - **Solar Resource**: Hourly or sub-hourly irradiance data (e.g., typical meteorological year or on-site measurements)
    - **Site-Specific Factors**: Tilt angle, azimuth, shading analysis, and available roof/ground space
2. **Simulation Approach**
    - Use of HelioScope software to estimate hourly PV production
3. **Sizing Criteria**
    - **Capacity Target**: The sizing criteria are based on 110% of the facility's current annual energy consumption. This approach aims to fully offset the facility's energy usage with the PV array while incorporating an additional 10% capacity to accommodate future demand growth. However, the final system capacity is constrained by the area designated as available by the client.
    - **Performance Ratio**: Evaluate Performance Ratio to ensure consistent system output
    - **Energy Production**: Hourly, daily, monthly, and annual PV generation forecasts
    - **Load Matching**: Amount of PV energy that directly offsets site load vs. excess exported to the grid

BESS Modeling

1. **Data Inputs**
    - **Load Profile**: Detailed electricity consumption and demand patterns
    - **PV Production Profile**: From the PV modeling results
    - **Energy Duration for Resilience**: Determine the critical loads that the BESS will support during islanding operations
2. **Operational Modes**
    - **Energy Shifting / Excess PV Storage**: Battery charges when PV output exceeds site demand, discharges when site demand is high.
    - **Resilience (Standalone BESS)**: Sized to support critical loads during outages
3. **Sizing Criteria**
    - **Capacity (kWh)**: Based on required autonomy (energy shifting, peak shaving, or resilience duration)
    - **Max Discharge/Charge Rate (kW)**: Aligned with site load peaks, PV generation surpluses, and emergency power needs
4. **Simulation Approach**
    - Hourly or sub-hourly dispatch modeling to maximize economic benefit (e.g., demand charge reductions or avoided peak rates)

- Incorporate battery round-trip efficiency, self-discharge, and operational constraints (e.g., partial charge strategies)

5. **Output**

   - **Discharge/Charge Profiles**: Hourly modeling of how the battery is utilized
   - **Cost Savings**: Reduction in energy and demand charges or avoided grid cost
   - **Backup Duration**: If sized for resilience, the total hours/days of critical load coverage

Assumptions

AECOM collected facility data through a request for information process. Energy consumption factors and facility characteristics were identified and integrated in analysis. AECOM used these combined datasets to confirm energy utility consumption baselines.

In performing the analysis, AECOM made the following assumptions:

- This report refers to the City's Corporation Yard complex located along Public Safety Way.
- AECOM was provided energy usage data for two Southern California Edison service meters (359150-000591, V349N-008639). However, it was not denoted which building(s) in the Corporation Yard Complex these meters correspond to. As such, analysis of this study is presented for "Corporation Yard" in lieu of details about which building(s) and organization(s) these meters serve.
- The monthly and annual electricity consumption is determined using load profile data in the client-provided file "Corona _ SCE _ Corp Yard_15min." This file contains 35,040 load profile data points, which are then consolidated into an 8760 load profile dataset.
- AECOM utilized the Levelized Cost of Energy (LCOE) for the installed cost per watt of PV installations and BESS, as sourced from the National Laboratory of the Rockies (NLR). This data was used to estimate the hypothetical cost of installing the PV array and BESS at the site, as detailed in this report. For an accurate cost estimation, it is necessary to obtain vendor quotes, which are subject to change due to market-dependent time windows. These quotations are typically conducted during the 60% design phase, at which point there is an understanding of the specific equipment ratings and brands to be used.
- This report evaluates the site's existing electrical infrastructure using customer-provided data on the main breaker and bus capacity, as documented in the client-provided file " Corp Yard Electrical Sheet." AECOM has assessed whether the existing electrical system can support the proposed PV array and BESS installation. However, as this is a feasibility study, an on-site assessment is required for a definitive determination. A site visit should be conducted during the advanced design phase, typically at the 30% design stage, to confirm site-specific conditions.
- AECOM has estimated the potential PV generation capacity based on the client-identified available area, as documented in the client-provided file "Go-No Go PV Areas." However, a site assessment is required in later project phases, typically at the 30% design stage, to ensure that the site has the necessary infrastructure for PV array installation. This includes evaluating civil structures, load-bearing capacity, particularly for rooftop installations, and other critical conditions necessary for successful implementation.
- This report uses a regionalized estimate of general production (kWh) to calculate the amount of greenhouse gas emissions avoided through PV generation. The calculation is based on the U.S. EPA Emissions & Generation Resource Integrated Database (eGRID).
- This report clarifies that other charges such as connection fees, required service charges, and taxes remain unchanged. The analysis focuses solely on the bill components directly affected by the installation of PV and BESS under the NEM 3 framework.
- Energy exported to the utility is valued at approximately one quarter of the applicable retail electricity rate for the purposes of this analysis under NEM factors.

AECOM utilized the following tools in conducting the analysis:

- AECOM Internal Tools: Proprietary tools developed by AECOM for analyzing energy patterns and evaluating system performance in simulated environments. These tools are designed to assess energy costs for applications such as peak shaving, energy trading, etc. in DER implementations.
- HelioScope: Web-based software tool used for the design and performance analysis of photovoltaic systems. It combines system layout design with energy simulation, allowing users to model rooftop, ground-mounted, and canopy PV installations. The software factors in module placement, tilt, azimuth, shading, and local weather data to provide accurate estimates of system capacity and expected energy generation.

Site Information

This study is conducted for the Corporation Yard complex, located along Public Safety Way. The two meters indicate that the site currently consumes about **3,726,124 kilowatt-hours kWh per year**.

In terms of electrical infrastructure, the site is equipped with a main switchboard rated for 1200-ampere (A), 480Y/277-volt (V), three-phase, four-wire configuration, rated at 65 kilo-ampere interrupting capacity (kAIC). It is fed from a utility pad-mounted transformer and distributes power to several feeder sections serving different buildings such as police, administration, maintenance, and auxiliary facilities.

The total connected load is approximately 700 kilovolt-ampere (kVA), with copper feeders sized up to 500 kilo circular mils (kcmil) and voltage drops below 3%. A distribution board rated at 400 A supplies subpanels, a transformer rated at 75 kVA, and a natural-gas or diesel generator rated at 200 kilowatts (kW) through an automatic transfer switch rated at 800 A for emergency loads.



Figure 1. Site Location

The user has identified no-go areas for PV as the below image shows.



Figure 2. No-Go Areas for PV

Incentive Programs

AECOM has identified three key incentive programs that could benefit the subject site, focusing on renewable energy production and advanced energy storage systems.

The Investment Tax Credit (ITC) and Production Tax Credit (PTC) are federal incentives that reduce the cost of renewable energy projects. ITC offers a tax credit based on a percentage of upfront investment costs, while PTC provides a per-kilowatt-hour credit for electricity generated over time.

Production Tax Credit

Under this initiative, the project is eligible for a tax credit ranging from 0.3 cents to 1.5 cents per installed kWh. The specific value of the credit is determined by several factors, including the project's adherence to certain requirements such as complying with labor standards and using domestic materials.

The PTC program pays for each kilowatt-hour produced over a 10-year period, with government entities receiving the benefit as direct pay instead of a tax credit. For this project, with an estimated 4,128,000 kWh per year, the best case at 1.5 ¢/kWh would yield about $61,920 annually, totaling around $619,200 over 10 years.

Investment Tax Credit

The City may utilize either the ITC or the PTC, but not both. Because the project has not yet begun construction, the ITC remains the preferred alternative. In this scenario, the project is assumed to be located within a qualifying low-income census tract, enabling eligibility for the additional 10 percent bonus credit.

Under the Low-Income Communities Bonus Credit Program, projects located within a designated low-income community, as defined by the 2016–2020 census tract boundaries in Figure 3, receive an additional 10 percentage points added to the base ITC. This increases the total credit from 30 percent to 40 percent of the eligible project cost.

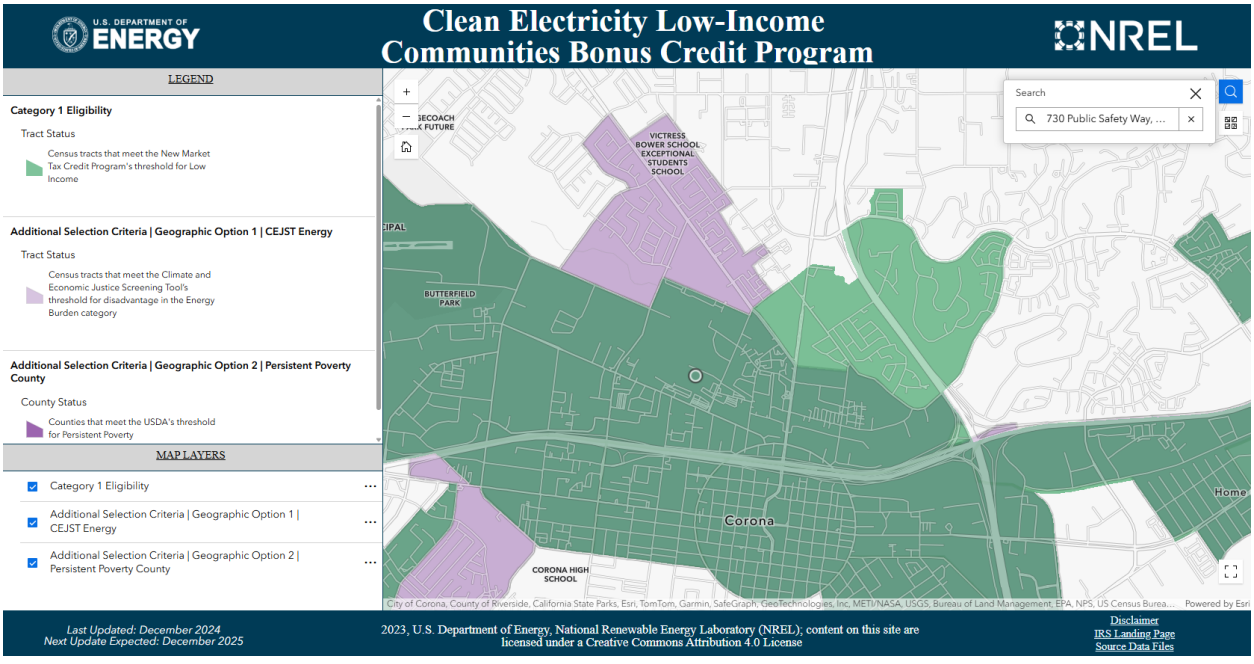


Figure 3. Clean Electricity Low-Income Communities Bonus Credit Program Map

Using NLR's CAPEX range of $1.75–2.00/watt (W) direct current (DC), the proposed 2,360 kW DC PV system would cost between $4,130,000 and $4,720,000. With a 40 percent ITC, the resulting direct-pay benefit increases to $2,478,000 a $2,832,000, reducing the project's upfront capital requirements accordingly.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) is California's primary incentive designed to reduce the upfront cost of energy storage systems. The program has three levels:

- **General Market:** For projects located outside Disadvantaged Communities (DAC). Typical incentive: $0.10/Wh.
- **Equity (DAC):** For projects located within a DAC. Incentive: $0.85/Wh.
- **Equity Resilience**: For critical facilities within a DAC and in PSPS or high fire-risk zones. Incentive: $1.00/Wh.

The project is located within a DAC, so it qualifies for the Equity level. Using an NLR-based cost of $450/kWh, the 2000-kWh battery would cost approximately $900,000. At the Equity incentive rate of $0.85/Wh, the available support would total $1,700,000, which is sufficient to fully cover the system cost within SGIP's allowable limits.

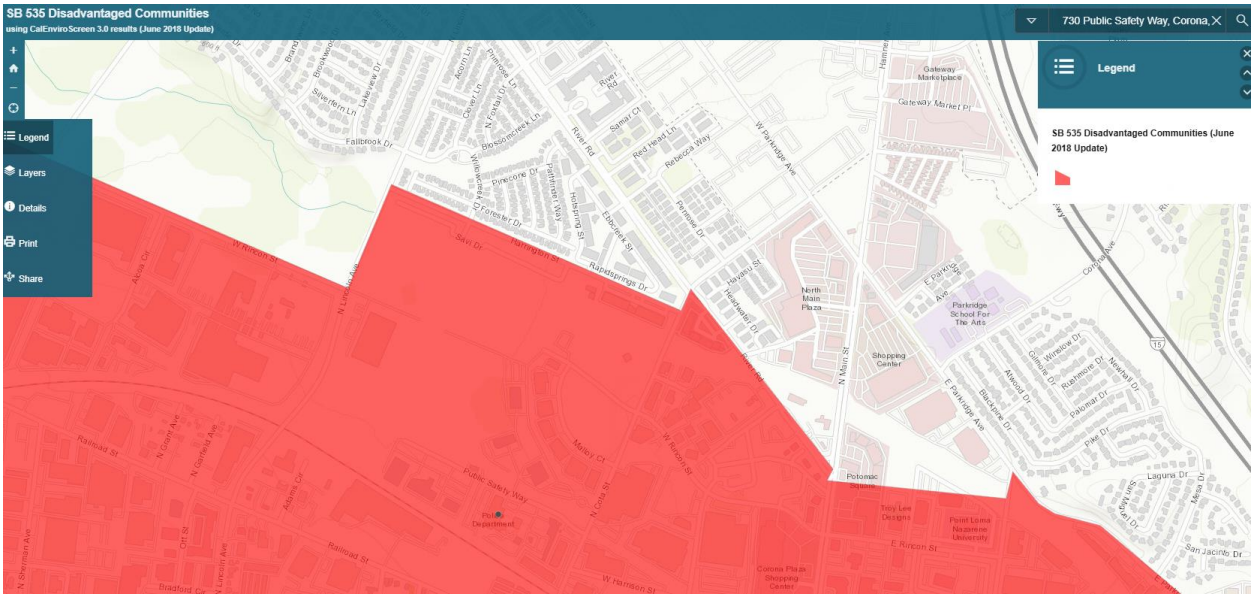


Figure 4. SB 535 Disadvantaged Communities Map

Scenarios & Analysis

Case 0: Current Situation (Baseline)

Tariff & Contract Type

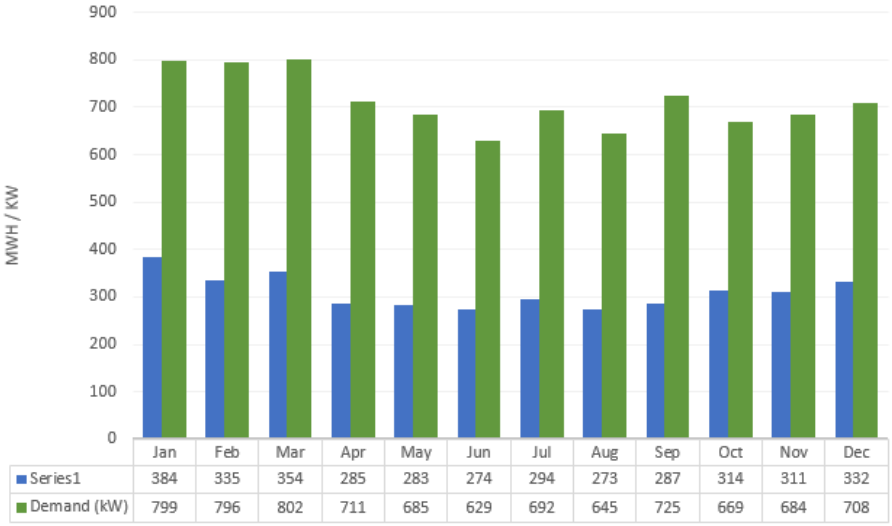
The site is currently served by SCE under the TOU-8-D CPP tariff, which is designed for small to medium commercial customers. This rate structure separates costs into energy charges (based on kilowatt-hours consumed) and demand charges (based on the highest kilowatt demand registered during the billing cycle). In addition, prices vary by time-of-use periods—on-peak, mid-peak, and off-peak—so the timing of energy use significantly affects overall costs.

Being on this tariff means the site's operating expenses are directly tied not only to how much energy is consumed but also to when it is consumed and how high the peak demand reaches.

The tariff cost presents the costs as totals (delivery + bundle). The prices were used as the basis for this study. While they may fluctuate slightly month to month depending on market conditions, these variations are generally minor.

Monthly & Annual Energy Consumption and Demand

The site currently consumes 3,726,124 kWh annually, with January being the highest month at about 383,927 kWh and August the lowest at about 272,925 kWh. In terms of demand, March records the peak at around 802 kW, while June is the lowest at about 629 kW. The following graph presents this historical data for the 2024–2025 period.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Series1	384	335	354	285	283	274	294	273	287	314	311	332
Demand (kW)	799	796	802	711	685	629	692	645	725	669	684	708

Figure 5. Historic Site Energy Profile

Monthly & Annual Energy Costs

The site currently spends about $ 823,623 per year in energy and demand cost, with approximately $484,884 in energy costs and $359,560 in demand charges, based on tariff TOU-8-D CPP simulation. For this analysis, we are focusing only on energy and demand costs, as these are the components directly impacted by the installation of a PV system.

Case 1: PV Only

Installed Capacity & Location

The PV system for the site was sized to offset approximately 110% of current consumption, with the goal of fully offsetting present usage while reserving about 10% additional capacity for future growth. The placement areas for the PV installation were identified according to customer requirements. The system capacity is estimated at 2,360 KW DC, with an expected annual production of about 4,128,000 kWh.

Figure 6 presented the modeled energy production throughout the year, and Figure 7 identifies the designated PV installation areas on the site.

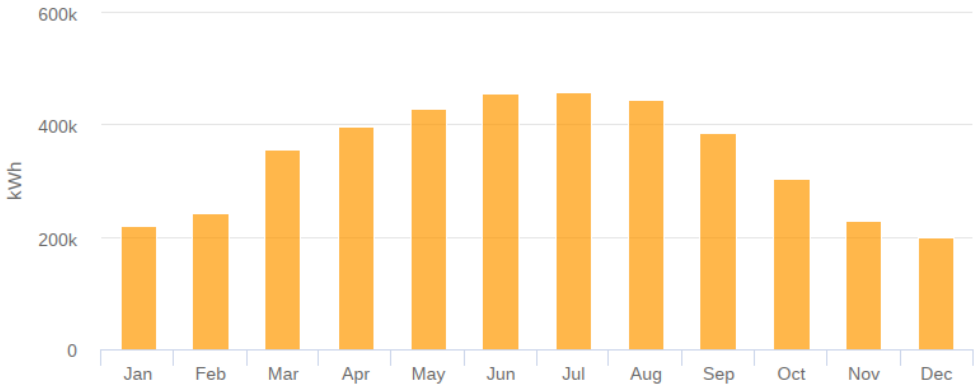


Figure 6. Modeled PV Production



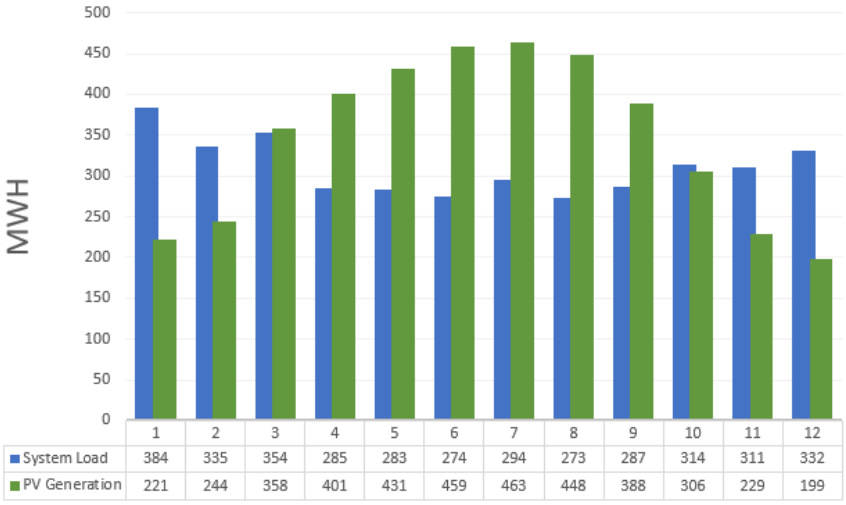
Figure 7. Modeled PV Installation Areas

Modeled PV Production

The modeled PV system is projected to generate an average of **345,730 kWh per month**, with an estimated **annual production of 4,128,766 kWh**.

This scenario does not include a BESS, so the excess energy produced need be exported to the utility, which requires entering a Net Energy Metering (NEM) contract with the utility service provider. Under the currently available NEM tariff, NEM 3.0, exported electricity is credited at dynamic rates that vary by month, hour of day, and weekday, ranging from as low as $0.01/kWh during midday hours to over $1.00/kWh during peak evening hours in high-demand months like August and September. This study has calculated projected benefits from this arrangement.

Figure 8 compares historic monthly energy consumption and modeled PV generation. Not all solar energy will be consumed on-site, as excess daytime production may exceed demand and be exported to the grid, while nighttime demand cannot be covered since there is no generation after sunset and no battery to store the excess in this scenario.



	1	2	3	4	5	6	7	8	9	10	11	12
System Load	384	335	354	285	283	274	294	273	287	314	311	332
PV Generation	221	244	358	401	431	459	463	448	388	306	229	199

Figure 8. Modeled PV Output vs. Site Demand

Capital Expenditures

Based on NLR benchmark CAPEX values for commercial rooftop solar, the estimated cost to install a 2,360 kW DC PV system in Riverside County, California falls in the range of $1.75 to $2.00 per watt DC. This translates to a total investment of **approximately $4,130,000 – $4,720,000 for the complete system**.

These figures include **typical equipment, installation, and soft costs**, reflecting average market conditions for commercial-scale projects. Actual costs may vary slightly depending on site-specific conditions such as roof structure, permitting, interconnection requirements, and labor. However, the NLR benchmarks provide a reliable basis for estimating the capital cost of a system of this size and type in the region.

Operating Expenses

According to NLR's 2024 benchmark data, the annual operations and maintenance (OPEX) cost for commercial rooftop PV systems is about $19 per kW-DC. For a 2,360 kW DC system, this translates to an **estimated yearly OPEX** of roughly **$47,200** covering routine maintenance, monitoring, and related operational expenses.

Economic Metrics

The analysis shows that installing a PV system at the site under NEM3 provides measurable financial benefits by offsetting both energy and demand charges. Without solar, the facility currently spends about $823,623 annually on utility costs. With the PV system in operation, the energy cost is reduced to approximately $277,278 per year, while the demand cost drops to about $283,420 per year. In addition, the system generates excess electricity during the day that cannot be fully consumed on-site. Under NEM3 rules, this exported energy represents an additional benefit of roughly $84,789 annually. Taken together, these reductions and export credits bring the facility's total utility bill down to **$475,909 per year**, achieving an **overall savings of about 42%** compared to current expenses

Payback Period and Return on Investment

The financial analysis shows that without PV, the facility spends approximately $823,623 per year on utility costs. With a 2360 kW DC PV system installed, the annual cost is reduced to about $475,909, resulting in yearly savings of roughly $347,714. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system is estimated at $4,720,000, but with the 40 percent ITC direct pay, the net investment is reduced to approximately $2,832,000. In addition, the system carries an annual OPEX of $47,200, which slightly offsets the yearly savings. Taking these factors into account, the project generates a net benefit of about $347,714 minus $47,200 per year after OPEX. This results in a simple payback period of approximately 9 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross Savings ($)	Net Savings after OPEX ($)	Cumulative Cash Flow ($)
1	347,714	300,514	-2,531,486
2	358,145	309,529	-2,221,957
3	368,889	318,815	-1,903,142
4	379,956	328,379	-1,574,763
5	391,355	338,231	-1,236,532
6	403,096	348,378	-888,154
7	415,188	358,829	-529,325
8	427,644	369,594	-159,731
9	440,473	380,682	220,951
10	453,688	392,102	613,053
15	467,298	403,865	1,016,918
20	481,317	415,981	1,432,900

Table 1. Return on Investment w/ 3% Inflation: Case 1

Technical Feasibility

Based solely on the one line diagrams provided, the existing electrical distribution uses a main distribution board (VMDB) with multiple feeder breakers supplying various loads. To interconnect an additional 2360 kW DC PV system, a new dedicated backfeed breaker must be added at the main distribution board or at the nearest suitable bus with available ampacity. The breaker must match the bus rating and fault current requirements visible in the diagrams.

The existing equipment will require a protection coordination review to ensure the new PV contribution does not exceed available interrupting ratings. Relay settings for upstream devices, including the main breaker, must be updated to account for reverse power flow and fault contribution from the PV inverters. Any indicated protective relays or trip units on the drawings must be rechecked for pickup, time delay, and directional elements if applicable.

Conductor and feeder upgrades may be needed where the bus loading increases due to PV backfeed. The one line shows several feeders already utilizing significant breaker capacity, so verification of bus loading, spare capacity, and temperature ratings is required. If no spare breaker positions are available, a bus extension or breaker replacement may be required.

Finally, the interconnection must follow the point of common coupling shown on the drawings. Utility coordination will be required to confirm transformer backfeed limits, anti-islanding requirements, and visible disconnect placement near the main service location, as indicated in the existing diagram structure.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 4,128,000 kWh per year. Using the U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:

- Carbon dioxide (CO_2): 1,768,699 pounds (lbs) (802.3 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 1,774,970 lbs (805.1 metric tons) avoided annually
- Nitrogen oxides (NO_x): 1,370 lbs (621.6 kg) avoided annually
- Sulfur dioxide (SO_2): 82.6 lbs (37.4 kg) avoided annually.

Case 2: PV + BESS

System Components

This scenario assumes the same PV array described in Case 1 and a BESS sized for surplus PV production. The day with the highest energy surplus in our simulation occurred on May 16, during which the PV system produced 16,234 kWh, the site consumed 6,542 kWh, and the resulting surplus was 9,691 kWh. To size the BESS, we ran several iterations based on the available surplus energy and applied an algorithm that simulates the charge and discharge cycles of one year. This techno-financial analysis indicates that the optimal BESS capacity is approximately 2000 kWh.

This simulation factor ensures that even under variations in production or demand, all possible excess solar energy generated during the day can be stored. The stored energy is then available for use at night or during periods when PV production does not fully cover the site's demand.

By doing so, most of the units of solar energy produced on-site are consumed daily by the facility, preventing as little as possible any export to the grid. As a result, the utility bill for both energy and demand charges can effectively be reduced to zero, with only fixed or non-energy charges remaining.

Modeled Energy Flows

By installing a 2000 kWh battery, we ensure that all the energy generated on-site is consumed by the facility itself. The charge and discharge profile of the battery is designed so that any PV surplus during the day is immediately stored in the battery rather than exported to the grid. Later, if the site demand exceeds the PV generation while there is still energy stored in the battery, the deficit is supplied from the battery.

This operational strategy minimizes or even eliminates consumption from the utility, since the PV and battery combination is prioritized to cover the load at all times. On an annual basis, the system is expected to produce slightly more energy than the site requires, leaving a surplus of around 10%, but this excess is negligible in terms of the overall utility bill.

Capital Expenditures

According to NLR benchmark data, the capital expenditure (CAPEX) for a commercial-scale 2,360 kW DC rooftop PV system in Riverside, California is estimated at $2,832,000 under ITC incentive, based on installation costs of $1.75–2.00 per watt DC.

For storage, NLR's 2025 cost projections indicate a CAPEX of $450 per kWh for the high-cost scenario. Applying this benchmark to a commercial-scale 2,000 kWh battery system represents an investment of roughly $900,000, and under the SGIP program this amount can be fully covered, effectively funding 100% of the BESS system

Together, the **combined CAPEX for the PV and BESS systems** is estimated at **$2,832,000** representing the expected upfront investment for a commercial solar-plus-storage project of this size.

Operating Expenses

According to NLR benchmark data, the annual operations and maintenance (OPEX) cost for a commercial-scale 2,360 kW DC rooftop PV system is estimated at $47,200 USD.

NLR data indicates an operating cost of approximately $4 per kW-year. For a commercial-scale 2,000 kWh battery system, this results in an annual OPEX of about $8,000.

Together, the **combined OPEX for the PV and BESS** systems is **approximately $55,200 per year**, covering routine maintenance, monitoring, and system management.

Economic Metrics

The analysis shows that installing a commercial-scale PV system paired with a 2,000 kWh battery under NEM 3 provides strong financial advantages by allowing a substantial portion of the solar energy produced by the PV system to be consumed on-site.

In several cases, PV production exceeds the facility's demand, and the surplus can be stored in the BESS for later use. However, without a battery system, the facility cannot absorb all of this excess energy, since any unused generation must be consumed the moment it is produced. This unused energy would otherwise need to be exported to the utility grid, where under current NEM rules it would be compensated at only about 25 percent of the retail electricity rate. Given that time-of-use pricing makes stored energy far more valuable during high-cost periods, it becomes financially preferable to store surplus solar rather than sell it.

Without a BESS, exporting this excess would generate $84,789 but the facility would still face an annual utility cost of $475,909 By contrast, installing the BESS reduces grid reliance and allows the facility to consume a vast of its solar production during higher-priced periods, resulting in a lower annual utility bill of $239,895.

To remain conservative, this analysis assumes that 10% of annual energy costs remain due to efficiency losses, imperfect alignment of PV output and site load, and seasonal variability.

Payback Period and Return on Investment

The financial analysis shows that without PV + BESS, the facility spends approximately $823,623 per year on utility costs. With a 2,360 kW DC PV system and 2,000 kWh BESS system installed, the annual cost is reduced to about $ 239,895 resulting in yearly savings of roughly $583,728. When accounting for modest energy price inflation over time, these annual savings are expected to increase gradually, further improving the project's economics.

The total capital cost of the system under ITC and SGIP incentives is estimated at $2,832,000. In addition, the system carries an annual OPEX of $55,200 Taking these factors into account, the combined system generates a net benefit of about $528,528 per year after OPEX. This results in a simple payback period of approximately 6 years, after which the facility will continue to benefit from lower operating costs and inflation-protected savings for the remaining life of the system.

Year	Gross-Savings ($)	Net-Savings after OPEX ($)	Cumulative Cash Flow ($)
1	583,728	528,528	-2,303,472
2	601,240	544,384	-1,759,088
3	619,277	560,716	-1,198,372
4	637,856	577,537	-620,835
5	656,991	594,863	-25,972
6	676,701	612,709	586,737
7	697,002	631,090	1,217,828
8	717,912	650,023	1,867,851
9	739,449	669,524	2,537,375
10	761,633	689,609	3,226,984
11	784,482	710,298	3,937,282
12	808,016	731,607	4,668,888

Table 2. Return on Investment w/ 3% Inflation: Case 2

Technical Feasibility

The available single-line sheets show multiple downstream distribution boards served at 277/480 V, 3-phase, 4-wire, with bus ratings of 600 A (e.g., PSDB, FIDB) and 400 A (e.g., WHDB, VMDB, SHDB). These include PSDB with a 600 A bus and transformers to 208/120 V loads; WHDB, VMDB, and SHDB each depict 400 A buses feeding branch panels and equipment.

Given the scale of the new resources (PV 2,360 kW DC and BESS 2,000 kWh), a load-side backfeed at any of the 400–600 A distribution boards is not practical because the added generation breakers would drive bus sums beyond the NEC 705.12 (120% rule) limits on these buses. The diagrams also show these boards already serving numerous feeders and transformers, leaving limited spare capacity. A simple breaker addition at these boards is therefore not code-viable at the depicted ratings.

The recommended approach is to interconnect on the supply side at the service equipment upstream of these distribution boards, or via a new, dedicated generation/intertie section that is line-side to the existing 400–600 A boards. This removes the PV/BESS breakers from the 120% bus constraint and allows proper metering and utility protection to be applied while preserving downstream board capacities shown on the drawings.

Implement a protection and coordination review: verify main/service OCPD settings, add required anti-islanding and reverse-power protection at the intertie, and coordinate with any transformer-fed 208/120 V panels. Provide appropriately rated intertie breakers, labeling, and grounding/bonding, and size conductors and raceways from the PV and BESS to the new intertie in accordance with utility and NEC requirements, keeping existing 400–600 A boards as load-only as depicted.

Greenhouse Gas Emission Reductions

The proposed solar PV system is expected to generate 4,128,000 kWh per year. Using the U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID) factors for the CAMX subregion (California), this renewable generation will offset grid electricity and reduce associated Scope 2 emissions as follows:

- Carbon dioxide (CO_2): 1,768,699 pounds (lbs) (802.3 metric tons) avoided annually
- Carbon dioxide equivalent (CO_2e): 1,774,970 lbs (805.1 metric tons) avoided annually
- Nitrogen oxides (NO_x): 1,370 lbs (621.6 kg) avoided annually
- Sulfur dioxide (SO_2): 82.6 lbs (37.4 kg) avoided annually. EPA

CASE 3: BESS Only

Critical Load Identification

The facility is classified as a general municipal operations center consisting of administrative, warehouse, vehicle maintenance, and support buildings. Under NEC 700 and NFPA 110, only life-safety systems are required to receive emergency power. These include egress illumination, exit signage, fire alarm systems per NFPA 72, and associated emergency communications where provided.

NEC 701 legally required standby loads may include limited security systems, access control for egress doors, and critical ventilation required for safe shutdown conditions. No evidence of mission-critical process equipment requiring continuous operation under NEC 700 was identified.

Based on the facility type and applicable code requirements, the critical load is estimated at 25 percent of the total connected load. For a 1300 kW connected load, the calculated critical load is 325 kW.

Required Backup Duration

No drawings provide a prescribed emergency duration, so the default requirement of 4 hours is applied. This duration aligns with typical expectations for emergency and legally required standby systems when no project-specific mandate is provided.

Battery Capacity & Infrastructure

The battery energy storage system is sized to support 325 kW of emergency demand for 4 hours.

Required battery power rating: 325.0 kW
Required battery energy capacity: 1300 kWh

The inverter continuous output must meet or exceed 325.0 kW. The battery usable capacity must be at least 1300 kWh, accounting for depth-of-discharge limits and inverter efficiency losses.

Integration requires connection on the emergency distribution side of the system, downstream of the automatic transfer switch to ensure separation between normal and emergency circuits. Bus capacity must be verified to accommodate an additional 325 A equivalent load at system voltage. Breaker sizing, feeder ampacity, and short-circuit contributions must be evaluated to confirm compliance with NEC 705 and equipment interrupting ratings.

Capital Expenditures

A lithium-ion BESS rated approximately 325 kW / 1300 kWh at an installed cost of $450/kWh results in an estimated base system cost of approximately $585,000. This value reflects current commercial market benchmarks for containerized or cabinet-based lithium-ion systems at medium scale. Final installed cost may vary depending on enclosure type, power conversion system configuration, site integration complexity, and permitting requirements.

Electrical scope may include installation of a dedicated BESS breaker, modifications to emergency switchboard sections, verification of bus capacity, potential conductor upsizing if load-side interconnection limits are approached, installation of external service disconnects, pad-mounted or containerized placement, and associated structural or foundation work. Protection coordination updates, relay programming, and short-circuit analysis are required prior to commissioning.

Under the California SGIP incentive program, qualifying resilience projects can receive incentive levels that may be fully cover a substantial portion or, in certain equity or critical resilience categories, up to the full capital cost of the BESS system, subject to program caps, eligibility criteria, and funding availability.

Operating Expenses

The expected operating cost (OPEX) is about $5,200 per year, also based on NLR reference values. This covers preventive maintenance, monitoring software, and NFPA 110 testing requirements. Battery replacement is typically required after 10–12 years of service.

Return on Investment & Qualitative Benefits

While a conventional financial return cannot be directly applied to this case, the value of a BESS is framed in terms of resilience, reliability, and compliance. Such systems are designed to ensure uninterrupted operation of life-safety and legally required standby equipment during extended utility outages. The benefits include maintaining operational continuity, reducing safety risks, and ensuring compliance with NFPA 110, NFPA 70, and NFPA 72.

However, justification must be evaluated against existing backup assets. If existing generator(s) capacity exceeds the 325 kW emergency requirement, the incremental resilience provided by the BESS may be limited relative to cost. In such cases, implementation becomes a policy-driven redundancy decision rather than a strict code necessity.

Technical Considerations

Integration requires confirming that the bus capacity accommodates the added contribution of the BESS, verifying compliance with the 120-percent load-side interconnection rule, and evaluating whether breaker or feeder upgrades are required to support the new equipment. The separation between normal and emergency circuits must remain intact through the transfer sequence, and the system must be coordinated for short-circuit ratings and protective device selectivity. The BESS installation must also account for UL 9540A-related spacing, ventilation, and fire-mitigation requirements, ensuring compatibility with the existing electrical architecture shown in the one-line diagrams.

Decision Matrix and Scenario Comparison

In order to determine the most appropriate scenario for the site, four scenarios were developed and analyzed: business as usual (Case 0), installing a PV system only (Case 1), installing PV with a BESS (Case 2), and installing a BESS only (Case 3). Each case was evaluated in terms of resilience value, capital and operating expenditures, energy savings, payback period, and technical feasibility. The decision matrix summarizes the comparative performance of these options.

Criteria	Case 0: Baseline	Case 1: PV Only	Case 2: PV + BESS	Case 3: BESS Only
Resilience Benefit	None	Limited (daytime only)	High (self-consumption, some coverage)	High
CAPEX ($)	0	~ $2,832,000	~$2,832,000	~$585k (SGIP funding can reduce the project cost to nearly zero)
OPEX ($/yr)	Current	~$47k	~$55k	~$5,200
Annual Utility Bill ($)	~$823k	~$475k	~$240k	~$823k (no reduction)
Annual Savings ($)	–	~$347k	~$583k	Minimal (non-financial)
Payback Period	–	~9 years	~6 years	No ROI
GHG Reduction	None	~805 $MTCO_2e$ avoided annually	Same as Case 1	None
Technical Feasibility	Already in place	Requires breaker adjustment	Requires breaker + storage integration	Requires breaker adjustment

Table 3. Scenario Comparison

Conclusion

Based on the comparative analysis, **Case 2 (PV + BESS)** emerges as the preferred scenario. While Case 1 (PV only) provides meaningful savings and reduces utility costs by approximately 42%, integrating a BESS enables the facility to consume nearly all on-site solar generation during high-value periods, significantly increasing economic benefits.

The site is equipped with an existing 500 kW backup generator, which is more than sufficient to support emergency and standby operations. Because resilience is already adequately covered by this generator capacity, Case 3 (BESS only) does not provide incremental operational value. A standalone battery system would not reduce the utility bill in a meaningful way and would duplicate resilience capability that is already available on site.

Case 2 delivers the strongest overall performance because it maximizes annual savings, reduces the utility bill from approximately $823,623 to $239,895, and achieves a simple payback of about six years. The system benefits from both ITC (direct pay) and SGIP incentives, which substantially lower upfront capital requirements. In addition, PV + BESS provides the highest resilience benefit, enabling the facility to operate independently during outages and reducing reliance on the utility grid. This makes Case 2 the most financially advantageous and operationally resilient strategy for the site.

Summary of Strategy & Benefits

The selected strategy focuses on installing a 2,360 kW DC PV system paired with a 2,000 kWh BESS sized to capture and shift daily solar surplus. This combined approach provides the following advantages:

- **Resilience**: Enables sustained operation during outages by shifting and storing energy, reducing dependency on external grid conditions.
- **Economic Savings**: Reduces annual utility costs by ~71%, from about $823k to $240k, maximizing the value of on-site solar.
- **Financial Feasibility**: Achieves a simple payback of roughly six years, driven by high annual savings and strong federal and state incentives.
- **Environmental Impact**: Avoids approximately 805 metric tons of CO_2e annually, aligning with regional climate objectives.
- **Incentive Optimization**: Utilizes the 40% ITC and the SGIP Equity program, which can fully fund the 2,000 kWh battery system.
- **Operational Stability**: Minimizes exposure to rising electricity and demand charges by supplying the majority of site load with on-site generation.

Next Steps

To advance the project, the following steps are recommended:

1. **Detailed Design & Site Assessment:** Conduct a 30% design phase evaluation, including structural assessment of the roof, electrical interconnection details, and shading analysis
2. **Vendor Quotations:** Obtain updated vendor quotes for PV system equipment, installation, and interconnection to refine cost estimates beyond NLR benchmarks
3. **Permitting & Interconnection:** Coordinate with electric utility to complete the interconnection study and ensure compliance with NEM 3 tariff rules
4. **Finalize Incentive Applications:** Submit applications for the 30% ITC (direct pay) to secure federal funding and reduce upfront capital cost
5. **Procurement & Installation:** Issue RFPs for procurement and construction, selecting qualified contractors with experience in municipal PV installations
6. **Commissioning & Monitoring:** Upon installation, perform commissioning tests, integrate the system with monitoring platforms, and establish an operations and maintenance (O&M) plan to ensure reliable long-term performance

Appendix

Incentive Programs

This section outlines how the incentive programs function and provides relevant information about them. Specific application of these programs to presented scenarios is explored in previous sections.

Inflation Reduction Act

The Inflation Reduction Act of 2022 stands as a significant piece of legislation designed to strengthen the United States' commitment to fighting climate change by making considerable investments in renewable energy. A key feature of the Inflation Reduction Act is its financial incentives, namely the Investment Tax Credit (ITC) and the Production Tax Credit (PTC), which aim to accelerate the adoption of renewable energy technologies.

The ITC allows for a significant tax credit for investments in renewable energy technologies, including solar panels and wind turbines, directly reducing the upfront cost of these systems. This makes renewable projects more financially viable and attractive to investors and consumers alike. On the other hand, the PTC provides a per-kilowatt-hour tax relief for the production of energy from renewable sources, incentivizing the operation and expansion of renewable energy facilities.

Notably, Inflation Reduction Act programs have been subject to change in recent legislation. Presented here are active opportunities as of the time of the report.

Production Tax Credit

The Production Tax Credit (PTC) within the framework of the Inflation Reduction Act offers considerable financial incentives for renewable energy projects, primarily designed to decrease the federal income tax liability based on the electricity produced per kilowatt-hour.

The PTC directly reduces the federal income tax for taxable entities. Furthermore, for non-taxable entities such as local governments, educational institutions, or nonprofit organizations, the PTC allows these credits to be monetized, facilitating their involvement in renewable energy initiatives. This provision is applicable for projects that become operational between January 1, 2023, and December 31, 2032, providing a broad window for planning and implementation.

Projects located in designated low-income energy communities receive further incentives. The PTC is structured to be claimable annually for a decade from the start date of operations of the qualifying renewable system, providing long-term financial support. This current structure of the PTC is set to continue through the end of 2024. Starting from January 1, 2025, the credit system will transition to a technology-neutral format, broadening the scope to include a wider array of technologies and fostering a more inclusive approach to renewable energy incentives.

As of the date of this report, the program is still active but solar projects must have “begun construction” by July 4, 2026.

The City project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

Investment Tax Credit

The Investment Tax Credit (ITC) established under the Inflation Reduction Act offers a powerful incentive for deploying renewable energy technologies by providing a reduction in federal tax liability. This reduction is calculated as a percentage of the capital investment made in eligible energy systems. Taxpayers can apply the ITC to their federal income tax for the year the technology is installed, significantly decreasing their tax burden.

Starting January 1, 2023, special provisions enable tax-exempt entities such as local governments and nonprofits to receive direct payments equivalent to the value of the credit. This arrangement improves the liquidity and financial feasibility of renewable projects for these organizations. The scope of eligible technologies under the ITC is broad, encompassing solar panels, wind turbines, fuel cells, and other renewable energy systems.

As of 2025, the Investment Tax Credit (ITC) for solar projects is set at 30% of the eligible costs, encompassing both the equipment and installation expenses. This rate is scheduled to decrease to 26% in 2033 and further to 22% in 2034. Systems rated under 1 megawatt (MW) qualify for the full 30% without having to comply with additional requirements; larger systems will only receive the full amount if they meet specific labor requirements. These include paying prevailing wages to workers during construction and using apprentices to perform a portion of the total construction hours (15% after 2023). Bonus credits are available based on site location, e.g., low-income communities.

The ITC is set to continue delivering these benefits at its current rate until 2032, contingent upon meeting the specific project criteria laid out in the act. Looking ahead, post-2024, the ITC will transition to a technology-neutral system, which will be applicable to all zero-emissions technologies, reflecting a shift towards a more inclusive and adaptable approach to supporting renewable energy development.

HHZP project can take advantage of either the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), but they cannot utilize both simultaneously. Since the project has not already commenced, it is more advantageous to opt for the ITC.

As of the date of this report, the program is still active but critical deadlines for project eligibility and complete operability are quickly approaching in 2026 and 2027, respectively.

Self-Generation Incentive Program

The Self-Generation Incentive Program (SGIP) offers financial incentives to non-residential customers of utility Company to encourage the adoption of energy storage systems. These systems help businesses prepare for power outages that may occur due to weather, emergencies, or other unforeseen events. The SGIP funding is authorized through 2024, with incentives structured to decrease over time as funding milestones are reached or as more participants enter the program.

Non-residential customers have access to three types of SGIP rebates: General Market, Equity, and Equity Resilience. Furthermore, SGIP incentives are significantly higher for vulnerable or disadvantaged communities through the Equity and Equity Resilience categories.

Incentives are typically paid upfront for residential systems upon project completion and site verification, while nonresidential systems may receive half upfront with the balance paid based on the system's performance over time. Eligibility for SGIP incentives extends to residential, commercial, industrial, agricultural, and municipal customers of specific utilities including Pacific Gas & Electric, Southern California Edison, SoCalGas, San Diego Gas & Electric, and those managed by the Center for Sustainable Energy.

To be eligible for this rebate, a facility must satisfy two conditions: firstly, it must fall under the category of a government agency, educational institution, non-profit organization, or small business. Secondly, it must fulfill at least one of the following requirements: be located in a Disadvantaged Community (DAC), be situated in a census tract where the Median Household Income of the Statewide Median Income or be situated in California Indian Country.

On the other hand, the equity resilience rebate offers a rate, covering a percentage of the cost of an average energy storage system. To qualify for this rebate, a facility must meet certain requirements. Firstly, it must have experienced two or more utility Public Safety Power Shut-offs (PSPS), or it should be located in a Tier 2 or 3 High Fire Threat District (HFTD) and serve customers in DACs or Low Income Communities. Secondly, it must fulfill at least one of the following additional criteria:

- Be a police station, fire station, emergency response provider, emergency operations center, 911 call center, medical facility, private and public natural gas, electric, water, wastewater, or flood facility, jail or prison, utility-designated PSPS assistance center, cooling center, homeless shelter.
- Be a grocery store, supermarket, or corner store with less than $15 million in annual gross receipts.

- Be an Independent Living Center or a Food Bank.

Modeling Assumptions

The modeling conducted for this feasibility study was based on standard industry benchmarks, available site data, and conservative assumptions to ensure realistic projections. The following key assumptions were applied:

1. **Energy Consumption Baseline** – Historical hourly load data (8,760 points) from the facility was consolidated to represent a typical annual profile. This served as the reference for sizing PV and BESS systems.
2. **PV System Costs** – Capital expenditure (CAPEX) and operations and maintenance (OPEX) values were derived from the National Laboratory of the Rockies (NLR) 2024–2025 benchmarks for commercial rooftop systems. PV CAPEX was assumed at $1.75–$2.00/W DC, with OPEX at ~$19/kW-year.
3. **BESS Costs** – Battery energy storage CAPEX was modeled using NLR 2025 benchmarks at ~$350/kWh. OPEX was assumed at ~$40/kW-year, covering maintenance, monitoring, and lifecycle management.
4. **ITC Incentives** – A 30% Investment Tax Credit (direct pay) was assumed, reducing upfront project cost. No additional low-income or disadvantaged community adders were included since the site does not qualify.
5. **Performance Parameters** –
    - PV generation modeled with HelioScope using site tilt, azimuth, and shading factors.
    - Battery modeled with 90% round-trip efficiency and daily cycling where applicable.
    - Energy inflation rate of 3% annually applied to utility costs.
6. **Utility Tariff** – The analysis used the most recent Southern California Edison tariff, **TOU-GS-2 Option D**, as published in the file *ELECTRIC_SCHEDULES_TOU-GS-2_2025*. It was assumed under the current **NEM 3** framework. Exported PV energy was valued at ~25% of retail rate. Since tariff structures and prices are subject to future changes, the financial outcomes presented here should be viewed as indicative estimates rather than fixed projections.
7. **Infrastructure** – Electrical interconnection feasibility was preliminarily evaluated using customer-provided single-line diagrams. Minor breaker adjustment (600 A to 500 A) was assumed to comply with NEC 705.12 120% busbar rule for PV backfeed.
8. **Environmental Impact** – Greenhouse gas (GHG) reduction estimates were calculated using EPA eGRID emission factors for the CAMX subregion, applied to modeled PV generation.

Disclaimer: These figures are rough estimates intended for feasibility-level evaluation. If more precise values are required, additional detail must be developed through site-specific engineering, vendor quotations, and utility coordination during the advanced design phase.

Net Energy Metering

Net Energy Metering (NEM) in California is a billing arrangement that allows residential and commercial customers who generate their own electricity, primarily through solar photovoltaic (PV) systems, to receive credit for the surplus energy they contribute to the grid. This system is designed to incentivize the use of renewable energy sources by offsetting the cost of electricity consumption with the energy produced by these installations.

Under NEM, when a solar system generates more electricity than is consumed, the excess energy is sent back to the utility grid, and the customer earns credits. These credits can then be used to offset the cost of energy drawn from the grid when the solar system is not producing enough to meet the customer's demand, like during nighttime or cloudy days. The rules, rates, and credits under NEM can vary over time, with different iterations such as NEM 1, 2, and the latest NEM 3, each having specific regulations and compensation structures for solar energy production and exchange.

The transition from NEM 2 to NEM 3 in California, which was effective on April 14, 2023, introduced significant changes in the net metering policies for utility customers with photovoltaic (PV) systems. These changes impact several aspects, particularly the economics of energy arbitrage between PV system owners and the utility. Here is a summary of the key changes:

1) **Reduction in Export Rates:** Under NEM 3, there is a substantial reduction in the rates for excess electricity exported onto the grid by solar systems. This rate has been reduced by approximately 75%, thereby lowering the overall savings for home solar systems and increasing the payback period. This change is a shift from the traditional one-to-one offset of net metering policies, where the price of a kWh of electricity pushed onto the grid was equal to the price of a kWh pulled off the grid.
2) **Implementation of Electrification Rates:** Customers enrolling in NEM 3 are required to use electrification rates instead of regular Time-of-Use (TOU) rates. These electrification rates feature higher on-peak charges and lower off-peak charges, along with a fixed charge of $15 per month. The peak rate period remains from 4 pm to 9 pm.
3) **Export Compensation Based on Avoided Cost Calculator (ACC):** Export compensation under NEM 3 is determined by California's ACC, with specific export rates for every combination of Month, Hour, and Weekday or Weekend. The export value is lowest in the middle of the day when solar energy is abundant on the grid and highest during peak summer demand periods. Notably, the export rates are significantly lower than retail rates during the hours when PV systems are most productive (10 am – 3 pm). To maintain the financial viability of solar PV systems, customers in PG&E and SCE service territories receive an adder on top of the ACC rate, ranging between 2.2 and 9 cents depending on location and customer class.
4) **Shift to a Cost Avoidance System:** NEM 3 introduces a cost avoidance system for exported electricity. This system pays customers the lowest amount a company can pay under the Public Utility Regulatory Policies Act of 1978 (PURPA), which is significantly less than the typical retail rate. This results in customers receiving, on average, 75% less for the electricity they sell back to the grid, with rates varying by month and by hour.
5) **Grandfathering NEM 2 under NEM 3:** Under the recent NEM 3 policy in California, existing customers with a photovoltaic (PV) system installed under NEM 2 can retain the benefits and terms of their NEM 2 agreement, a process known as "grandfathering." However, these customers are restricted from replacing or adding capacity to their PV systems if they wish to maintain their NEM 2 status, as any significant modifications would require transitioning to the terms of NEM 3.

The Net Energy Metering (NEM) 3.0 policy introduces transformative changes, particularly enhancing the value of utilizing Battery Energy Storage Systems (BESS) for owners of solar power systems. A significant aspect of NEM 3.0 is the reduction in compensation rates for surplus electricity fed back into the grid by solar systems, now down to 75%. This adjustment shifts the financial dynamics, making it less lucrative to export excess solar energy to the grid. Instead, storing this surplus energy in a BESS and utilizing it when energy costs are higher becomes a more financially savvy approach.

The utility of BESS extends beyond merely optimizing the use of solar energy. It offers several additional advantages, such as providing backup power during utility blackouts, mitigating charges associated with demand peaks, and enabling energy arbitrage. Energy arbitrage under this system allows for the charging of BESS not only with excess solar energy but also with cheaper grid energy during low-cost periods. This stored energy can then be used in lieu of more expensive grid power at peak times, effectively reducing reliance on utility-supplied energy. Consequently, NEM 3.0 not only promotes more efficient use of solar energy but also broadens the scope of BESS applications, contributing to a more versatile and resilient energy management strategy.

Attachment

WRCOG Energy Resilience Plan 2.0 Community Resilience Center Feasibility Studies

AECOM

Community Resilience Center Feasibility Study

City of Beaumont

Albert A. Chatigny
Senior Community Recreation Center

February 2026

Delivering a better world

509

Introduction

In recent years, communities across the Inland Empire have experienced increasingly severe climate hazard conditions, including, but not limited to, wildfires, extreme heat, extreme winds, and flash flooding. Consequently, community resources and utility services continue to face frequent and impactful disruptions across Riverside County.

In 2023, the Western Riverside Council of Governments (WRCOG) was awarded a grant under the Integrated Climate Adaptation and Resiliency Program from the Governor's Office of Land Use and Climate Innovation to develop an *Energy Resilience Plan 2.0*. The grant project includes feasibility studies for Community Resilience Centers for WRCOG member agencies.

Community Resilience Center – Permanent community-serving facility equipped to support residents and coordinate essential resource distribution and services before, during, and after an emergency event

Distinct from an emergency shelter, a Community Resilience Center serves as a year-round resource hub that can be activated for response functions during emergency events. It is defined by the infrastructure and building components (e.g., backup power, air filtration, alternate communications), service functions (e.g., community gathering, social programming), and accessibility that support community resilience in both business-as-usual and emergency scenarios, typified in these prototypical modes of operation:

- Steady State – Acts in ordinary community-serving capacity (e.g., community center, senior center, fire station)
- Disruption (During Emergency Event) – Provides immediate relief, shelter, and access to resources for residents and community members
- Recovery (Post-Emergency) – Can serve as a central location for resource distribution, mutual aid and volunteer coordination, etc.

The Senior Community Recreation Center was selected by the City of Beaumont to be evaluated for its viability to serve as a Community Resilience Center. Feasibility assessment results are presented as follows:

- Site Profile
- Community Profile
- Facility Profile
- Gaps and Recommendations

This document is intended to serve the City of Beaumont with first step analysis in identifying an opportunity to improve community resilience. The *Energy Resilience Plan 2.0* provides further guidance on resilience strategies and implementation considerations.

From the Governor's Office of Land Use and Climate Innovation

As communities in California experience more frequent, prolonged, and severe impacts from climate change, communities and governments at all scales are developing strategies and implementing actions to build a climate- resilient future. However, many jurisdictions, especially under-resourced communities in California, lack the capacity, tools, guidance, and resources to effectively prepare for climate impacts.

The Adaptation Planning Grant Program addresses this capacity gap by providing funding to help fill planning needs, providing communities with the resources to identify climate resilience priorities, and supporting the development of climate resilience projects across the state. The Adaptation Planning Grant Program enables communities to climate risk and adaptation considerations into planning activities and prepare for climate readiness and resilience in the long term.

The Adaptation Planning Grant is part of the Integrated Climate Adaptation and Resiliency Program (ICARP) housed within the Governor's Office of Land Use and Climate Innovation (LCI). ICARP advances statewide climate adaptation and resilience by coordinating investments, partnerships, and climate science to ensure people, natural systems, and the built environment are protected, prepared, and thrive in the face of climate change.

Through direct and equity-focused investments and resources, ICARP helps build climate adapted and equitable communities in California, with a focus on solutions that address the impacts of climate change and reduce greenhouse gas emissions. ICARP works to advance these priorities across all levels of government by developing actionable science and research; providing guidance, tools, and technical assistance; and administering climate resilience-focused grant programs.

Learn more: https://lci.ca.gov/climate/icarp/

Site Profile

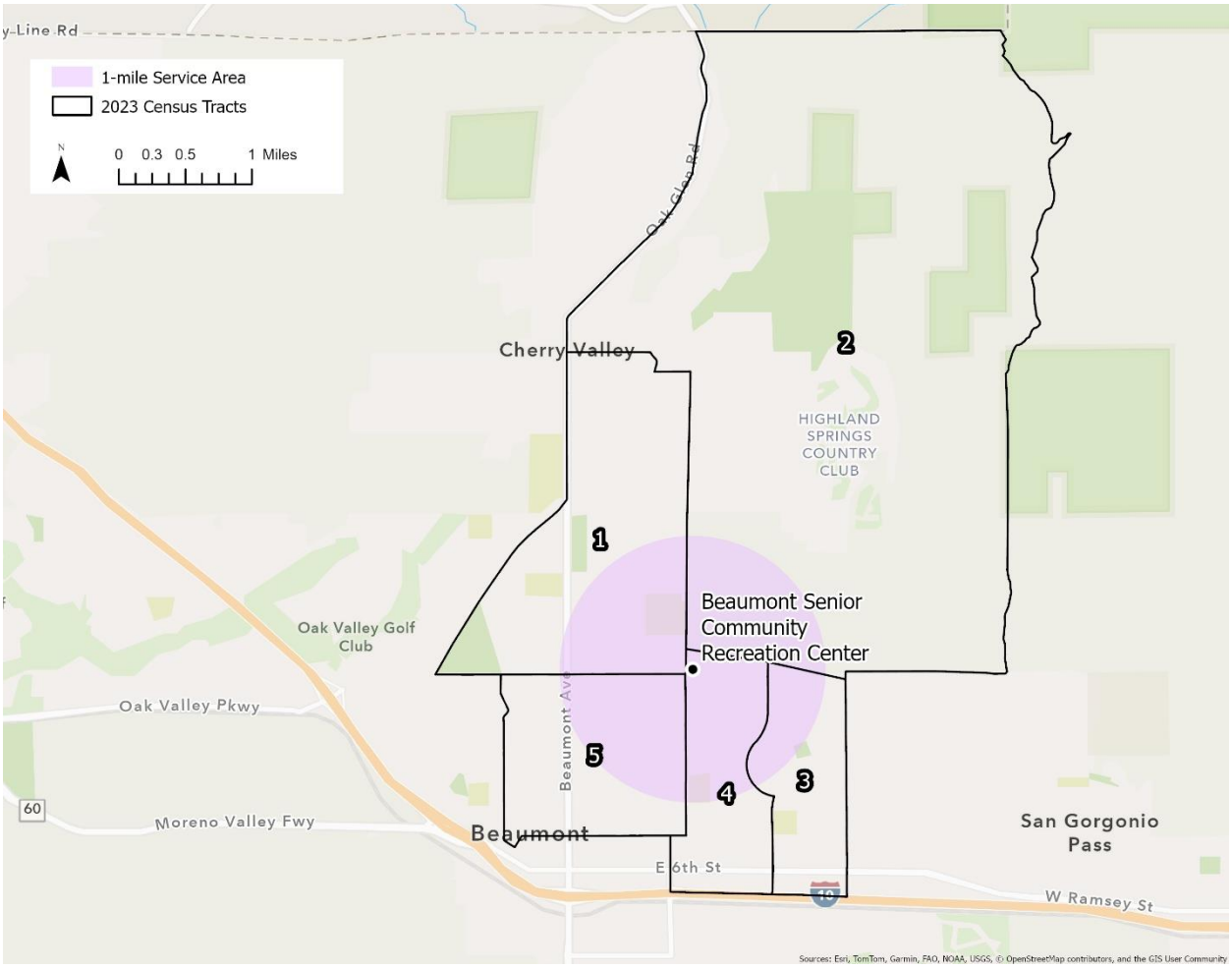


Figure 1. Site Location Map

The Senior Community Recreation Center is located in the northeast of the City of Beaumont within a residential neighborhood. For the purpose of the assessment, the service area was determined to be the area within a 1-mile radius of the site (shown in Figure 1). There are five census tracts that intersect with the service area and these were used to assess the site's climate vulnerability and the community's priority populations (See Table 1 for census tract IDs). However, the census tract boundaries go beyond the service area boundaries. Therefore, characteristics are provided for an area greater than the 1-mile radius from the site.

Table 1 provides the site's accessibility and vulnerability to climate hazards.

Table 1. Site Characteristics

Site Characteristics	Senior Community Recreation Center
Address	1310 Oak Valley Pkwy, Beaumont, CA 92223
Census Tract IDs (2023)	(1) 06065043807 (2) 06065043809 (3) 06065043818 (4) 06065043821 (5) 06065043900
Climate Vulnerability	**High/Medium Risk Climate Hazards *(one or more tracts above CVI 50th national vulnerability percentile[1])*:** Drought; Wildfire; Flooding **Site Facility in 100-year Floodplain:** No, but the 100-year floodplain/Flood Zone A does cross through the western side of the site lot. There is an existing stormwater channel in this area of the site.
Pedestrian Accessibility	**Percent of the Service Area within a 15 min Walk to the Facility[2]:** 40% **Major Network/Sidewalk Gaps:** There do not appear to be any major pedestrian network gaps to access or evacuate the site area. There is sidewalk along both sides of Oak Valley Pkwy and a yellow-striped crosswalk at the intersection of Oak Valley Pkwy and Cherry Ave in front of the facility for added pedestrian safety. There is a pedestrian trail to the south of the site with access to Anna Hause Elementary School. There is a private gated community to the northeast of the facility which limits pedestrian access from this direction.
Public Transit Accessibility	**Total Routes Serving the Site Area:** 5 transit routes **Total Stops in the Site Area:** 93 transit stops **Distance to Nearest Stop:** Around 0.10 miles to each of the closest two transit stops that serve the City of Beaumont Route 352, one stop on Cherry Ave to the west of the facility and one on Oak Valley Pkwy to the east. Pedestrian travel on sidewalks is possible for a majority of the route to transit stops.
Proximity to Evacuation Routes or Major Highways	**Proximity to Interstate 10:** ~2.5 miles using Oak Valley Pwky **Located on an Evacuation Route** (Oak Valley Pkwy)

[1] The Climate Vulnerability Index (CVI) uses 2010 Census tracts. https://map.climatevulnerabilityindex.org/map/cvi_overall/usa?mapBoundaries=Tract&mapFilter=0&reportBoundaries=Tract&geoContext=State

[2] Walksheds were developed in Urban Footprint and use parcel areas, excluding rights-of-way, to calculate the percent of the service area that is within a 15-minute walk from the facility. Learn more about Urban Footprint software: https://urbanfootprint.com/

Community Profile

The median household incomes of tracts in the surrounding community are on average lower compared to the State's Median Household Income (MHI). None of the census tracts that intersect with the site area are a designated SB 535 Disadvantaged Community determined by the top 25% of CalEnviroScreen 4.0 percentile scores.[3] Table 2 provides the surrounding population size and priority population factors for each tract compared to state averages, noting in red when census tracts are below the state average and noting in green when census tracts are above the state average.

Table 2. Community Characteristics

Characteristics	Senior Community Recreation Center						
Surrounding Population Size[4]	15,295						
Priority Population Factors	**Census Tracts** 1	2	3	4	5	**Average**	**State Average**
Disabled[5]	12.99%	13.63%	8.71%	12.40%	10.93%	**11.73%**	**11.65%**
Chronic Conditions[6]	38th percentile	46th percentile	55th percentile	49th percentile	33rd percentile	**0 of 5 'Least Healthy' Tracts**	**'Least Healthy' below 25th percentile statewide**
Limited English[7]	8.15%	4.47%	7.75%	9.28%	11.18%	**8.16%**	**17.08%**
Children Under 5[8]	11.99%	6.32%	5.5%	10.83%	7.22%	**8.37%**	**5.44%**
Elderly Over 75[9]	5.67%	10.75%	4.11%	4.04%	2.41%	**5.40%**	**6.66%**
Pregnant People[10]	6.30%	11.30%	0.00%	15.11%	8.30%	**8.20%**	**4.86%**
Low Income[11]	$88,312	$99,534	$143,352	$81,518	$69,201	**$96,383**	**$104,103**
No Vehicle Access[12]	2.86%	2.75%	1.78%	3.25%	6.35%	**3.40%**	**7.15%**
Homelessness[13]	In January 2024 the Riverside City and County CoC had a total of 4,249 homeless persons, 57% of which were not sheltered by emergency shelter or transitional housing. Comparatively, 34% of the state of California's homeless population was not sheltered by emergency shelter or transitional housing.						

[3] State of California OEHHA. SB 535 Disadvantaged Communities. https://oehha.ca.gov/calenviroscreen/sb535
[4] The surrounding population size was calculated using 2020 Census blocks within the 1-mile service area. Some of the blocks included in this calculation go beyond the service area boundary. Blocks that intersect with the service area but do not have a significant portion of the block within the service area were excluded.
[5] ACS 5-year 2019-2023 Census: Disabled Populations
[6] Healthy Places Index (HPI)
[7] ACS 5-year 2019-2023 Census: Language Spoken at Home for the Population 5 Years and Over
[8] ACS 5-year 2019-2023 Census: Sex & Age
[9] ACS 5-year 2019-2023 Census: Sex & Age
[10] ACS 5-year 2019-2023 Census: Women 15 to 50 Years Who Had a Birth in the Past 12 Months
[11] ACS 5-year 2019-2023 Census: Median Household Income
[12] ACS 5-year 2019-2023 Census: Households with No Vehicle
[13] The U.S. Department of Housing and Urban Development reports on homelessness from point-in-time information by Continuums of Care (CoCs) that provides counts for sheltered and unsheltered homeless persons by household type and subpopulation. For more information see https://www.hudexchange.info/programs/coc/coc-homeless-populations-and-subpopulations-reports/.

Facility Profile

The Albert A. Chatigny Senior Community Recreation Center features assets such as basketball courts, meeting rooms, a playground, and a senior center that hosts activities and provides information and assistance for older adults, their families, and persons with disabilities.[14] The following tables provide an overview of the results of the facility evaluation for criteria that were developed under the USDN five foundational areas of resilience hubs: Communications, Building & Landscape, Power, Operations & Maintenance, and Services & Programming.[15] Green rows indicate criteria is met, and red rows indicate criteria is not met.

Communications

Broadband Access	Yes
Wired-Phone / Satellite Phone	*Does the facility have a wired or satellite phone available?* Yes, have a phone that uses ethernet instead of the cell network
Ability to Charge Communication Devices / Medical Devices	Yes

Building & Landscape

Heating and Cooling	*How old is the existing HVAC system? When is the planned/estimated replacement?* The existing units are from 2008 and the units have planned replacement starting in 2031.
	Does the unit have an air filtration system of at least MERV 13? Yes
Potable Water Sources	Yes
Water Resupply Methods/ Plans	No
Resilience to Climate Hazards	*Was the facility built to withstand climate hazards that may impact the site? [Flooding, Drought, Wildfire]* The site has water conservation measures such as low flow toilets and drought tolerant landscaping. There is a stormwater channel for flood control located to the south of the building. The facility does not keep any mechanical/electrical equipment below ground; most are located on the roof.
Rainwater Harvesting / Water Capture and Filtration	No
Space for Community Garden	Yes, have been exploring creating a community garden that is tied to the Senior Center.

[14] City of Beaumont. *Facilities.* https://www.beaumontca.gov/Facilities/Facility/Details/-4
[15] USDN. *Resilience Hubs: Five Foundational Areas*. Resilience Hub Five Foundational Areas

Power

Power Infrastructure	The site has an existing standby emergency generator and associated infrastructure in place. Provided information did not indicate any critical limitation(s) of existing facility circuitry prohibitive to microgrid development. Available roof and parking lot space (i.e., carport) for photovoltaic array(s) is adequate for onsite generation capacity sufficient to meet or exceed present-day demand. In short, the site is "microgrid-ready." Details available in accompanying *Microgrid Feasibility Study*.
Back-Up Power	Yes

Operations & Maintenance

Emergency Capacity	Yes, have an agreement with Red Cross for the gym to be used for overnight shelter, staging, and other needs during an evacuation. During an evacuation can provide charging stations, overnight shelter, and food distribution (the facility has a full commercial kitchen).
Emergency Plan	Yes, citywide plan that includes the facility
Security	*Does the facility have a functioning alarm system?* Yes
	Does the facility have secure doors? Yes
	Does the facility have motion-activated lights in areas such as hallways and bathrooms? Yes
ADA Assessment	
Gross Floor Area	25,000 sq ft
No. of people assumed	300
Criteria	Evaluation Notes
Route	**Meets accessibility needs:** A continuous, unobstructed path with gentle or no slopes, providing access from public spaces to the building.
Parking	**Meets accessibility needs:** Site provides an adequate number of accessible parking spaces with properly sized access aisles.
Building entrance	**Meets accessibility needs:** Accessible main entrance or signage is provided to accessible entry.
Restroom clearances	**Meets accessibility needs:** Restrooms include sufficient turning space, and door swings meet accessibility requirements.
Restroom fixture	**Meets accessibility needs:** Fixtures meet accessibility clearance and mounting height requirements.

Interior circulation	**Meets accessibility needs:** Interior pathways are unobstructed.
Multi-story accessibility	**Meets accessibility needs** - All levels of the building are accessible via an elevator or lift.

Services & Programming

Educational Programs	• Youth classes/programming
Recreation & Wellness	• Youth and adult sports leagues
Programming for Seniors	• Senior meals • Senior programming
Emergency Response Training	• Regular training for day-to-day emergencies, but do not have staff training for operating as an emergency center.
Partnerships	• Red Cross for evacuations • FSA – Senior Meal Program • County IT – Tech on Wheels • Non-profit sports leagues use the facility • School Districts use the facility • Rotary groups meet at facility • CalFire hosts meetings/town halls at the facility

Gaps and Recommendations

Site Access

The site is served by public transit, sidewalks, and roadways making the site accessible for populations using a variety of modes within the City of Beaumont. The City of Beaumont bus Route 353 has stops located on Cherry Ave and Oak Valley Pwky less than a quarter of a mile from the Senior Community Recreation Center. Sidewalks in the area appear to be in good condition and provide pedestrian access from multiple directions, including to transit stops and a pedestrian trail. The facility is located on an evacuation route that connects to Interstate 10.

To the northeast of the facility, vehicle and pedestrian access is restricted by a private gated community. The facility could consider coordinating with the private community to allow for gates to remain open during and after an emergency to allow flow of traffic and increase access to the site.

Priority Population Considerations

While the census data shows that the service area's average percent of the population that is disabled is greater the state average, the types of disabilities are not known. This assessment focused on the accessibility (ADA compliance) of the facility itself. The facility can coordinate with the local transit or rideshare provider for accessible transportation to and from the facility and provide back-up power for those who use medical equipment that requires electricity. The facility may need to work with the City of Beaumont to review sidewalk accessibility, as well as conduct outreach with residents to evaluate additional accessibility needs.

The average percentage of children under five in the service area is greater than the state average, meaning there may be more families with young children and infants using the facility during an emergency. To address the needs of children and their families during and after an emergency, the facility could provide childcare services and mental health services focused on trauma support for children during and after an emergency.

The average percentage of women 15 to 50 years who had a birth in the past 12 months in the service area is greater than the state average, meaning there may be more pregnant people using the facility during an emergency. To address the needs of this population, the facility could integrate maternal and child health considerations into emergency plans, provide basic medical services at the facility during and after an emergency, and coordinate with public health agencies and healthcare providers to provide supplies for infant feeding and educational resources for new parents.[16] It is also important to consider if the facility has adequate access to evacuation routes that can connect to a hospital in the case of a pregnancy occurring during or after an emergency. The Senior Community Recreation Center is located on an evacuation route that can provide access to the interstate and local medical facilities.

The average median household income in the service area tracts is lower than the state's. To address the needs of lower-income communities during and after an emergency, the facility can provide services for logistical support for communication with recovery agencies and insurance companies. Additionally, lower-income populations can feel especially stressed about financial planning and providing basic resources for themselves and their family after a disaster. The facility could consider offering or coordinating mental health services for these populations.

Although data on homeless persons is provided at the regional level, homelessness is best understood locally. The facility may consider if there is a visible presence of homeless persons

[16] U.S. Center for Disease Control. *Reproductive Health – Emergency Preparedness and Response Tools and Resources.* https://www.cdc.gov/reproductive-health/php/emergency-tools/index.html

in the service area of the facility, if the population seems to be growing, and if the facility has previously been a resource for homeless persons. This population may need additional support and services when sheltered during an emergency. Strategies to support this population that the facility can consider include coordination with local homeless shelters for disaster preparedness, understanding the capacity of homeless persons in the area the facility may need to support, and providing mental health and medical services.[17]

Building Resilience Checklist

The site area is vulnerable to drought, wildfires, and flooding. The following are suggestions for the facility to build resilience against these hazards.

Drought:

☐ Water conservation measures such as efficient plumbing fixtures and low-flow toilets

☐ Native landscaping and xeriscaping

☐ Recycled water system

Wildfire:

☐ Proper HVAC air filtration for internal air quality (wildfire smoke)

☐ Fire resistant construction that uses non-combustible or fire-resistant building materials for renovations or reconstruction

☐ Fire-resistant plants used in landscaping

Flooding:

☐ Wet floodproofing solutions – engineered flood vents and water-resistant building materials

☐ Dry floodproofing solutions – flood gates, backflow preventers on drains, sealing openings in walls and foundations, sump pumps, and waterproof enclosures

☐ Site perimeter floodproofing – sand bags, water-inflated tube systems and flood panels

☐ Elevated mechanical and electrical equipment to the roof or other areas above the flood level

☐ Stormwater management solutions – permeable pavers, bioswales, and green roofs

Facility Accessibility & Infrastructure

ADA Compliance

All ADA assessment criteria are met for the Beaumont Senior Community Recreation Center. There are no further recommendations for the facility to meet compliance. This ADA assessment is based on the building's intended use as defined by its code designation. Additional investigations and requirements may be necessary to accommodate emergency lodging, bathing, and waste disposal, as determined by the authority having jurisdiction.

[17] U.S. Housing and Development. *Disaster Recovery – Homelessness Toolkit.*
https://files.hudexchange.info/resources/documents/DR-H-Preparedness-Checklist-Shelter-and-Services.pdf

Facility Infrastructure

To support the facility to act as a community resilience center during and after an emergency, the facility can:

- Plan for the storage of and stock a sufficient amount of water resupply in case of a disruption to potable water systems.
- Assess the feasibility of adding a rain garden or capture and filtration system to the facility.
- Provide staff training for facility operations during an emergency using resources such as those provided in the USDN Resilience Hubs Guidance (pg.51).

Facility Operations & Disaster Preparedness

The community resilience center staff and volunteers can take steps to integrate processes and training that support the continued operation of the community resilience center in all operating conditions: normal operations, during an event, and after an event. Along with having a facility emergency plan, additional disaster preparedness strategies include the following:

- Determine appropriate and functional communication channels with the community to notify them the community resilience center is open, alert them of emergency updates, coordinate resources, and share general information.
- Identify key personnel and what role they will have in each of the operating modes.
- Identify and provide training for key personnel to increase preparedness and knowledge.
- Identify and provide training for community members to increase community adaptive capacity.
- Identify funding and partnerships to support key personnel in operating the community resilience center.

Additional Resources

Community resilience and disaster preparedness are broad topics with many detailed best practices and approaches. In addition to some key strategies summarized above, the following resources provide tools and guidance to prepare for disaster and build community resilience:

- Bay Localize, 2020. *Community Resilience Toolkit* (Link)
- Central Coast Climate Collaborative, 2025. What is a Community Resilience Hub? (Link)
- District of Columbia Department of Energy and Environment, 2025. Community Resilience Hubs (Link)
- U.S. Department of Homeland Security, 2025. *People with Disabilities* (Link)
- Urban Sustainability Directors Network, 2017. *Guide to Equitable, Community-Driven Climate Preparedness Planning* (Link)
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AECOM

Community Resilience Center Feasibility Study

City of Canyon Lake

City Hall

February 2026

Delivering a better world

Introduction

In recent years, communities across the Inland Empire have experienced increasingly severe climate hazard conditions, including, but not limited to, wildfires, extreme heat, extreme winds, and flash flooding. Consequently, community resources and utility services continue to face frequent and impactful disruptions across Riverside County.

In 2023, the Western Riverside Council of Governments (WRCOG) was awarded a grant under the Integrated Climate Adaptation and Resiliency Program from the Governor's Office of Land Use and Climate Innovation to develop an *Energy Resilience Plan 2.0*. The grant project includes feasibility studies for Community Resilience Centers for WRCOG member agencies.

Community Resilience Center – Permanent community-serving facility equipped to support residents and coordinate essential resource distribution and services before, during, and after an emergency event

Distinct from an emergency shelter, a Community Resilience Center serves as a year-round resource hub that can be activated for response functions during emergency events. It is defined by the infrastructure and building components (e.g., backup power, air filtration, alternate communications), service functions (e.g., community gathering, social programming), and accessibility that support community resilience in both business-as-usual and emergency scenarios, typified in these prototypical modes of operation:

- Steady State – Acts in ordinary community-serving capacity (e.g., community center, senior center, fire station)
- Disruption (During Emergency Event) – Provides immediate relief, shelter, and access to resources for residents and community members
- Recovery (Post-Emergency) – Can serve as a central location for resource distribution, mutual aid and volunteer coordination, etc.

The Canyon Lake City Hall was selected by the City of Canyon Lake to be evaluated for its viability to serve as a Community Resilience Center. Feasibility assessment results are presented as follows:

- Site Profile
- Community Profile
- Facility Profile
- Gaps and Recommendations

This document is intended to serve the City of Canyon Lake with first step analysis in identifying an opportunity to improve community resilience. The *Energy Resilience Plan 2.0* provides further guidance on resilience strategies and implementation considerations.

From the Governor's Office of Land Use and Climate Innovation

As communities in California experience more frequent, prolonged, and severe impacts from climate change, communities and governments at all scales are developing strategies and implementing actions to build a climate- resilient future. However, many jurisdictions, especially under-resourced communities in California, lack the capacity, tools, guidance, and resources to effectively prepare for climate impacts.

The Adaptation Planning Grant Program addresses this capacity gap by providing funding to help fill planning needs, providing communities with the resources to identify climate resilience priorities, and supporting the development of climate resilience projects across the state. The Adaptation Planning Grant Program enables communities to climate risk and adaptation considerations into planning activities and prepare for climate readiness and resilience in the long term.

The Adaptation Planning Grant is part of the Integrated Climate Adaptation and Resiliency Program (ICARP) housed within the Governor's Office of Land Use and Climate Innovation (LCI). ICARP advances statewide climate adaptation and resilience by coordinating investments, partnerships, and climate science to ensure people, natural systems, and the built environment are protected, prepared, and thrive in the face of climate change.

Through direct and equity-focused investments and resources, ICARP helps build climate adapted and equitable communities in California, with a focus on solutions that address the impacts of climate change and reduce greenhouse gas emissions. ICARP works to advance these priorities across all levels of government by developing actionable science and research; providing guidance, tools, and technical assistance; and administering climate resilience-focused grant programs.

Learn more: https://lci.ca.gov/climate/icarp/

Site Profile

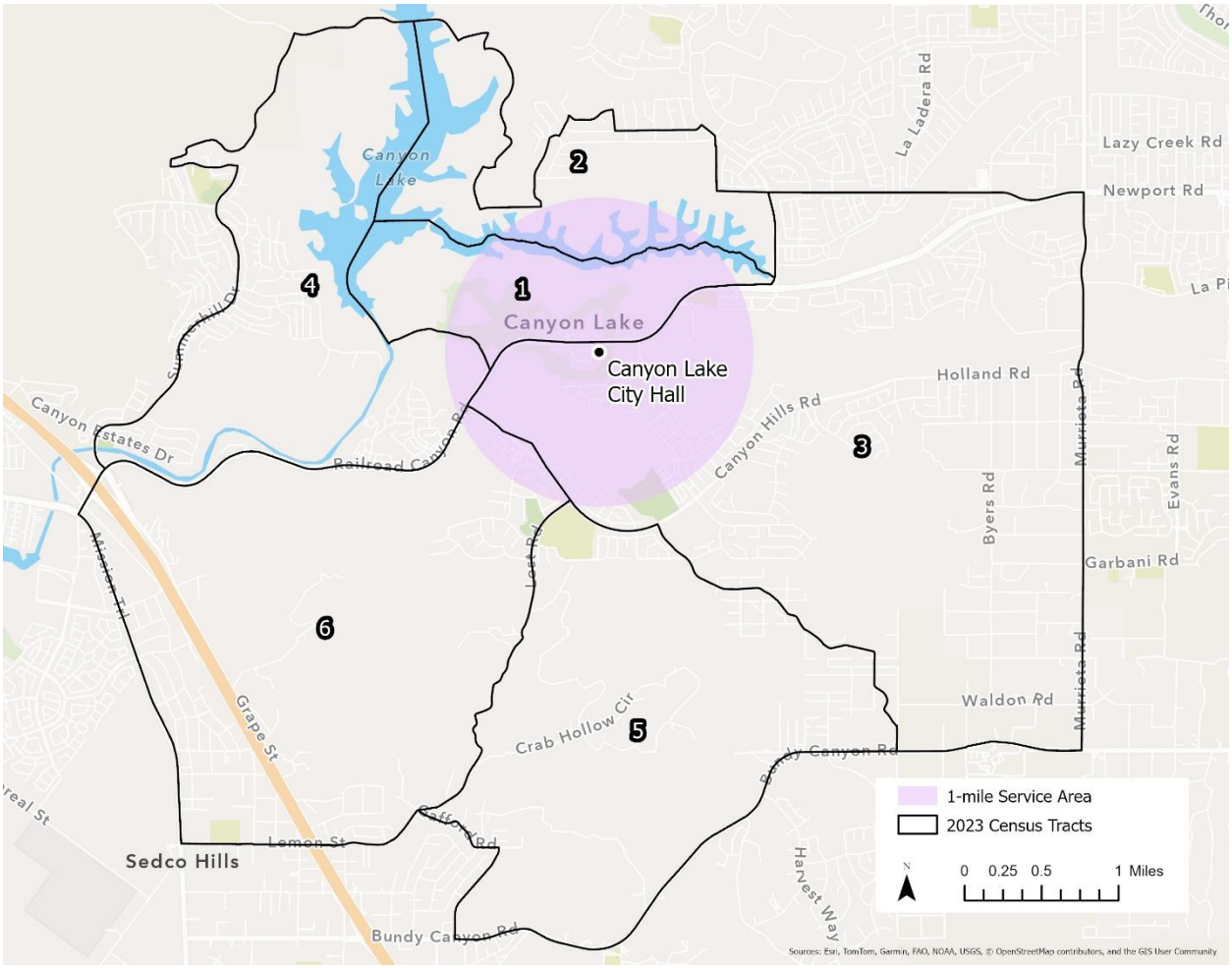


Figure 1. Site Location Map

The Canyon Lake City Hall is located south of Canyon Lake in the Canyon Lake Towne Center off Railroad Canyon Rd. For the purpose of the assessment, the service area was determined to be the area within a 1-mile radius of the site (shown in Figure 1). There are six census tracts that intersect with the service area and these were used to assess the site's climate vulnerability and the community's priority populations (See Table 1 for census tract IDs). However, the census tract boundaries go beyond the service area boundaries. Therefore, characteristics are provided for an area greater than the 1-mile radius from the site.

Table 1 provides the site's accessibility and vulnerability to climate hazards.

Table 1. Site Characteristics

Site Characteristics	Canyon Lake City Hall
Address	31516 Railroad Canyon Rd, Canyon Lake, CA 92587
Census Tract IDs (2023)	(1) 06065042714 (2) 06065042716 (3) 06065042733 (4) 06065042748 (5) 06065043274 (6) 06065046404
Climate Vulnerability	**High/Medium Risk Climate Hazards *(one or more tracts above CVI 50th national vulnerability percentile[1])*:** Drought; Wildfire; Flooding **Site Facility in 100-year Floodplain:** No
Pedestrian Accessibility	**Percent of the Service Area within a 15 min Walk to the Facility[2]:** 28% **Major Network/Sidewalk Gaps:** There is pedestrian access to the north of City Hall using the sidewalk along Railroad Canyon Rd. However, directly south of City Hall and the Canyon Lake Towne Center are part of the Canyon Lake Golf & Country Club course and a private residential road that blocks public access. Additionally, to the south the elevation rises to form Culp Hill blocking direct access to City Hall for residents in neighborhoods off Canyon Hills Rd.
Public Transit Accessibility	**Total Routes Serving the Site Area:** 0 transit routes **Total Stops in the Site Area:** 0 transit stops **Distance to Nearest Stop:** 4 miles to the closest transit stop in Menifee or 3.5 miles to the closest transit stop in Lake Elsinore. There is no transit service in the City of Canyon Lake.
Proximity to Evacuation Routes or Major Highways	**Proximity to Interstate 15:** ~3 miles using Railroad Canyon Rd **Proximity to Interstate 215:** ~5 miles using Railroad Canyon Rd and Newport Rd **Close Proximity to Evacuation Routes:** ~0.08 miles to Railroad Canyon Rd

[1] The Climate Vulnerability Index (CVI) uses 2010 Census tracts. https://map.climatevulnerabilityindex.org/map/cvi_overall/usa?mapBoundaries=Tract&mapFilter=0&reportBoundaries=Tract&geoContext=State

[2] Walksheds were developed in Urban Footprint and use parcel areas, excluding rights-of-way, to calculate the percent of the service area that is within a 15-minute walk from the facility. Learn more about Urban Footprint software: https://urbanfootprint.com/

Community Profile

The median household incomes of tracts in the surrounding community are on average higher compared to the State's Median Household Income (MHI). Additionally, none of the census tracts that intersect with the service area are a designated SB 535 Disadvantaged Community determined by the top 25% of CalEnviroScreen 4.0 percentile scores. [3] Table 2 provides the surrounding population size and priority population factors for each tract compared to state averages, noting in red when census tracts are below the state average and noting in green when census tracts are above the state average.

Table 2. Community Characteristics

Characteristics	Canyon Lake City Hall							
Surrounding Population Size[4]	10,101							
	Census Tracts							
Priority Population Factors	**1**	**2**	**3**	**4**	**5**	**6**	**Average**	**State Average**
Disabled[5]	17.77%	8.88%	11.14%	12.09%	8.45%	13.59%	**11.99%**	**11.65%**
Chronic Conditions[6]	68th percentile	59th percentile	49th percentile	45th percentile	43rd percentile	24th percentile	**1 of 6 'Least Healthy' Tracts**	**'Least Healthy' below 25th percentile statewide**
Limited English[7]	0.28%	2.28%	6.85%	6.67%	10.44%	18.01%	**7.42%**	**17.08%**
Children Under 5[8]	2.15%	7.84%	8.02%	3.19%	2.18%	10.10%	**5.58%**	**5.44%**
Elderly Over 75[9]	9.42%	7.36%	1.93%	1.51%	1.09%	5.48%	**4.47%**	**6.66%**
Pregnant People[10]	0.00%	8.17%	9.17%	1.31%	3.5%	5.89%	**4.70%**	**4.86%**
Low Income[11]	$114,191	$126,464	$150,262	$134,638	$106,626	$84,709	**$119,481**	**$104,103.66**
No Vehicle Access[12]	4.73%	2.01%	3.40%	3.02%	6.86%	1.61%	**3.60%**	**7.15%**
Homelessness[13]	In January 2024 the Riverside City and County CoC had a total of 4,249 homeless persons, 57% of which were not sheltered by emergency shelter or transitional housing. Comparatively, 34% of the state of California's homeless population was not sheltered by emergency shelter or transitional housing.							

[3] State of California OEHHA. SB 535 Disadvantaged Communities. https://oehha.ca.gov/calenviroscreen/sb535
[4] The service population was calculated using 2020 Census blocks within the 1-mile service area. Some of the blocks included in this calculation go beyond the service area boundary. Blocks that intersect with the service area but do not have a significant portion of the block within the service area were excluded.
[5] ACS 5-year 2019-2023 Census: Disabled Populations
[6] Healthy Places Index (HPI)
[7] ACS 5-year 2019-2023 Census: Language Spoken at Home for the Population 5 Years and Over
[8] ACS 5-year 2019-2023 Census: Sex & Age
[9] ACS 5-year 2019-2023 Census: Sex & Age
[10] ACS 5-year 2019-2023 Census: Women 15 to 50 Years Who Had a Birth in the Past 12 Months
[11] ACS 5-year 2019-2023 Census: Median Household Income
[12] ACS 5-year 2019-2023 Census: Households with No Vehicle
[13] The U.S. Department of Housing and Urban Development reports on homelessness from point-in-time information by Continuums of Care (CoCs) that provides counts for sheltered and unsheltered homeless persons by household type and subpopulation. For more information see https://www.hudexchange.info/programs/coc/coc-homeless-populations-and-subpopulations-reports/.

Facility Profile

The Canyon Lake City Hall is located in the Canyon Lake Towne Center and is where City Council hosts meetings and other government services take place. The following tables provide an overview of the results of the facility evaluation for criteria that were developed under the USDN five foundational areas of resilience hubs: Communications, Building & Landscape, Power, Operations & Maintenance, and Services & Programming.[14] Green rows indicate criteria is met, and red rows indicate criteria is not met.

Communications

Broadband Access	Yes
Wired-Phone / Satellite Phone	*Does the facility have a wired or satellite phone available?* Unknown at this time
Ability to Charge Communication Devices / Medical Devices	Yes

Building & Landscape

Heating and Cooling	*How old is the existing HVAC system? When is the planned/estimated replacement?* Two of the four systems were replaced in April 2025
	Does the unit have an air filtration system of at least MERV 13? Unknown at this time
Potable Water Sources	Yes
Water Resupply Methods/ Plans	Yes
Resilience to Climate Hazards	*Was the facility built to withstand climate hazards that may impact the site? [Flooding, Drought, Wildfire]* Unknown at this time
Rainwater Harvesting / Water Capture and Filtration	No, do not have a capture and filtration system but do have the ability for one to be installed onsite
Space for Community Garden	No

Power

Power Infrastructure	The site has an existing standby emergency generator and associated infrastructure in place. Provided information was insufficient to determine limitation of existing facility circuitry, if any. That said, available roof space for photovoltaic array(s) is adequate for onsite generation capacity sufficient to meet or exceed present-day demand. In short, the site is “microgrid-ready.” Details available in accompanying *Microgrid Feasibility Study*.

[14] USDN. *Resilience Hubs: Five Foundational Areas*. Resilience Hub Five Foundational Areas

Back-Up Power	Yes

Operations & Maintenance

Emergency Capacity	The facility is not currently used as an evacuation or emergency shelter
Emergency Plan	No
Security	*Does the facility have a functioning alarm system?* Yes
	Does the facility have secure doors? Yes
	Does the facility have motion-activated lights in areas such as hallways and bathrooms? Yes
ADA Assessment	
Gross Floor Area	146 sq ft.
No. of people assumed	85; 110 without furniture
Criteria	Evaluation Notes
Route	**Meets accessibility needs:** A continuous, unobstructed path with gentle or no slopes, providing access from public spaces to the building.
Parking	**Meets accessibility needs:** Site provides an adequate number of accessible parking spaces with properly sized access aisles.
Building entrance	**Meets accessibility needs:** Accessible main entrance or signage is provided to accessible entry.
Restroom clearances	**To be verified:** Restrooms should include sufficient turning space, and door swings should meet accessibility requirements.
Restroom fixture	**To be verified:** Fixtures should meet accessibility clearance and mounting height requirements.
Interior circulation	**To be verified:** Interior pathways should be unobstructed.
Multi-story accessibility	**To be verified:** All levels of the building should be accessible via an elevator or lift.

Services & Programming

Educational Programs	• None identified
Recreation & Wellness	• None identified

Programming for Seniors	• None identified
Emergency Response Training	• CERT Trainings • Training for CPR/First Aid provided to City staff
Partnerships	• EVMWD provides water

Gaps and Recommendations

Site Access

There is no public transit service in the City of Canyon Lake to allow the community to take transit to the Canyon Lake City Hall during or after an emergency. To address this gap the city can consider how those without a vehicle may access the City Hall during or after an emergency and determine if carpooling or a rideshare services could provide adequate access.

To address the gap in pedestrian and vehicle access south of City Hall due to private property and geological barriers, the city can consider if the extra time it takes to access the site for those communities means a second community resilience center or an alternative location for the city's community resilience center is needed.

Priority Population Considerations

While the census data shows that the service area's average percent of the population that is disabled is greater the state average, the types of disabilities are not known. This assessment focused on the accessibility (ADA compliance) of the facility itself. The facility can coordinate with the local transit or rideshare provider for accessible transportation to and from the facility and provide back-up power for those who use medical equipment that requires electricity. The facility may need to work with the City of Canyon Lake to review sidewalk accessibility, as well as conduct outreach with residents to evaluate additional accessibility needs.

The average percentage of children under five in the service area is greater than the state average, meaning there may be more families with young children and infants using the facility during an emergency. To address the needs of children and their families during and after an emergency, the facility could provide childcare services and mental health services focused on trauma support for children during and after an emergency.

Although data on homeless persons is provided at the regional level, homelessness is best understood locally. The facility may consider if there is a visible presence of homeless persons in the service area of the facility, if the population seems to be growing, and if the facility has previously been a resource for homeless persons. This population may need additional support and services when sheltered during an emergency. Strategies to support this population that the facility can consider include coordination with local homeless shelters for disaster preparedness, understanding the capacity of homeless persons in the area the facility may need to support, and providing mental health and medical services.[15]

[15] U.S. Housing and Development. *Disaster Recovery – Homelessness Toolkit.*
https://files.hudexchange.info/resources/documents/DR-H-Preparedness-Checklist-Shelter-and-Services.pdf

Building Resilience Checklist

The site area is vulnerable to drought, wildfires, and flooding. The following are suggestions for the facility to build resilience against these hazards.

Drought:

☐ Water conservation measures such as efficient plumbing fixtures and low-flow toilets

☐ Native landscaping and xeriscaping

☐ Recycled water system

Wildfire:

☐ Proper HVAC air filtration for internal air quality (wildfire smoke)

☐ Fire resistant construction that uses non-combustible or fire-resistant building materials for renovations or reconstruction

☐ Fire-resistant plants used in landscaping

Flooding:

☐ Wet floodproofing solutions – engineered flood vents and water-resistant building materials

☐ Dry floodproofing solutions – flood gates, backflow preventers on drains, sealing openings in walls and foundations, sump pumps, and waterproof enclosures

☐ Site perimeter floodproofing – sand bags, water-inflated tube systems and flood panels

☐ Elevated mechanical and electrical equipment to the roof or other areas above the flood level

☐ Stormwater management solutions – permeable pavers, bioswales, and green roofs

Facility Accessibility & Infrastructure

ADA Compliance

An ADA assessment could not be fully completed for the Canyon Lake City Hall. A full assessment can be made after review of the second level building plan. This ADA assessment is based on the building's intended use as defined by its code designation. Additional investigations and requirements may be necessary to accommodate emergency lodging, bathing, and waste disposal, as determined by the authority having jurisdiction.

Facility Infrastructure

To support the facility to act as a community resilience center during and after an emergency, the facility can:

- Install adequate air filtration of at least MERV 13 or higher to the HVAC system to maintain indoor air quality in the event of wildfire smoke in the area, if the facility is found to not have proper air filtration.
- Assess the feasibility of adding a rain garden or capture and filtration system to the facility.
- Consider the feasibility of partnering with a nearby HOA or POA to create a community garden that can build community and provide fresh food.
- Develop an emergency plan for the facility and understand the capacity the facility has to serve the community during an emergency, whether that be as an emergency shelter or as a hub for sharing information and coordination.

Facility Operations & Disaster Preparedness

The community resilience center staff and volunteers can take steps to integrate processes and training that support the continued operation of the community resilience center in all operating conditions: normal operations, during an event, and after an event. Along with having a facility emergency plan, additional disaster preparedness strategies include the following:

- Determine appropriate and functional communication channels with the community to notify them the community resilience center is open, alert them of emergency updates, coordinate resources, and share general information.
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Additional Resources

Community resilience and disaster preparedness are broad topics with many detailed best practices and approaches. In addition to some key strategies summarized above, the following resources provide tools and guidance to prepare for disaster and build community resilience:

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AECOM

Community Resilience Center Feasibility Study

City of Corona

Corporation Yard

February 2026

Delivering a better world

Introduction

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- Steady State – Acts in ordinary community-serving capacity (e.g., community center, senior center, fire station)
- Disruption (During Emergency Event) – Provides immediate relief, shelter, and access to resources for residents and community members
- Recovery (Post-Emergency) – Can serve as a central location for resource distribution, mutual aid and volunteer coordination, etc.

The Corona Fire Department Headquarters/Corporation Yard was selected by the City of Corona to be evaluated for its viability to serve as a Community Resilience Center. Feasibility assessment results are presented as follows:

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- Community Profile
- Facility Profile
- Gaps and Recommendations

This document is intended to serve the City of Corona with first step analysis in identifying an opportunity to improve community resilience. The *Energy Resilience Plan 2.0* provides further guidance on resilience strategies and implementation considerations.

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Site Profile

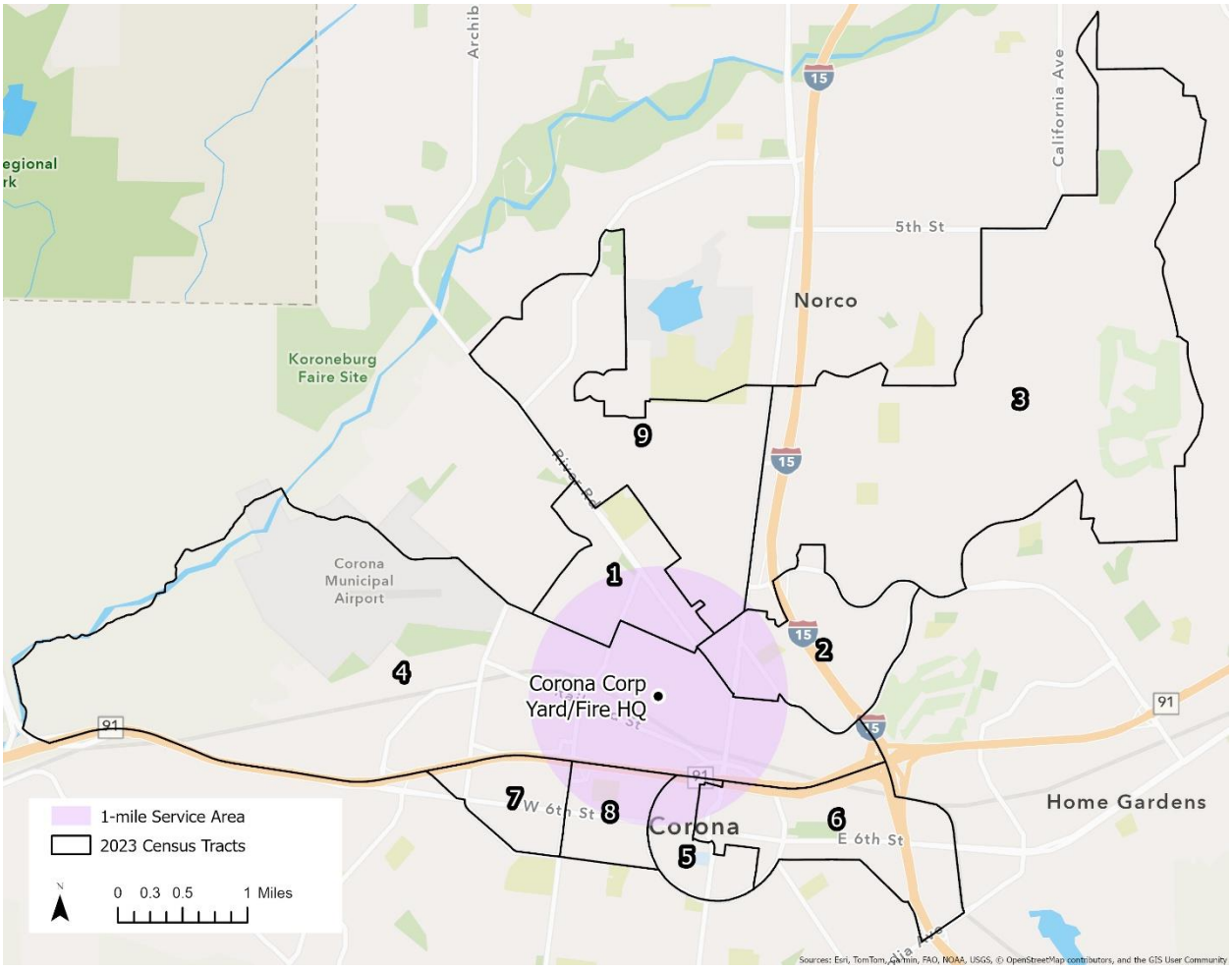


Figure 1. Site Location Map

The Corona Fire Department Headquarters/Corporation Yard is located in the north of the City of Corona in an industrial area near the intersection of State Highway 91 and Interstate-15. For the purpose of the assessment, the service area was determined to be the area within a 1-mile radius of the site (shown in Figure 1). There are nine census tracts that intersect with the service area and these were used to assess the site's climate vulnerability and the community's priority populations (See Table 1 for census tract IDs). However, the census tract boundaries go beyond the service area boundaries. Therefore, characteristics are provided for an area greater than the 1-mile radius from the site.

Table 1 provides the site's accessibility and vulnerability to climate hazards.

Table 1. Site Characteristics

Site Characteristics	Corona Fire Department HQ/Corp Yard
Address	735/755 Corporation-Yard Way, Corona, CA 92878
Census Tract IDs (2023)	(1) 06065040808 (2) 06065040809 (3) 06065040813 (4) 06065041500 (5) 06065041601 (6) 06065041602 (7) 06065041703 (8) 06065041704 (9) 06065046602
Climate Vulnerability	**High/Medium Risk Climate Hazards *(one or more tracts above CVI 50th national vulnerability percentile[1])*:** Drought; Wildfire; Flooding **Site Facility in 100-year Floodplain:** No
Pedestrian Accessibility	**Percent of the Service Area within a 15 min Walk to the Facility[2]:** 32% **Major Network/Sidewalk Gaps:** There appear to be sidewalks on most streets in the area, however access to the site from the north and west is restricted due to physical barriers such as private industrial facilities, canals, and a detention pond. Additionally railroad tracks run south of the site and restrict access from some areas where crossing is not feasible.
Public Transit Accessibility	**Total Routes Serving the Site Area:** 9 transit routes (3 rail, 6 bus) **Total Stops in the Site Area:** 37 transit stops (2 rail, 35 bus) **Distance to Nearest Stop:** 0.8 miles to the closest bus stops on River Rd and Main St to the east of the site. It is 0.9 miles to the Corona North Main train station and 1 mile to the Corona Transit Center. Pedestrian travel to access stops is possible but the most direct route crosses through warehouse parking lots and in some cases involves crossing busy streets or railroad tracks. There appears to be sidewalks on a majority of the route to the closest transit stops.
Proximity to Evacuation Routes or Major Highways	**Proximity to State Highway 91:** ~1 mile using Cota St and Railroad Street **Proximity to Interstate-15:** ~1.8 miles using W Rincon St and N Main St **Close Proximity to Evacuation Routes:** ~0.42 miles to Railroad St.; ~0.71 miles to River Rd

[1] The Climate Vulnerability Index (CVI) uses 2010 Census tracts. https://map.climatevulnerabilityindex.org/map/cvi_overall/usa?mapBoundaries=Tract&mapFilter=0&reportBoundaries=Tract&geoContext=State

[2] Walksheds were developed in Urban Footprint and use parcel areas, excluding rights-of-way, to calculate the percent of the service area that is within a 15-minute walk from the facility. Learn more about Urban Footprint software: https://urbanfootprint.com/

Community Profile

The median household incomes of tracts in the surrounding community are on average lower compared to the State's Median Household Income (MHI). Over half (5 of 9) of the census tracts that intersect with the site area are a designated SB 535 Disadvantaged Community determined by the top 25% of CalEnviroScreen 4.0 percentile scores.[3] Table 2 provides the surrounding population size and priority population factors for each tract compared to state averages, noting in red when census tracts are below the state average and noting in green when census tracts are above the state average.

[3] State of California OEHHA. SB 535 Disadvantaged Communities. https://oehha.ca.gov/calenviroscreen/sb535

Table 2. Community Characteristics

Characteristics	Corona Fire Department HQ/Corp Yard										
Surrounding Population Size[4]	13,685										
	Census Tracts										
Priority Population Factors	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**Average**	**State Average**
Disabled[5]	11.22%	11.10%	12.01%	11.07%	12.08%	4.17%	7.07%	12.66%	12.40%	10.42%	**11.65%**
Chronic Conditions[6]	26th percentile	41st percentile	61st percentile	13th percentile	10th percentile	10th percentile	8th percentile	6th percentile	64th percentile	**5 of 9 'Least Healthy' Tracts**	**'Least Healthy' below 25th percentile statewide**
Limited English[7]	10.22%	10.54%	6.00%	18.95%	27.96%	35.05%	26.14%	27.69%	6.77%	18.81%	**17.08%**
Children Under 5[8]	10.28%	4.65%	4.30%	3.91%	5.17%	4.08%	8.19%	6.54%	5.60%	5.86%	**5.44%**
Elderly Over 75[9]	5.26%	6.90%	7.22%	3.91%	3.67%	0.67%	2.41%	1.19%	7.09%	4.26%	**6.66%**
Pregnant People[10]	4.84%	3.95%	6.38%	1.00%	5.74%	1.78%	2.94%	4.13%	1.35%	3.57%	**4.86%**
Low Income[11]	$102,147	$80,938	$146,919	$78,571	$48,940	$63,565	$59,828	$59,219	$124,670	$84,977	**$104,103.66**
No Vehicle Access[12]	7.28%	2.84%	1.74%	5.50%	12.98%	5.93%	6.67%	5.28%	0.00%	5.36%	**7.15%**
Homelessness[13]	In January 2024 the Riverside City and County CoC had a total of 4,249 homeless persons, 57% of which were not sheltered by emergency shelter or transitional housing. Comparatively, 34% of the state of California's homeless population was not sheltered by emergency shelter or transitional housing.										

[4] The service population was calculated using 2020 Census blocks within the 1-mile service area. Some of the blocks included in this calculation go beyond the service area boundary. Blocks that intersect with the service area but do not have a significant portion of the block within the service area were excluded.
[5] ACS 5-year 2019-2023 Census: Disabled Populations
[6] Healthy Places Index (HPI)
[7] ACS 5-year 2019-2023 Census: Language Spoken at Home for the Population 5 Years and Over
[8] ACS 5-year 2019-2023 Census: Sex & Age
[9] ACS 5-year 2019-2023 Census: Sex & Age
[10] ACS 5-year 2019-2023 Census: Women 15 to 50 Years Who Had a Birth in the Past 12 Months
[11] ACS 5-year 2019-2023 Census: Median Household Income
[12] ACS 5-year 2019-2023 Census: Households with No Vehicle
[13] The U.S. Department of Housing and Urban Development reports on homelessness from point-in-time information by Continuums of Care (CoCs) that provides counts for sheltered and unsheltered homeless persons by household type and subpopulation. For more information see https://www.hudexchange.info/programs/coc/coc-homeless-populations-and-subpopulations-reports/.

Facility Profile

The Fire Department HQ/Corporation Yard is part of a City of Corona complex of city facilities in the area that also includes the Corona Police Department. The following tables provide an overview of the results of the facility evaluation for criteria that were developed under the USDN five foundational areas of resilience hubs: Communications, Building & Landscape, Power, Operations & Maintenance, and Services & Programming.[14] Green rows indicate criteria is met, and red rows indicate criteria is not met.

Communications

Broadband Access	Yes
Wired-Phone / Satellite Phone	*Does the facility have a wired or satellite phone available?* One satellite phone, and Starlink in the EOC is pending
Ability to Charge Communication Devices / Medical Devices	Yes

Building & Landscape

Heating and Cooling	*How old is the existing HVAC system? When is the planned/estimated replacement?* The HVAC system was installed in 2008 and is recommend to be replaced in 3 years.
	Does the unit have an air filtration system of at least MERV 13? Yes, MERV-8 filters are used for the system
Potable Water Sources	Yes
Water Resupply Methods/ Plans	Yes, the EOC stores both 10-year and 50-year shelf-life emergency water products and the Fire Department HQ stores on average 25 cases of water
Resilience to Climate Hazards	*Was the facility built to withstand climate hazards that may impact the site? [Flooding, Drought, Wildfire]* The structure is not located within a Fire Hazard Severity Zone. It is a concrete, non-combustible building with limited vegetation, none of which is against the structure, and all landscaping is regularly watered and maintained. The attached rear awning is also non-combustible and contains only non-combustible tables and chairs. There is significant emergency access on all sides of the building, and the facility is equipped with an automatic fire sprinkler system.
Rainwater Harvesting / Water Capture and Filtration	No, space outside of facility is limited
Space for Community Garden	No, space outside of the facility is limited and has little vegetation

[14] USDN. *Resilience Hubs: Five Foundational Areas*. Resilience Hub Five Foundational Areas

Power

Power Infrastructure	The site has an existing standby emergency generator and associated infrastructure in place. Provided information did not indicate any critical limitation(s) of existing facility circuitry prohibitive to microgrid development. Available roof and parking lot(i.e., carport) space for photovoltaic array(s) is adequate for onsite generation capacity sufficient to meet or exceed present-day demand. In short, the site is "microgrid-ready." Details available in accompanying *Microgrid Feasibility Study*.
Back-Up Power	Yes

Operations & Maintenance

Emergency Capacity	The facility is not used as an evacuation or emergency shelter, but it does host the EOC.
Emergency Plan	Yes
Security	*Does the facility have a functioning alarm system?* Yes
	Does the facility have secure doors? Yes
	Does the facility have motion-activated lights in areas such as hallways and bathrooms? Yes
ADA Assessment	
Gross Floor Area	44,550 sq ft.
No. of people assumed	400
Criteria	Evaluation Notes
Route	**Meets accessibility needs:** A continuous, unobstructed path with gentle or no slopes, providing access from public spaces to the building.
Parking	**Meets accessibility needs:** Site provides an adequate number of accessible parking spaces with properly sized access aisles.
Building entrance	**Meets accessibility needs:** Accessible main entrance or signage is provided to accessible entry.
Restroom clearances	**To be verified:** Restrooms should include sufficient turning space, and door swings should meet accessibility requirements.
Restroom fixture	**To be verified:** Fixtures should meet accessibility clearance and mounting height requirements.
Interior circulation	**To be verified:** Interior pathways should be unobstructed.

Multi-story accessibility	**To be verified:** All levels of the building should be accessible via an elevator or lift.

Services & Programming

Educational Programs	• The Corona Fire Department offers a free CPR Training Program to any interested residents, school, group or business consisting of video instructions, lecture, and hands-on practice • CERT volunteers are trained in emergency procedures and are duly registered as Disaster Service Workers in accordance with the California Government Code and the City of Corona Municipal Code. • The Public Access Defibrillation (PAD) program is to provide the training and resources to aid in the successful resuscitation of a victim of sudden cardiac arrest (SCA). • The City of Corona Fire Explorer Post 360 is comprised of young adults who are eager to gain real life experiences, training, and exposure to the career opportunities of the fire service.
Recreation & Wellness	• None identified
Programming for Seniors	• None identified
Emergency Response Training	• Fire Department HQ staff are safety employees and have received advanced training on emergency response and preparedness and refresh this training on a bi-annual basis. The Fire Department currently does not offer emergency response or preparedness training to our office staff. The City Emergency Manager may elect to provide them positions in upcoming CERT classes to build up our trained individuals at Fire Department HQ. • The City of Corona provides training and education to all staff through the Electronic Emergency Response Guide (ERG).
Partnerships	• Vial for Life – Corona Fire Safety Foundation, Corona Regional Medical Center, kaiser Permanente

Gaps and Recommendations

Site Access

The site is located in an industrial area that borders commercial and residential areas. On most streets in the service area, sidewalks appear to be present on at least one side of the road, however a more thorough assessment of sidewalk condition and network gaps could be conducted to better understand how accessible the site is for pedestrians. For both pedestrians and vehicles, access to the site is restricted due to physical barriers to the north, west, and south including private industrial properties, canals, a detention pond, and railroad tracks without crossings. The facility can consider if residents in these areas with less direct access may come to the facility during an emergency, if there is another community resilience center in these areas, or if a secondary or alternate location for the community resilience center needs to be established that has better access from surrounding neighborhoods.

The site is a mile or less from both a train station with Amtrak service and transit center with bus service from the City of Corona and Riverside Transit Agency, providing regional transportation to and from the site in the event of an evacuation. Since a mile may be an inaccessible distance to walk for some members of the community, the facility can consider having a shuttle or carpool service from the train and adjacent transit center to the facility during an emergency. Additionally, the area has many industrial facilities, major roadways, and railroad tracks that make access between the facility and transit services less safe and comfortable for pedestrians. The facility can work with the City of Corona to consider how pedestrian infrastructure such as crosswalks and traffic calming measures such as curb extensions could be improved in the service area to increase walkability.

Priority Population Considerations

Over half of the census tracts within the service area are considered “least healthy” by the Healthy Places Index. To better understand the specific chronic conditions, physical health, and mental well-being of the service population, the facility could conduct outreach through surveys and community events that build trust with the community. Once an understanding of the community’s health conditions is developed, the facility could incorporate into emergency plans and operations the specific needs of those with chronic health conditions. For example, community members who rely on medications that require refrigeration or medical equipment that require electricity. The facility may continue to provide programing that promotes healthy lifestyles and reduces the risk of chronic health conditions in the community.

The percentage of limited English speakers in the service area is greater compared to the state average. This population may need greater support accessing disaster information and recovery resources. The facility can understand the languages spoken in the community through census data or by conducting outreach with residents. Then informational materials on disaster, educational preparedness, and recovery resources can be created in these languages. For prominent languages spoken in the community it is helpful to have staff at the facility who are able to translate and further support these community members.

The average percentage of children under five in the service area is greater than the state average, meaning there may be more families with young children and infants using the facility during an emergency. To address the needs of children and their families during and after an emergency, the facility could provide childcare services and mental health services focused on trauma support for children during and after an emergency.

The average median household income in the service area tracts is lower than the state’s. To address the needs of lower-income communities during and after an emergency, the facility can

provide services for logistical support for communication with recovery agencies and insurance companies. Additionally, lower-income populations can feel especially stressed about financial planning and providing basic resources for themselves and their family after a disaster. The facility could consider offering or coordinating mental health services for these populations.

Although data on homeless persons is provided at the regional level, homelessness is best understood locally. The facility may consider if there is a visible presence of homeless persons in the service area of the facility, if the population seems to be growing, and if the facility has previously been a resource for homeless persons. This population may need additional support and services when sheltered during an emergency. Strategies to support this population that the facility can consider include coordination with local homeless shelters for disaster preparedness, understanding the capacity of homeless persons in the area the facility may need to support, and providing mental health and medical services.[15]

Building Resilience Checklist

The site area is vulnerable to drought, wildfires, and flooding. The following are suggestions for the facility to build resilience against these hazards.

Drought:

☐ Water conservation measures such as efficient plumbing fixtures and low-flow toilets

☐ Native landscaping and xeriscaping

☐ Recycled water system

Wildfire:

☐ Proper HVAC air filtration for internal air quality (wildfire smoke)

☐ Fire resistant construction that uses non-combustible or fire-resistant building materials for renovations or reconstruction

☐ Fire-resistant plants used in landscaping

Flooding:

☐ Wet floodproofing solutions – engineered flood vents and water-resistant building materials

☐ Dry floodproofing solutions – flood gates, backflow preventers on drains, sealing openings in walls and foundations, sump pumps, and waterproof enclosures

☐ Site perimeter floodproofing – sand bags, water-inflated tube systems and flood panels

☐ Elevated mechanical and electrical equipment to the roof or other areas above the flood level

☐ Stormwater management solutions – permeable pavers, bioswales, and green roofs

Facility Accessibility & Infrastructure

ADA Compliance

An ADA assessment could not be fully completed for the Corona Fire Department HQ/ Corporation Yard. A full assessment can be made after review of the Building 1 building plans. This ADA assessment is based on the building's intended use as defined by its code designation. Additional investigations and requirements may be necessary to accommodate

[15] U.S. Housing and Development. *Disaster Recovery – Homelessness Toolkit.* https://files.hudexchange.info/resources/documents/DR-H-Preparedness-Checklist-Shelter-and-Services.pdf

emergency lodging, bathing, and waste disposal, as determined by the authority having jurisdiction.

Facility Infrastructure

To support the facility to act as a community resilience center during and after an emergency, the facility can:

- Assess the feasibility of adding a rain garden or capture and filtration system to the facility or a nearby facility.
- Consider the feasibility of partnering with a nearby HOA or POA to create a community garden that can build community and provide fresh food.

Facility Operations & Disaster Preparedness

The community resilience center staff and volunteers can take steps to integrate processes and training that support the continued operation of the community resilience center in all operating conditions: normal operations, during an event, and after an event. Along with having a facility emergency plan, additional disaster preparedness strategies include the following:

- Determine appropriate and functional communication channels with the community to notify them the community resilience center is open, alert them of emergency updates, coordinate resources, and share general information.
- Identify key personnel and what role they will have in each of the operating modes.
- Identify and provide training for key personnel to increase preparedness and knowledge.
- Identify and provide training for community members to increase community adaptive capacity.
- Identify funding and partnerships to support key personnel in operating the community resilience center.

Additional Resources

Community resilience and disaster preparedness are broad topics with many detailed best practices and approaches. In addition to some key strategies summarized above, the following resources provide tools and guidance to prepare for disaster and build community resilience:

- Bay Localize, 2020. *Community Resilience Toolkit* (Link)
- Central Coast Climate Collaborative, 2025. What is a Community Resilience Hub? (Link)
- District of Columbia Department of Energy and Environment, 2025. Community Resilience Hubs (Link)
- U.S. Department of Homeland Security, 2025. *People with Disabilities* (Link)
- Urban Sustainability Directors Network, 2017. *Guide to Equitable, Community-Driven Climate Preparedness Planning* (Link)
- Urban Sustainability Directors Network, 2019. *Guide to Developing Resilience Hubs* (Link)

AECOM

Community Resilience Center Feasibility Study

City of Lake Elsinore

Lake Community Center

February 2026

Delivering a better world

Introduction

In recent years, communities across the Inland Empire have experienced increasingly severe climate hazard conditions, including, but not limited to, wildfires, extreme heat, extreme winds, and flash flooding. Consequently, community resources and utility services continue to face frequent and impactful disruptions across Riverside County.

In 2023, the Western Riverside Council of Governments (WRCOG) was awarded a grant under the Integrated Climate Adaptation and Resiliency Program from the Governor's Office of Land Use and Climate Innovation to develop an *Energy Resilience Plan 2.0*. The grant project includes feasibility studies for Community Resilience Centers for WRCOG member agencies.

Community Resilience Center – Permanent community-serving facility equipped to support residents and coordinate essential resource distribution and services before, during, and after an emergency event

Distinct from an emergency shelter, a Community Resilience Center serves as a year-round resource hub that can be activated for response functions during emergency events. It is defined by the infrastructure and building components (e.g., backup power, air filtration, alternate communications), service functions (e.g., community gathering, social programming), and accessibility that support community resilience in both business-as-usual and emergency scenarios, typified in these prototypical modes of operation:

- Steady State – Acts in ordinary community-serving capacity (e.g., community center, senior center, fire station)
- Disruption (During Emergency Event) – Provides immediate relief, shelter, and access to resources for residents and community members
- Recovery (Post-Emergency) – Can serve as a central location for resource distribution, mutual aid and volunteer coordination, etc.

The Lake Community Center was selected by the City of Lake Elsinore to be evaluated for its viability to serve as a Community Resilience Center. Feasibility assessment results are presented as follows:

- Site Profile
- Community Profile
- Facility Profile
- Gaps and Recommendations

This document is intended to serve the City of Lake Elsinore with first step analysis in identifying an opportunity to improve community resilience. The *Energy Resilience Plan 2.0* provides further guidance on resilience strategies and implementation considerations.

From the Governor's Office of Land Use and Climate Innovation

As communities in California experience more frequent, prolonged, and severe impacts from climate change, communities and governments at all scales are developing strategies and implementing actions to build a climate- resilient future. However, many jurisdictions, especially under-resourced communities in California, lack the capacity, tools, guidance, and resources to effectively prepare for climate impacts.

The Adaptation Planning Grant Program addresses this capacity gap by providing funding to help fill planning needs, providing communities with the resources to identify climate resilience priorities, and supporting the development of climate resilience projects across the state. The Adaptation Planning Grant Program enables communities to climate risk and adaptation considerations into planning activities and prepare for climate readiness and resilience in the long term.

The Adaptation Planning Grant is part of the Integrated Climate Adaptation and Resiliency Program (ICARP) housed within the Governor's Office of Land Use and Climate Innovation (LCI). ICARP advances statewide climate adaptation and resilience by coordinating investments, partnerships, and climate science to ensure people, natural systems, and the built environment are protected, prepared, and thrive in the face of climate change.

Through direct and equity-focused investments and resources, ICARP helps build climate adapted and equitable communities in California, with a focus on solutions that address the impacts of climate change and reduce greenhouse gas emissions. ICARP works to advance these priorities across all levels of government by developing actionable science and research; providing guidance, tools, and technical assistance; and administering climate resilience-focused grant programs.

Learn more: https://lci.ca.gov/climate/icarp/

Site Profile

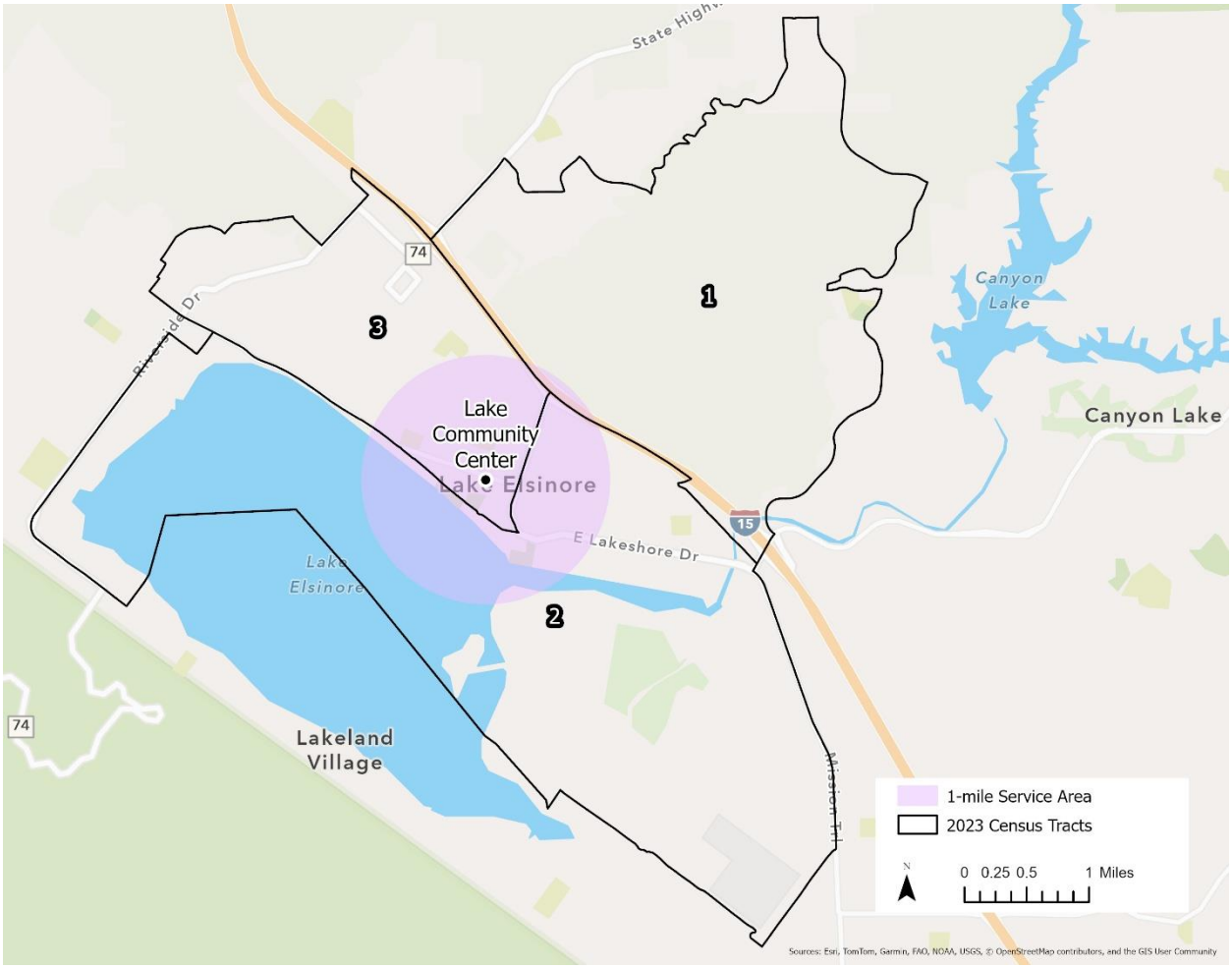


Figure 1. Site Location Map

The Lake Community Center is located north of the lake, a few blocks away from the city's main street, and south of Interstate 15. For the purpose of the assessment, the service area was determined to be the area within a 1-mile radius of the site (shown in Figure 1). There are three census tracts that intersect with the service area and these were used to assess the site's climate vulnerability and the community's priority populations (See Table 1 for census tract IDs). However, the census tract boundaries go beyond the service area boundaries. Therefore, characteristics are provided for an area greater than the 1-mile radius from the site.

Table 1 provides the site's accessibility and vulnerability to climate hazards.

Table 1. Site Characteristics

Site Characteristics	Lake Community Center
Address	310 W Graham Ave, Lake Elsinore, CA 92530
Census Tract IDs (2023)	(1) 06065042750 (2) 06065043001 (3) 06065043006
Climate Vulnerability	**High/Medium Risk Climate Hazards *(one or more tracts above CVI 50th national vulnerability percentile[1])*:** Drought; Wildfire; Flooding **Site Facility in 100-year Floodplain:** No
Pedestrian Accessibility	**Percent of the Service Area within a 15 min Walk to the Facility[2]:** 35% **Major Network/Sidewalk Gaps:** There do not appear to be any major pedestrian network gaps to access or evacuate the site area.
Public Transit Accessibility	**Total Routes Serving the Site Area:** 1 transit route **Total Stops in the Site Area:** 16 transit stops **Distance to Nearest Stop:** 0.02 mi outside of the site on Graham Ave. The sidewalk surrounding the site appears to be in good condition and continuous.
Proximity to Evacuation Routes or Major Highways	**Close Proximity to Interstate 15:** ~0.9 mile using Main Street **Located on an Evacuation Route** (Graham Ave)

[1] The Climate Vulnerability Index (CVI) uses 2010 Census tracts. https://map.climatevulnerabilityindex.org/map/cvi_overall/usa?mapBoundaries=Tract&mapFilter=0&reportBoundaries=Tract&geoContext=State

[2] Walksheds were developed in Urban Footprint and use parcel areas, excluding rights-of-way, to calculate the percent of the service area that is within a 15-minute walk from the facility. Learn more about Urban Footprint software: https://urbanfootprint.com/

Community Profile

The median household incomes of tracts in the surrounding community are on average lower compared to the State's Median Household Income (MHI). One of the three census tracts that intersect with the site area is a designated SB 535 Disadvantaged Community determined by the top 25% of CalEnviroScreen 4.0 percentile scores.[3] Table 2 provides the surrounding population size and priority population factors for each tract compared to state averages, noting in red when census tracts are below the state average and noting in green when census tracts are above the state average.

Table 2. Community Characteristics

Characteristics	Lake Community Center				
Surrounding Population Size[4]	7,795				
	Census Tracts				
Priority Population Factors	**1**	**2**	**3**	**Average**	**State Average**
Disabled[5]	12.18%	8.40%	15.31%	**13.86%**	**11.65%**
Chronic Conditions[6]	45th percentile	23rd percentile	9th percentile	**2 of 3 'Least Healthy' Tracts**	**'Least Healthy' below 25th percentile statewide**
Limited English[7]	6.23%	11.81%	18.99%	**12.34%**	**17.08%**
Children Under 5[8]	5.15%	10.95%	3.36%	**6.49%**	**5.44%**
Elderly Over 75[9]	3.09%	1.78%	7.89%	**4.25%**	**6.66%**
Pregnant People[10]	3.15%	10.40%	6.76%	**6.77%**	**4.86%**
Low Income[11]	$93,750	$93,768	$55,333	$80,950	**$104,103**
No Vehicle Access[12]	0.76%	4.18%	8.18%	4.37%	**7.15%**
Homelessness[13]	In January 2024 the Riverside City and County CoC had a total of 4,249 homeless persons, 57% of which were not sheltered by emergency shelter or transitional housing. Comparatively, 34% of the state of California's homeless population was not sheltered by emergency shelter or transitional housing.				

[3] State of California OEHHA. SB 535 Disadvantaged Communities. https://oehha.ca.gov/calenviroscreen/sb535
[4] The surrounding population size was calculated using 2020 Census blocks within the 1-mile service area. Some of the blocks included in this calculation go beyond the service area boundary. Blocks that intersect with the service area but do not have a significant portion of the block within the service area were excluded.
[5] ACS 5-year 2019-2023 Census: Disabled Populations
[6] Healthy Places Index (HPI)
[7] ACS 5-year 2019-2023 Census: Language Spoken at Home for the Population 5 Years and Over
[8] ACS 5-year 2019-2023 Census: Sex & Age
[9] ACS 5-year 2019-2023 Census: Sex & Age
[10] ACS 5-year 2019-2023 Census: Women 15 to 50 Years Who Had a Birth in the Past 12 Months
[11] ACS 5-year 2019-2023 Census: Median Household Income
[12] ACS 5-year 2019-2023 Census: Households with No Vehicle
[13] The U.S. Department of Housing and Urban Development reports on homelessness from point-in-time information by Continuums of Care (CoCs) that provides counts for sheltered and unsheltered homeless persons by household type and subpopulation. For more information see https://www.hudexchange.info/programs/coc/coc-homeless-populations-and-subpopulations-reports/.

Facility Profile

The Lake Community Center was originally built in the 1950s as a movie theater but was renovated in 1990 to become the City's first Senior and Community Center.[14] The center offers a spacious gymnasium with an attached kitchen and operates programs for all ages.[15] The following tables provide an overview of the results of the facility evaluation for criteria that were developed under the USDN five foundational areas of resilience hubs: Communications, Building & Landscape, Power, Operations & Maintenance, and Services & Programming.[16] Green rows indicate criteria is met, and red rows indicate criteria is not met.

Communications

Broadband Access	Yes, the City of Lake Elsinore is in the process of switching to StarLink systems
Wired-Phone / Satellite Phone	Yes - The Lake Community Center has a portable satellite phone and the City of Lake Elsinore has 10 satellite phones used by some center staff members. The satellite antenna is hosted at the Emergency Operations Center. The City of Lake Elsinore also has its own UHS radio, and 3 dedicated radios as a part of the Riverside County Public Safety Enterprise Communication Project (PSEC).
Ability to Charge Communication Devices / Medical Devices	Yes

Building & Landscape

Heating and Cooling	*How old is the existing HVAC system? When is the planned/estimated replacement?* The unit is 7 years old and is planned to be replaced 5-8 years from now
	Does the unit have an air filtration system of at least MERV 13? Yes
Potable Water Sources	Yes
Water Resupply Methods/ Plans	Yes
Resilience to Climate Hazards	*Was the facility built to withstand climate hazards that may impact the site? [Flooding, Drought, Wildfire]* Unknown at this time
Rainwater Harvesting / Water Capture and Filtration	No
Space for Community Garden	Yes

[14] City of Lake Elsinore. Facilities – Lake Community Center. https://www.lake-elsinore.org/Facilities/Facility/Details/Lake-Community-Center-27
[15] City of Lake Elsinore. Facilities – Lake Community Center. https://www.lake-elsinore.org/Facilities/Facility/Details/Lake-Community-Center-27
[16] USDN. *Resilience Hubs: Five Foundational Areas*. Resilience Hub Five Foundational Areas

Power

Power Infrastructure	Provided information did not indicate any critical limitation(s) of existing facility circuitry prohibitive to microgrid development. Available roof and parking lot (i.e., carport) space for photovoltaic array(s) is adequate for onsite generation capacity sufficient to meet or exceed present-day demand. In short, the site is "microgrid-ready." Details available in accompanying *Microgrid Feasibility Study*.
Back-Up Power	No

Operations & Maintenance

Emergency Capacity	The center is currently used as a shelter during emergency evacuations.
Emergency Plan	Yes, for specific aspects of the center (Care and Reception)
Security	*Does the facility have a functioning alarm system?* Yes
	Does the facility have secure doors? Yes
	Does the facility have motion-activated lights in areas such as hallways and bathrooms? No
ADA Assessment	
Gross Floor Area	10,920 sq ft
No. of people assumed	115 during the day; 150 when acting as an emergency shelter
Criteria	Evaluation Notes
Route	**To be verified:** Site should offer a continuous, unobstructed path with gentle or no slopes, providing access from public spaces to the building.
Parking	**To be verified:** Site should provide an adequate number of accessible parking spaces with properly sized access aisles.
Building entrance	**To be verified:** Site should offer an accessible main entrance or provide signage to accessible entry.
Restroom clearances	**To be verified:** Restrooms should include sufficient turning space, and door swings should meet accessibility requirements.
Restroom fixture	**To be verified:** Fixtures should meet accessibility clearance and mounting height requirements.
Interior circulation	**To be verified:** Interior pathways should be unobstructed.

Multi-story accessibility	**To be verified:** All levels of the building should be accessible via an elevator or lift.

Services & Programming

Educational Programs	• Educational program for kids
Recreation & Wellness	• Social activities for adults • Winter Day Camp • Summer Day Camp • Fall Basketball
Programming for Seniors	• None identified
Emergency Response Training	• Staff receive training through the City of Lake Elsinore Emergency Services Division
Partnerships	• Lowes • Red Cross • Costco

Gaps and Recommendations

Site Access

The site is served by public transit, sidewalks, and roadways making the site accessible for populations using a variety of modes within the City of Lake Elsinore. Riverside Transit Agency's bus route 8 has a stop located on Graham Ave directly outside of the Lake Community Center that provides access to and from areas throughout the City of Lake Elsinore. Sidewalks in the area appear to be in good condition and provide pedestrian access from multiple directions, in addition to connecting to transit stops in the area. Graham Ave serves as an evacuation route that connects to Interstate-15. The site is bordered by Lake Elsinore to the southwest so access in this direction has increased travel time in order to circumvent the lake.

Priority Population Considerations

While the census data shows that the service area's average percent of the population that is disabled is greater the state average, the types of disabilities are not known. This assessment focused on the accessibility (ADA compliance) of the facility itself. The facility can coordinate with the local transit or rideshare provider for accessible transportation to and from the facility and provide back-up power for those who use medical equipment that requires electricity. The facility may need work with the City of Lake Elsinore to review sidewalk accessibility, as well as conduct outreach with residents to evaluate additional accessibility needs.

Two-thirds of the census tracts within the service area are considered "least healthy" by the Healthy Places Index. To better understand the specific chronic conditions, physical health, and mental well-being of the service population, the facility could conduct outreach through surveys and community events that build trust with the community. Once an understanding of the community's health conditions is developed, the facility could incorporate into emergency plans and operations the specific needs of those with chronic health conditions. For example, community members who rely on medications that require refrigeration or medical equipment that require electricity. The community center may continue to provide programing that promotes healthy lifestyles and reduces the risk of chronic health conditions in the community.

The average percentage of children under five in the service area is greater than the state average, meaning there may be more families with young children and infants using the facility during an emergency. To address the needs of children and their families during and after an emergency, the facility could provide childcare services and mental health services focused on trauma support for children during and after an emergency.

The average percentage of women 15 to 50 years who had a birth in the past 12 months in the service area is greater than the state average, meaning there may be more pregnant people using the facility during an emergency. To address the needs of this population, the facility could integrate maternal and child health considerations into emergency plans, provide basic medical services at the facility during and after an emergency, and coordinate with public health agencies and healthcare providers to provide supplies for infant feeding and educational resources for new parents.[17] It is also important to consider if the facility has adequate access to evacuation routes that can connect to a hospital in the case of a pregnancy occurring during or after an emergency. The Lake Community Center is located on an evacuation route that can provide access to the interstate and local medical facilities.

The average median household income in the service area tracts is lower than the state's. To address the needs of lower-income communities during and after an emergency, the facility can

[17] U.S. Center for Disease Control. *Reproductive Health – Emergency Preparedness and Response Tools and Resources.* https://www.cdc.gov/reproductive-health/php/emergency-tools/index.html

provide services for logistical support for communication with recovery agencies and insurance companies. Additionally, lower-income populations can feel especially stressed about financial planning and providing basic resources for themselves and their family after a disaster. The facility could consider offering or coordinating mental health services for these populations.

Although data on homeless persons is provided at the regional level, homelessness is best understood locally. The facility may consider if there is a visible presence of homeless persons in the service area of the facility, if the population seems to be growing, and if the facility has previously been a resource for homeless persons. This population may need additional support and services when sheltered during an emergency. Strategies to support this population that the facility can consider include coordination with local homeless shelters for disaster preparedness, understanding the capacity of homeless persons in the area the facility may need to support, and providing mental health and medical services.[18]

Building Resilience Checklist

The site area is vulnerable to drought, wildfires, and flooding. The following are suggestions for the facility to build resilience against these hazards.

Drought:

☐ Water conservation measures such as efficient plumbing fixtures and low-flow toilets

☐ Native landscaping and xeriscaping

☐ Recycled water system

Wildfire:

☐ Proper HVAC air filtration for internal air quality (wildfire smoke)

☐ Fire resistant construction that uses non-combustible or fire-resistant building materials for renovations or reconstruction

☐ Fire-resistant plants used in landscaping

Flooding:

☐ Wet floodproofing solutions – engineered flood vents and water-resistant building materials

☐ Dry floodproofing solutions – flood gates, backflow preventers on drains, sealing openings in walls and foundations, sump pumps, and waterproof enclosures

☐ Site perimeter floodproofing – sand bags, water-inflated tube systems and flood panels

☐ Elevated mechanical and electrical equipment to the roof or other areas above the flood level

☐ Stormwater management solutions – permeable pavers, bioswales, and green roofs

Facility Accessibility & Infrastructure

ADA Compliance

An ADA assessment could not be completed for the Lake Community Center. A full assessment can be made after review of the building and site plans. An ADA assessment is based on the building's intended use as defined by its code designation. Additional investigations and requirements may be necessary to accommodate emergency lodging, bathing, and waste disposal, as determined by the authority having jurisdiction.

[18] U.S. Housing and Development. *Disaster Recovery – Homelessness Toolkit.* https://files.hudexchange.info/resources/documents/DR-H-Preparedness-Checklist-Shelter-and-Services.pdf

Facility Infrastructure

To support the facility to act as a community resilience center during and after an emergency, the facility can:

- Install a back-up power generator to prepare for power outages that often result from natural disasters and extreme weather events.
- Assess the feasibility of adding a rain garden or capture and filtration system to the facility.
- Install motion-activated lights in areas such as hallways and bathrooms for added security inside the facility.

Facility Operations & Disaster Preparedness

The community resilience center staff and volunteers can take steps to integrate processes and training that support the continued operation of the community resilience center in all operating conditions: normal operations, during an event, and after an event. Along with having a facility emergency plan, additional disaster preparedness strategies include the following:

- Determine appropriate and functional communication channels with the community to notify them the community resilience center is open, alert them of emergency updates, coordinate resources, and share general information.
- Identify key personnel and what role they will have in each of the operating modes.
- Identify and provide training for key personnel to increase preparedness and knowledge.
- Identify and provide training for community members to increase community adaptive capacity.
- Identify funding and partnerships to support key personnel in operating the community resilience center.

Additional Resources

Community resilience and disaster preparedness are broad topics with many detailed best practices and approaches. In addition to some key strategies summarized above, the following resources provide tools and guidance to prepare for disaster and build community resilience:

- Bay Localize, 2020. *Community Resilience Toolkit* (Link)
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- District of Columbia Department of Energy and Environment, 2025. Community Resilience Hubs (Link)
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AECOM

Community Resilience Center Feasibility Study

City of Moreno Valley

Moreno Valley Senior Center

February 2026

Delivering a better world

Introduction

In recent years, communities across the Inland Empire have experienced increasingly severe climate hazard conditions, including, but not limited to, wildfires, extreme heat, extreme winds, and flash flooding. Consequently, community resources and utility services continue to face frequent and impactful disruptions across Riverside County.

In 2023, the Western Riverside Council of Governments (WRCOG) was awarded a grant under the Integrated Climate Adaptation and Resiliency Program from the Governor's Office of Land Use and Climate Innovation to develop an *Energy Resilience Plan 2.0*. The grant project includes feasibility studies for Community Resilience Centers for WRCOG member agencies.

Community Resilience Center – Permanent community-serving facility equipped to support residents and coordinate essential resource distribution and services before, during, and after an emergency event

Distinct from an emergency shelter, a Community Resilience Center serves as a year-round resource hub that can be activated for response functions during emergency events. It is defined by the infrastructure and building components (e.g., backup power, air filtration, alternate communications), service functions (e.g., community gathering, social programming), and accessibility that support community resilience in both business-as-usual and emergency scenarios, typified in these prototypical modes of operation:

- Steady State – Acts in ordinary community-serving capacity (e.g., community center, senior center, fire station)
- Disruption (During Emergency Event) – Provides immediate relief, shelter, and access to resources for residents and community members
- Recovery (Post-Emergency) – Can serve as a central location for resource distribution, mutual aid and volunteer coordination, etc.

The Moreno Valley Senior Center was selected by the City of Moreno Valley to be evaluated for its viability to serve as a Community Resilience Center. Feasibility assessment results are presented as follows:

- Site Profile
- Community Profile
- Facility Profile
- Gaps and Recommendations

This document is intended to serve the City of Moreno Valley with first step analysis in identifying an opportunity to improve community resilience. The *Energy Resilience Plan 2.0* provides further guidance on resilience strategies and implementation considerations.

From the Governor's Office of Land Use and Climate Innovation

As communities in California experience more frequent, prolonged, and severe impacts from climate change, communities and governments at all scales are developing strategies and implementing actions to build a climate- resilient future. However, many jurisdictions, especially under-resourced communities in California, lack the capacity, tools, guidance, and resources to effectively prepare for climate impacts.

The Adaptation Planning Grant Program addresses this capacity gap by providing funding to help fill planning needs, providing communities with the resources to identify climate resilience priorities, and supporting the development of climate resilience projects across the state. The Adaptation Planning Grant Program enables communities to climate risk and adaptation considerations into planning activities and prepare for climate readiness and resilience in the long term.

The Adaptation Planning Grant is part of the Integrated Climate Adaptation and Resiliency Program (ICARP) housed within the Governor's Office of Land Use and Climate Innovation (LCI). ICARP advances statewide climate adaptation and resilience by coordinating investments, partnerships, and climate science to ensure people, natural systems, and the built environment are protected, prepared, and thrive in the face of climate change.

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Learn more: https://lci.ca.gov/climate/icarp/

Site Profile

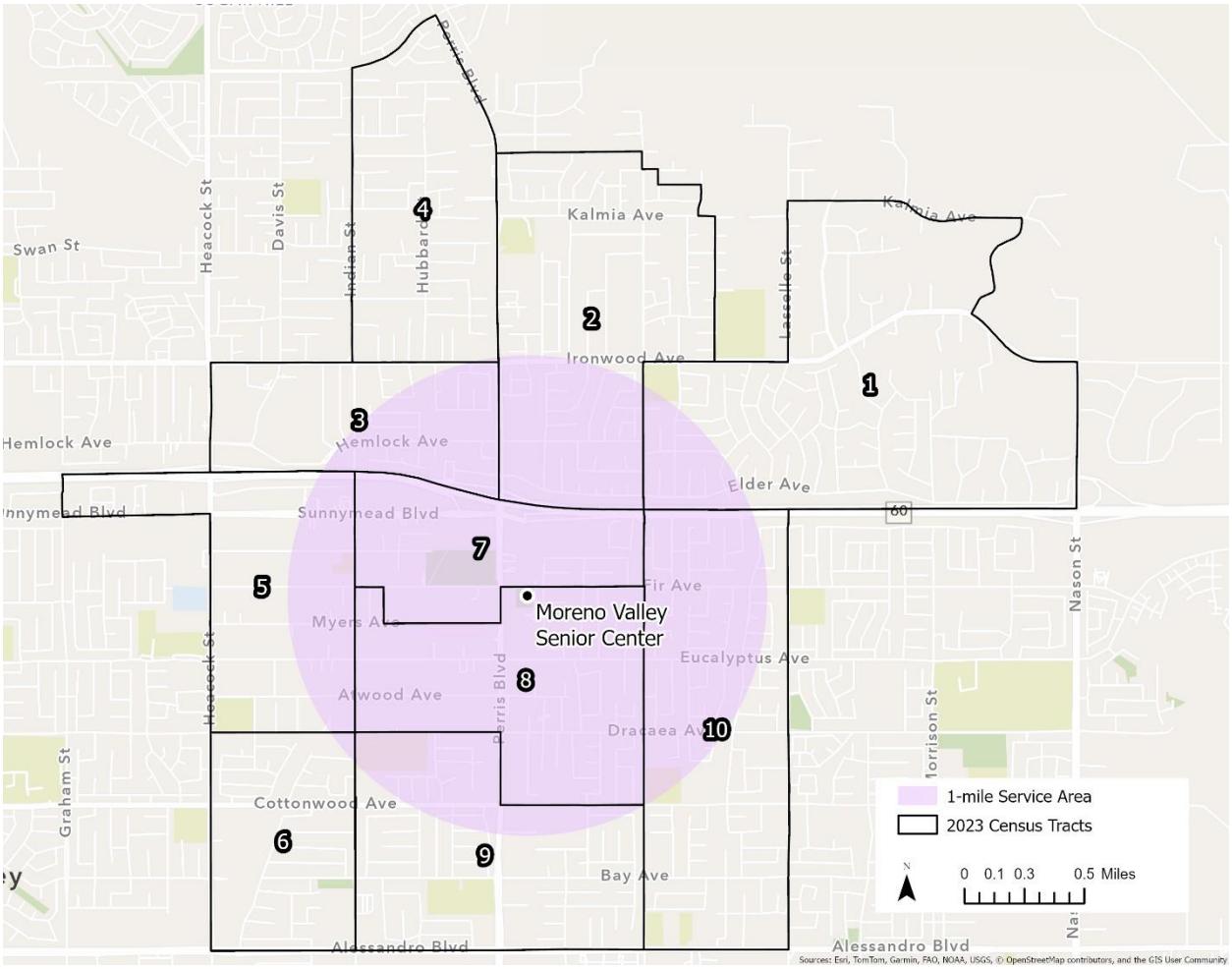


Figure 1. Site Location Map

The Moreno Valley Senior Center is located centrally in the City of Moreno Valley near Sunnymead Park and the Rio Rancho Super Mall. For the purpose of the assessment, the service area was determined to be the area within a 1-mile radius of the site (shown in Figure 1). There are 10 census tracts that intersect with the service area and these were used to assess the site's climate vulnerability and the community's priority populations (See Table 1 for census tract IDs). However, the census tract boundaries go beyond the service area boundaries. Therefore, characteristics are provided for an area greater than the 1-mile radius from the site.

Table 1 provides the site's accessibility and vulnerability to climate hazards.

Table 1. Site Characteristics

Site Characteristics	Moreno Valley Senior Center
Address	25075 Fir Ave, Moreno Valley, CA 92553
Census Tract IDs (2023)	(1) 06065042402 (2) 06065042403 (3) 06065042404 (4) 06065042408 (5) 06065042515 (6) 06065042516 (7) 06065042519 (8) 06065042520 (9) 06065042521 (10) 06065046800
Climate Vulnerability	**High/Medium Risk Climate Hazards *(one or more tracts above CVI 50th national vulnerability percentile[1])*:** Drought; Wildfire; Flooding **Site Facility in 100-year Floodplain:** No
Pedestrian Accessibility	**Percent of the Service Area within a 15 min Walk to the Facility[2]:** 37% **Major Network/Sidewalk Gaps:** There do not appear to be any major pedestrian network gaps to access or evacuate the site area.
Public Transit Accessibility	**Total Routes Serving the Site Area:** 2 transit routes **Total Stops in the Site Area:** 20 transit stops **Distance to Nearest Stop:** 0.01 miles outside of the site on Fir Ave. Pedestrian travel is possible on sidewalks from the senior center to the nearest transit stops.
Proximity to Evacuation Routes or Major Highways	**Close Proximity to State Highway 60:** ~0.5 mile using Fir Ave and Perris Blvd **Close Proximity to Evacuation Routes:** ~0.08 mile to Perris Blvd

[1] The Climate Vulnerability Index (CVI) uses 2010 Census tracts. https://map.climatevulnerabilityindex.org/map/cvi_overall/usa?mapBoundaries=Tract&mapFilter=0&reportBoundaries=Tract&geoContext=State

[2] Walksheds were developed in Urban Footprint and use parcel areas, excluding rights-of-way, to calculate the percent of the service area that is within a 15-minute walk from the facility. Learn more about Urban Footprint software: https://urbanfootprint.com/

Community Profile

The median household incomes of tracts in the surrounding community are on average lower compared to the State's Median Household Income (MHI). Over half (6 of 10) of the census tracts that intersect with the site area are a designated SB 535 Disadvantaged Community determined by the top 25% of CalEnviroScreen 4.0 percentile scores.[3] Table 2 provides the surrounding population size and priority population factors for each tract compared to state averages, noting in red when census tracts are below the state average and noting in green when census tracts are above the state average.

[3] State of California OEHHA. SB 535 Disadvantaged Communities. https://oehha.ca.gov/calenviroscreen/sb535

Table 2. Community Characteristics

Characteristics	Moreno Valley Senior Center											
Surrounding Population Size[4]	18,559											
Priority Population Factors	**Census Tracts**											
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**Average**	**State Average**
Disabled[5]	7.96%	11.65%	11.02%	11.27%	12.52%	11.35%	15.06%	6.22%	10.19%	10.87%	**10.81%**	**11.65%**
Chronic Conditions[6]	46th percentile	51st percentile	18th percentile	43rd percentile	2nd percentile	7th percentile	10th percentile	7th percentile	19th percentile	24th percentile	**7 of 10 'Least Healthy' Tracts**	**'Least Healthy' below 25th percentile statewide**
Limited English[7]	16.38%	10.03%	22.72%	17.49%	16.83%	26.03%	15.44%	36.96%	22.08%	20.54%	**20.45%**	**17.08%**
Children Under 5[8]	6.81%	4.61%	7.53%	5.78%	10.63%	4.09%	6.40%	5.68%	7.40%	5.19%	**6.41%**	**5.44%**
Elderly Over 75[9]	2.22%	1.07%	3.07%	2.99%	2.82%	1.60%	2.32%	2.18%	4.29%	2.22%	**2.48%**	**6.66%**
Pregnant People[10]	4.75%	7.74%	2.27%	3.07%	8.46%	2.67%	4.25%	17.22%	5.47%	5.77%	**6.17%**	**4.86%**
Low Income[11]	$101,250	$141,374	$87,981	$109,479	$52,957	$79,063	$47,857	$61,314	$84,044	$95,179	**$86,049**	**$104,103.66**
No Vehicle Access[12]	2.79%	0.00%	0.78%	0.00%	14.15%	1.97%	3.98%	9.49%	2.24%	0.96%	**3.64%**	**7.15%**
Homelessness[13]	In January 2024 the Riverside City and County CoC had a total of 4,249 homeless persons, 57% of which were not sheltered by emergency shelter or transitional housing. Comparatively, 34% of the state of California's homeless population was not sheltered by emergency shelter or transitional housing.											

[4] The service population was calculated using 2020 Census blocks within the 1-mile service area. Some of the blocks included in this calculation go beyond the service area boundary. Blocks that intersect with the service area but do not have a significant portion of the block within the service area were excluded.
[5] ACS 5-year 2019-2023 Census: Disabled Populations
[6] Healthy Places Index (HPI)
[7] ACS 5-year 2019-2023 Census: Language Spoken at Home for the Population 5 Years and Over
[8] ACS 5-year 2019-2023 Census: Sex & Age
[9] ACS 5-year 2019-2023 Census: Sex & Age
[10] ACS 5-year 2019-2023 Census: Women 15 to 50 Years Who Had a Birth in the Past 12 Months
[11] ACS 5-year 2019-2023 Census: Median Household Income
[12] ACS 5-year 2019-2023 Census: Households with No Vehicle
[13] The U.S. Department of Housing and Urban Development reports on homelessness from point-in-time information by Continuums of Care (CoCs) that provides counts for sheltered and unsheltered homeless persons by household type and subpopulation. For more information see https://www.hudexchange.info/programs/coc/coc-homeless-populations-and-subpopulations-reports/.

Facility Profile

The Moreno Valley Senior Center offers fitness classes, social gatherings, and creative workshops for seniors to promote health, well-being, and lifelong learning. The senior center also provides resources such as transportation and lunch service.[14] The following tables provide an overview of the results of the facility evaluation for criteria that were developed under the USDN five foundational areas of resilience hubs: Communications, Building & Landscape, Power, Operations & Maintenance, and Services & Programming.[15] Green rows indicate criteria is met, and red rows indicate criteria is not met.

Communications

Broadband Access	Yes
Wired-Phone / Satellite Phone	*Does the facility have a wired or satellite phone available?* Unknown at this time
Ability to Charge Communication Devices / Medical Devices	Yes

Building & Landscape

Heating and Cooling	*How old is the existing HVAC system? When is the planned/estimated replacement?* The facility has 24 package units and multiple mini-splits that range in age from brand new to 20 years old
	Does the unit have an air filtration system of at least MERV 13? Yes
Potable Water Sources	Yes
Water Resupply Methods/ Plans	No, not on a regular basis
Resilience to Climate Hazards	*Was the facility built to withstand climate hazards that may impact the site? [Flooding, Drought, Wildfire]* Unknown at this time
Rainwater Harvesting / Water Capture and Filtration	No, potential future systems would need to be investigated for feasibility
Space for Community Garden	Yes, there is an existing community garden

Power

Power Infrastructure	Provided information did not indicate any critical limitation(s) of existing facility circuitry prohibitive to microgrid development. Support

[14] City of Moreno Valley Parks & Community Services. https://moval.gov/parks-comm-svc/senior-services.html
[15] USDN. *Resilience Hubs: Five Foundational Areas*. Resilience Hub Five Foundational Areas

	components are already in-place for connection of an emergency generator (diesel). Available parking lot (i.e., carport) space for photovoltaic array(s) is adequate for onsite generation capacity sufficient to meet or exceed present-day demand. In short, the site is "microgrid-ready." Details available in accompanying *Microgrid Feasibility Study*.
Back-Up Power	Yes

Operations & Maintenance

Emergency Capacity	Yes, the facility is used as an emergency shelter, as well as a cooling/heating center for Riverside County seniors
Emergency Plan	Yes
Security	*Does the facility have a functioning alarm system?* Yes
	Does the facility have secure doors? Yes
	Does the facility have motion-activated lights in areas such as hallways and bathrooms? Yes
ADA Assessment	
Gross Floor Area	43,413 sq ft
No. of people assumed	154
Criteria	Evaluation Notes
Route	**Meets accessibility needs:** A continuous, unobstructed path with gentle or no slopes, providing access from public spaces to the building.
Parking	**Meets accessibility needs:** Site provides an adequate number of accessible parking spaces with properly sized access aisles.
Building entrance	**Meets accessibility needs:** Accessible main entrance or signage is provided to accessible entry.
Restroom clearances	**Meets accessibility needs:** Restrooms include sufficient turning space, and door swings meet accessibility requirements.
Restroom fixture	**Meets accessibility needs:** Fixtures meet accessibility clearance and mounting height requirements.
Interior circulation	**Meets accessibility needs:** Interior pathways are unobstructed.
Multi-story accessibility	**N/A** - Single-story building. All levels of the building are accessible via an elevator or lift.

Services & Programming

Educational Programs	• Social and educational programs, including community workshops and adult learning sessions
Recreation & Wellness	• Adult fitness classes • Nutrition center lunch service for seniors
Programming for Seniors	• Fitness and wellness classes • Resource guide • Transportation programs: MoVan and Dial-a-Ride • Feeding America ongoing food distribution
Emergency Response Training	• Fire suppression and disaster preparedness training for staff • Additional trainings are provided as needed or required for specific positions such as CPR and First Aid
Partnerships	• Feeding America – Nutrition and food assistance programs • Office On Aging – Senior support services and resources • Riverside University Health System – Health and wellness programs • HICAP – Medicare counseling and education • Family Service Association – Social services and community support

Gaps and Recommendations

Site Access

The site is served by public transit, sidewalks, and roadways making the site accessible for populations using a variety of modes within the City of Moreno Valley. Riverside Transit Agency's bus Route 31 has a stop located on Fir Ave directly outside of the Moreno Valley Senior Center that provides access to the east and west into the City of Beaumont and to Mt. San Jacinto College San Jacinto Campus. Additionally, bus Route 19 has a located on adjacent Perris Blvd that provides access north and south to the City of Perris. Sidewalks in the area appear to be in good condition and provide pedestrian access from multiple directions, in addition to connecting to transit stops in the area. Perris Blvd serves as an evacuation route that connects to State Highway-60.

Priority Population Considerations

Over half of the census tracts within the service area are considered "least healthy" by the Healthy Places Index. To better understand the specific chronic conditions, physical health, and mental well-being of the service population, the facility could conduct outreach through surveys and community events that build trust with the community. Once an understanding of the community's health conditions is developed, the facility could incorporate into emergency plans and operations the specific needs of those with chronic health conditions. For example, community members who rely on medications that require refrigeration or medical equipment that require electricity. The facility may continue to provide programing that promotes healthy lifestyles and reduces the risk of chronic health conditions in the community.

The percentage of limited English speakers in the service area is greater compared to the state average. This population may need greater support accessing disaster information and recovery resources. The facility can understand the languages spoken in the community through census data or by conducting outreach with residents. Then informational materials on disaster, educational preparedness, and recovery resources can be created in these languages. For prominent languages spoken in the community it is helpful to have staff at the facility who are able to translate and further support these community members.

The average percentage of children under five in the service area is greater than the state average, meaning there may be more families with young children and infants using the facility during an emergency. To address the needs of children and their families during and after an emergency, the facility could provide childcare services and mental health services focused on trauma support for children during and after an emergency.

The average percentage of women 15 to 50 years who had a birth in the past 12 months in the service area is greater than the state average, meaning there may be more pregnant people using the facility during an emergency. To address the needs of this population, the facility could integrate maternal and child health considerations into emergency plans, provide basic medical services at the facility during and after an emergency, and coordinate with public health agencies and healthcare providers to provide supplies for infant feeding and educational resources for new parents.[16] It is also important to consider if the facility has adequate access to evacuation routes that can connect to a hospital in the case of a pregnancy occurring during or after an emergency. The Moreno Valley Senior Center is located on an evacuation route that can provide access to the interstate and local medical facilities.

[16] U.S. Center for Disease Control. *Reproductive Health – Emergency Preparedness and Response Tools and Resources.* https://www.cdc.gov/reproductive-health/php/emergency-tools/index.html

The average median household income in the service area tracts is lower than the state's. To address the needs of lower-income communities during and after an emergency, the facility can provide services for logistical support for communication with recovery agencies and insurance companies. Additionally, lower-income populations can feel especially stressed about financial planning and providing basic resources for themselves and their family after a disaster. The facility could consider offering or coordinating mental health services for these populations.

Although data on homeless persons is provided at the regional level, homelessness is best understood locally. The facility may consider if there is a visible presence of homeless persons in the service area of the facility, if the population seems to be growing, and if the facility has previously been a resource for homeless persons. This population may need additional support and services when sheltered during an emergency. Strategies to support this population that the facility can consider include coordination with local homeless shelters for disaster preparedness, understanding the capacity of homeless persons in the area the facility may need to support, and providing mental health and medical services.[17]

Building Resilience Checklist

The site area is vulnerable to drought, wildfires, and flooding. The following are suggestions for the facility to build resilience against these hazards.

Drought:

☐ Water conservation measures such as efficient plumbing fixtures and low-flow toilets

☐ Native landscaping and xeriscaping

☐ Recycled water system

Wildfire:

☐ Proper HVAC air filtration for internal air quality (wildfire smoke)

☐ Fire resistant construction that uses non-combustible or fire-resistant building materials for renovations or reconstruction

☐ Fire-resistant plants used in landscaping

Flooding:

☐ Wet floodproofing solutions – engineered flood vents and water-resistant building materials

☐ Dry floodproofing solutions – flood gates, backflow preventers on drains, sealing openings in walls and foundations, sump pumps, and waterproof enclosures

☐ Site perimeter floodproofing – sand bags, water-inflated tube systems and flood panels

☐ Elevated mechanical and electrical equipment to the roof or other areas above the flood level

☐ Stormwater management solutions – permeable pavers, bioswales, and green roofs

Facility Accessibility & Infrastructure

ADA Compliance

All ADA assessment criteria is met for the Moreno Valley Senior Center. There are no further recommendations for the facility to meet compliance. This ADA assessment is based on the building's intended use as defined by its code designation. Additional investigations and

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requirements may be necessary to accommodate emergency lodging, bathing, and waste disposal, as determined by the authority having jurisdiction.

Facility Infrastructure

To support the facility to act as a community resilience center during and after an emergency, the facility can:

- Plan for the storage of and stock a sufficient amount of water resupply in case of a disruption to potable water systems.
- Assess the feasibility of adding a rain garden or capture and filtration system to the facility.

Facility Operations & Disaster Preparedness

The community resilience center staff and volunteers can take steps to integrate processes and training that support the continued operation of the community resilience center in all operating conditions: normal operations, during an event, and after an event. Along with having a facility emergency plan, additional disaster preparedness strategies include the following:

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AECOM

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- Disruption (During Emergency Event) – Provides immediate relief, shelter, and access to resources for residents and community members
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The Perris Senior Center was selected by the City of Perris to be evaluated for its viability to serve as a Community Resilience Center. Feasibility assessment results are presented as follows:

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- Community Profile
- Facility Profile
- Gaps and Recommendations

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Site Profile

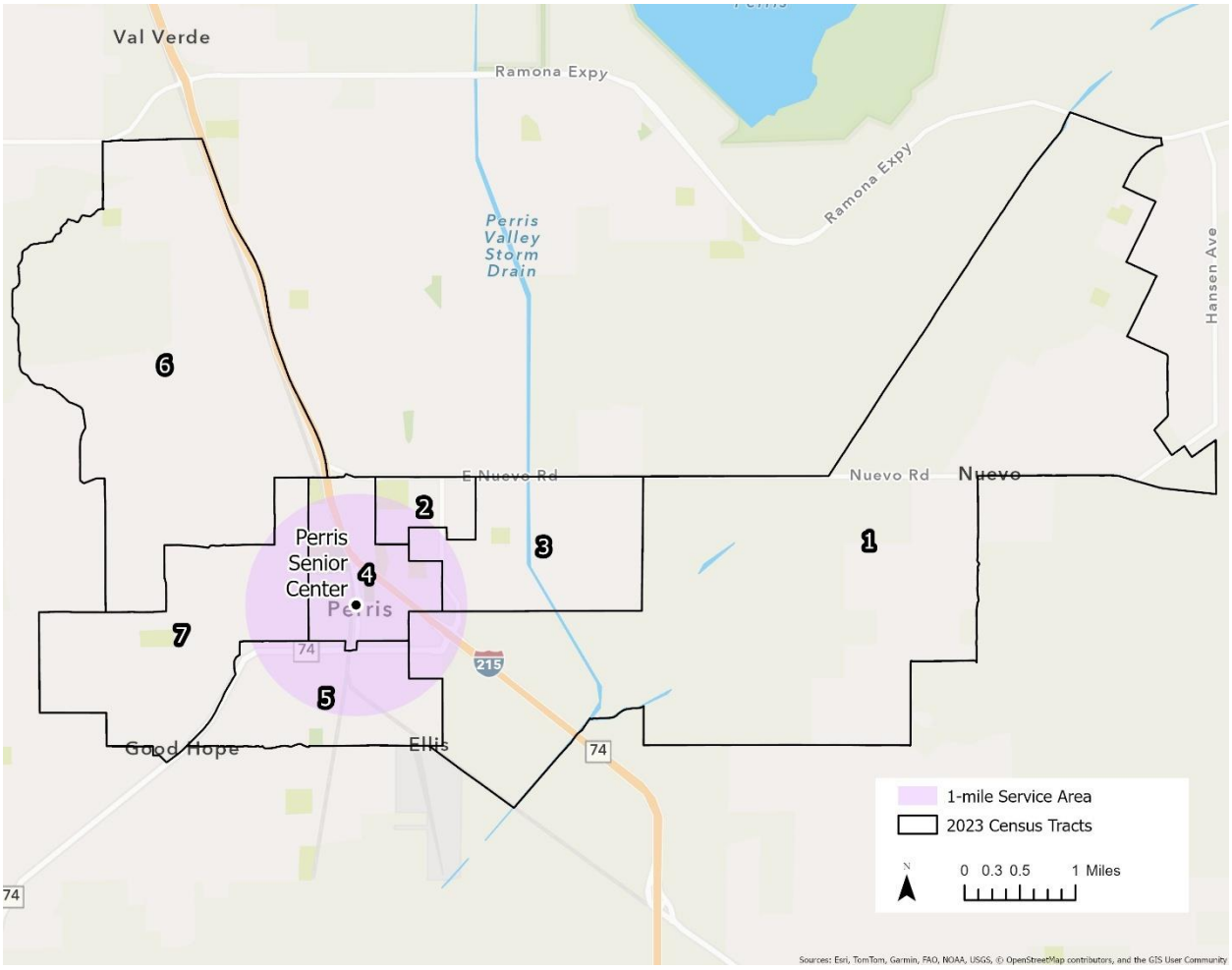


Figure 1. Site Location Map

The Perris Senior Center is located centrally in the City of Perris near Foss Field Park, Perris City Hall, and many other city facilities. For the purpose of the assessment, the service area was determined to be the area within a 1-mile radius of the site (shown in Figure 1). There are seven census tracts that intersect with the service area and these were used to assess the site's climate vulnerability and the community's priority populations (See Table 1 for census tract IDs). However, the census tract boundaries go beyond the service area boundaries. Therefore, characteristics are provided for an area greater than the 1-mile radius from the site.

Table 1 provides the site's accessibility and vulnerability to climate hazards.

Table 1. Site Characteristics

Site Characteristics	Perris Senior Center
Address	100 N D St, Perris, CA 92570
Census Tract IDs (2023)	(1) 06065042719 (2) 06065042746 (3) 06065042747 (4) 06065042801 (5) 06065042802 (6) 06065042905 (7) 06065042908
Climate Vulnerability	**High/Medium Risk Climate Hazards *(one or more tracts above CVI 50th national vulnerability percentile[1])*:** Drought; Wildfire; Flooding **Site Facility in 100-year Floodplain:** No
Pedestrian Accessibility	**Percent of the Service Area within a 15 min Walk to the Facility[2]:** 39% **Major Network/Sidewalk Gaps:** There do not appear to be any major pedestrian sidewalk gaps to access or evacuate the site area. The network is restricted to the west by railroad tracks and privately owned land.
Public Transit Accessibility	**Total Routes Serving the Site Area:** 8 transit routes (1 rail, 7 bus) **Total Stops in the Site Area:** 45 transit stops (2 rail, 43 bus) **Distance to Nearest Stop:** ~0.12 miles to a bus stop on E San Jacinto Ave. ~0.29 miles to the Perris-Downtown Metrolink train station. Pedestrian travel is possible on sidewalks from the senior center to the nearest transit stops.
Proximity to Evacuation Routes or Major Highways	**Close Proximity to Interstate 215:** ~0.6 mile using N D St **Located on an Evacuation Route** (N D St)

[1] The Climate Vulnerability Index (CVI) uses 2010 Census tracts. https://map.climatevulnerabilityindex.org/map/cvi_overall/usa?mapBoundaries=Tract&mapFilter=0&reportBoundaries=Tract&geoContext=State

[2] Walksheds were developed in Urban Footprint and use parcel areas, excluding rights-of-way, to calculate the percent of the service area that is within a 15-minute walk from the facility. Learn more about Urban Footprint software: https://urbanfootprint.com/

Community Profile

The median household incomes of tracts in the surrounding community are on average lower compared to the State's Median Household Income (MHI). All of the census tracts that intersect with the site area are a designated SB 535 Disadvantaged Community determined by the top 25% of CalEnviroScreen 4.0 percentile scores. [3] Table 2 provides the surrounding population size and priority population factors for each tract compared to state averages, noting in red when census tracts are below the state average and noting in green when census tracts are above the state average.

[3] State of California OEHHA. SB 535 Disadvantaged Communities. https://oehha.ca.gov/calenviroscreen/sb535

Table 2. Community Characteristics

Characteristics	Perris Senior Center								
Surrounding Population Size[4]	12,712								
	Census Tracts								
Priority Population Factors	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**Average**	**State Average**
Disabled[5]	9.71%	4.55%	7.93%	11.51%	8.00%	12.49%	11.16%	9.33%	**11.65%**
Chronic Conditions[6]	23rd percentile	17th percentile	17th percentile	6th percentile	6th percentile	5th percentile	12th percentile	**7 of 7 'Least Healthy' Tracts**	**'Least Healthy' below 25th percentile statewide**
Limited English[7]	18.92%	31.46%	26.97%	25.21%	25.99%	33.25%	30.64%	27.50%	**17.08%**
Children Under 5[8]	10.86%	6.33%	5.08%	10.77%	7.36%	6.76%	7.57%	7.82%	**5.44%**
Elderly Over 75[9]	2.20%	1.60%	2.91%	4.07%	1.66%	1.94%	2.68%	2.44%	**6.66%**
Pregnant People[10]	15.27%	5.58%	5.25%	0.00%	7.23%	14.42%	5.49%	7.61%	**4.86%**
Low Income[11]	$77,093	$92,830	$82,383	$53,966	$81,250	$77,544	$65,935	$75,859	**$104,103.66**
No Vehicle Access[12]	8.87%	0.00%	7.56%	12.99%	6.80%	11.44%	15.76%	9.06%	**7.15%**
Homelessness[13]	In January 2024 the Riverside City and County CoC had a total of 4,249 homeless persons, 57% of which were not sheltered by emergency shelter or transitional housing. Comparatively, 34% of the state of California's homeless population was not sheltered by emergency shelter or transitional housing.								

[4] The service population was calculated using 2020 Census blocks within the 1-mile service area. Some of the blocks included in this calculation go beyond the service area boundary. Blocks that intersect with the service area but do not have a significant portion of the block within the service area were excluded.
[5] ACS 5-year 2019-2023 Census: Disabled Populations
[6] Healthy Places Index (HPI)
[7] ACS 5-year 2019-2023 Census: Language Spoken at Home for the Population 5 Years and Over
[8] ACS 5-year 2019-2023 Census: Sex & Age
[9] ACS 5-year 2019-2023 Census: Sex & Age
[10] ACS 5-year 2019-2023 Census: Women 15 to 50 Years Who Had a Birth in the Past 12 Months
[11] ACS 5-year 2019-2023 Census: Median Household Income
[12] ACS 5-year 2019-2023 Census: Households with No Vehicle
[13] The U.S. Department of Housing and Urban Development reports on homelessness from point-in-time information by Continuums of Care (CoCs) that provides counts for sheltered and unsheltered homeless persons by household type and subpopulation. For more information see https://www.hudexchange.info/programs/coc/coc-homeless-populations-and-subpopulations-reports/.

Facility Profile

The Perris Senior Center offers weekly recreational activities, exercise classes, and a daily lunch program for adults seniors aged 50 and older.[14] The following tables provide an overview of the results of the facility evaluation for criteria that were developed under the USDN five foundational areas of resilience hubs: Communications, Building & Landscape, Power, Operations & Maintenance, and Services & Programming.[15] Green rows indicate criteria is met, and red rows indicate criteria is not met.

Communications

Broadband Access	Yes
Wired-Phone / Satellite Phone	Yes, the facility has multiple wired phones available
Ability to Charge Communication Devices / Medical Devices	Yes

Building & Landscape

Heating and Cooling	*How old is the existing HVAC system? When is the planned/estimated replacement?* The existing HVAC system is two months old.
	Does the unit have an air filtration system of at least MERV 13? Yes
Potable Water Sources	Yes
Water Resupply Methods/ Plans	No
Resilience to Climate Hazards	*Was the facility built to withstand climate hazards that may impact the site? [Flooding, Drought, Wildfire]* No
Rainwater Harvesting / Water Capture and Filtration	No, but there is the ability for one to be installed onsite
Space for Community Garden	Yes

[14] City of Perris. *Senior Center*. https://www.cityofperris.org/our-city/community-info/senior-center
[15] USDN. *Resilience Hubs: Five Foundational Areas*. Resilience Hub Five Foundational Areas

Power

Power Infrastructure	The site has an existing standby emergency generator and associated infrastructure in place. Provided information did not indicate any critical limitation(s) of existing facility circuitry prohibitive to microgrid development. In short, the site is “microgrid-ready.” Details available in accompanying Microgrid Feasibility Study.
Back-Up Power	Yes

Operations & Maintenance

Emergency Capacity	The facility is used as a Public Safety Power Shutoff (PSPS) site location resource for residents and a cooling center during hotter months.
Emergency Plan	No
Security	*Does the facility have a functioning alarm system?* Yes
	Does the facility have secure doors? Yes
	Does the facility have motion-activated lights in areas such as hallways and bathrooms? Yes
ADA Assessment	
Gross Floor Area	Unknown at this time
No. of people assumed	50-100
Criteria	Evaluation Notes
Route	**Meets accessibility needs:** A continuous, unobstructed path with gentle or no slopes, providing access from public spaces to the building.
Parking	**Meets accessibility needs:** Site provides an adequate number of accessible parking spaces with properly sized access aisles.
Building entrance	**Meets accessibility needs:** Accessible main entrance or signage is provided to accessible entry.
Restroom clearances	**Meets accessibility needs:** Restrooms include sufficient turning space, and door swings meet accessibility requirements.
Restroom fixture	**Meets accessibility needs:** Fixtures meet accessibility clearance and mounting height requirements.
Interior circulation	**Meets accessibility needs:** Interior pathways are unobstructed.
Multi-story accessibility	**N/A** - Single-story building. All levels of the building are accessible via an elevator or lift.

Services & Programming

Educational Programs	• Nutrition class
Recreation & Wellness	• Weekly recreational activities • Exercise classes
Programming for Seniors	• Daily lunch program • Bingo/Card Games • Art classes
Emergency Response Training	• CERT • LISTOS • Active shooter training • CPR/AED/First Aid Training. • FEMA training for staff • EOC training for staff • Shelter fundamental training for staff
Partnerships	• JAR Insurance – offers services such as free programming, celebration giveaways, monetary sponsorships to assist with events, resources, and information on medical plans. • VVUSD and PUHSD school districts – partnership to use facilities during an activation

Gaps and Recommendations

Site Access

The site is served by public transit, sidewalks, and roadways making the site accessible for populations using a variety of modes within the City of Perris. Riverside Transit Agency's bus Routes 27 and 19 have a stop located on E San Jacinto Ave less than a quarter of a mile from the Perris Senior Center that provides access to the Perris-Downtown Metrolink train station, among other destinations. Sidewalks in the area appear to be in good condition and provide pedestrian access from multiple directions, in addition to connecting to transit stops in the area. The Senior Center is located on an evacuation route that connects to Interstate 215.

To the west of the Senior Center vehicle and pedestrian access is restricted by railroad tracks and a large parcel of private property. The facility can consider if residents in these areas with less direct access may come to the facility during an emergency, if there is another community resilience center in these areas, or if a secondary or alternate location for the community resilience center needs to be established that has better access from those areas.

Priority Population Considerations

All of the census tracts within the service area are considered "least healthy" by the Healthy Places Index. To better understand the specific chronic conditions, physical health, and mental well-being of the service population, the facility could conduct outreach through surveys and community events that build trust with the community. Once an understanding of the community's health conditions is developed, the facility could incorporate into emergency plans and operations the specific needs of those with chronic health conditions. For example, community members who rely on medications that require refrigeration or medical equipment that require electricity. The facility may continue to provide programing that promotes healthy lifestyles and reduces the risk of chronic health conditions in the community.

The percentage of limited English speakers in the service area is greater compared to the state average. This population may need greater support accessing disaster information and recovery resources. The facility can understand the languages spoken in the community through census data or by conducting outreach with residents. Then informational materials on disaster, educational preparedness, and recovery resources can be created in these languages. For prominent languages spoken in the community it is helpful to have staff at the facility who are able to translate and further support these community members.

The average percentage of children under five in the service area is greater than the state average, meaning there may be more families with young children and infants using the facility during an emergency. To address the needs of children and their families during and after an emergency, the facility could provide childcare services and mental health services focused on trauma support for children during and after an emergency.

The average percentage of women 15 to 50 years who had a birth in the past 12 months in the service area is greater than the state average, meaning there may be more pregnant people using the facility during an emergency. To address the needs of this population, the facility could integrate maternal and child health considerations into emergency plans, provide basic medical services at the facility during and after an emergency, and coordinate with public health agencies and healthcare providers to provide supplies for infant feeding and educational resources for new parents.[16] It is also important to consider if the facility has adequate access to evacuation routes that can connect to a hospital in the case of a pregnancy occurring during or

[16] U.S. Center for Disease Control. *Reproductive Health – Emergency Preparedness and Response Tools and Resources.* https://www.cdc.gov/reproductive-health/php/emergency-tools/index.html

after an emergency. The Perris Senior Center is located on an evacuation route that can provide access to the interstate and local medical facilities.

The average median household income in the service area tracts is lower than the state's. To address the needs of lower-income communities during and after an emergency, the facility can provide services for logistical support for communication with recovery agencies and insurance companies. Additionally, lower-income populations can feel especially stressed about financial planning and providing basic resources for themselves and their family after a disaster. The facility could consider offering or coordinating mental health services for these populations.

The average percentage of households with no vehicle in the service area is greater than the state average, meaning a larger percentage of the population may be relying on access from alternative modes of transportation to access the site. The Perris Senior Center is located within half a mile from a bus stop and the Perris-Downtown Metrolink train station, making access using public transit a viable option for these populations. The facility can coordinate with the Riverside Transit Agency and Southern California Regional Rail Authority to be informed when these modes are not viable during or after an emergency so other plans can be made for this population, such as carpooling.

Although data on homeless persons is provided at the regional level, homelessness is best understood locally. The facility may consider if there is a visible presence of homeless persons in the service area of the facility, if the population seems to be growing, and if the facility has previously been a resource for homeless persons. This population may need additional support and services when sheltered during an emergency. Strategies to support this population that the facility can consider include coordination with local homeless shelters for disaster preparedness, understanding the capacity of homeless persons in the area the facility may need to support, and providing mental health and medical services.[17]

Building Resilience Checklist

The site area is vulnerable to drought, wildfires, and flooding. The following are suggestions for the facility to build resilience against these hazards.

Drought:

☐ Water conservation measures such as efficient plumbing fixtures and low-flow toilets

☐ Native landscaping and xeriscaping

☐ Recycled water system

Wildfire:

☐ Proper HVAC air filtration for internal air quality (wildfire smoke)

☐ Fire resistant construction that uses non-combustible or fire-resistant building materials for renovations or reconstruction

☐ Fire-resistant plants used in landscaping

Flooding:

☐ Wet floodproofing solutions – engineered flood vents and water-resistant building materials

☐ Dry floodproofing solutions – flood gates, backflow preventers on drains, sealing openings in walls and foundations, sump pumps, and waterproof enclosures

[17] U.S. Housing and Development. *Disaster Recovery – Homelessness Toolkit.* https://files.hudexchange.info/resources/documents/DR-H-Preparedness-Checklist-Shelter-and-Services.pdf

☐ Site perimeter floodproofing – sandbags, water-inflated tube systems and flood panels

☐ Elevated mechanical and electrical equipment to the roof or other areas above the flood level

☐ Stormwater management solutions – permeable pavers, bioswales, and green roofs

Facility Accessibility & Infrastructure

ADA Compliance

All ADA assessment criteria is met for the Perris Senior Center. There are no further recommendations for the facility to meet compliance. This ADA assessment is based on the building's intended use as defined by its code designation. Additional investigations and requirements may be necessary to accommodate emergency lodging, bathing, and waste disposal, as determined by the authority having jurisdiction.

Facility Infrastructure

To support the facility to act as a community resilience center during and after an emergency, the facility can: water resupply, rain harvesting, emergency plan

- Plan for the storage of and stock a sufficient amount of water resupply in case of a disruption to potable water systems.
- Assess the feasibility of adding a rain garden or capture and filtration system to the facility.
- Develop an emergency plan for the facility and understand the capacity the facility has to serve the community during an emergency, whether that be as an emergency shelter or as a hub for sharing information and coordination.

Facility Operations & Disaster Preparedness

The community resilience center staff and volunteers can take steps to integrate processes and training that support the continued operation of the community resilience center in all operating conditions: normal operations, during an event, and after an event. Along with having a facility emergency plan, additional disaster preparedness strategies include the following:

- Determine appropriate and functional communication channels with the community to notify them the community resilience center is open, alert them of emergency updates, coordinate resources, and share general information.
- Identify key personnel and what role they will have in each of the operating modes.
- Identify and provide training for key personnel to increase preparedness and knowledge.
- Identify and provide training for community members to increase community adaptive capacity.
- Identify funding and partnerships to support key personnel in operating the community resilience center.

Additional Resources

Community resilience and disaster preparedness are broad topics with many detailed best practices and approaches. In addition to some key strategies summarized above, the following resources provide tools and guidance to prepare for disaster and build community resilience:

- Bay Localize, 2020. *Community Resilience Toolkit* (Link)

- Central Coast Climate Collaborative, 2025. What is a Community Resilience Hub? (Link)
- District of Columbia Department of Energy and Environment, 2025. Community Resilience Hubs (Link)
- U.S. Department of Homeland Security, 2025. *People with Disabilities* (Link)
- Urban Sustainability Directors Network, 2017. *Guide to Equitable, Community-Driven Climate Preparedness Planning* (Link)
- Urban Sustainability Directors Network, 2019. *Guide to Developing Resilience Hubs* (Link)

Community Resilience Center Feasibility Study

City of Riverside

Ysmael Villegas Community Center

February 2026

Delivering a better world

Introduction

In recent years, communities across the Inland Empire have experienced increasingly severe climate hazard conditions, including, but not limited to, wildfires, extreme heat, extreme winds, and flash flooding. Consequently, community resources and utility services continue to face frequent and impactful disruptions across Riverside County.

In 2023, the Western Riverside Council of Governments (WRCOG) was awarded a grant under the Integrated Climate Adaptation and Resiliency Program from the Governor's Office of Land Use and Climate Innovation to develop an *Energy Resilience Plan 2.0*. The grant project includes feasibility studies for Community Resilience Centers for WRCOG member agencies.

Community Resilience Center – Permanent community-serving facility equipped to support residents and coordinate essential resource distribution and services before, during, and after an emergency event

Distinct from an emergency shelter, a Community Resilience Center serves as a year-round resource hub that can be activated for response functions during emergency events. It is defined by the infrastructure and building components (e.g., backup power, air filtration, alternate communications), service functions (e.g., community gathering, social programming), and accessibility that support community resilience in both business-as-usual and emergency scenarios, typified in these prototypical modes of operation:

- Steady State – Acts in ordinary community-serving capacity (e.g., community center, senior center, fire station)
- Disruption (During Emergency Event) – Provides immediate relief, shelter, and access to resources for residents and community members
- Recovery (Post-Emergency) – Can serve as a central location for resource distribution, mutual aid and volunteer coordination, etc.

The Ysmael Villegas Community Center was selected by the City of Riverside to be evaluated for its viability to serve as a Community Resilience Center. Feasibility assessment results are presented as follows:

- Site Profile
- Community Profile
- Facility Profile
- Gaps and Recommendations

This document is intended to serve the City of Riverside with first step analysis in identifying an opportunity to improve community resilience. The *Energy Resilience Plan 2.0* provides further guidance on resilience strategies and implementation considerations.

From the Governor's Office of Land Use and Climate Innovation

As communities in California experience more frequent, prolonged, and severe impacts from climate change, communities and governments at all scales are developing strategies and implementing actions to build a climate- resilient future. However, many jurisdictions, especially under-resourced communities in California, lack the capacity, tools, guidance, and resources to effectively prepare for climate impacts.

The Adaptation Planning Grant Program addresses this capacity gap by providing funding to help fill planning needs, providing communities with the resources to identify climate resilience priorities, and supporting the development of climate resilience projects across the state. The Adaptation Planning Grant Program enables communities to climate risk and adaptation considerations into planning activities and prepare for climate readiness and resilience in the long term.

The Adaptation Planning Grant is part of the Integrated Climate Adaptation and Resiliency Program (ICARP) housed within the Governor's Office of Land Use and Climate Innovation (LCI). ICARP advances statewide climate adaptation and resilience by coordinating investments, partnerships, and climate science to ensure people, natural systems, and the built environment are protected, prepared, and thrive in the face of climate change.

Through direct and equity-focused investments and resources, ICARP helps build climate adapted and equitable communities in California, with a focus on solutions that address the impacts of climate change and reduce greenhouse gas emissions. ICARP works to advance these priorities across all levels of government by developing actionable science and research; providing guidance, tools, and technical assistance; and administering climate resilience-focused grant programs.

Learn more: https://lci.ca.gov/climate/icarp/

Site Profile

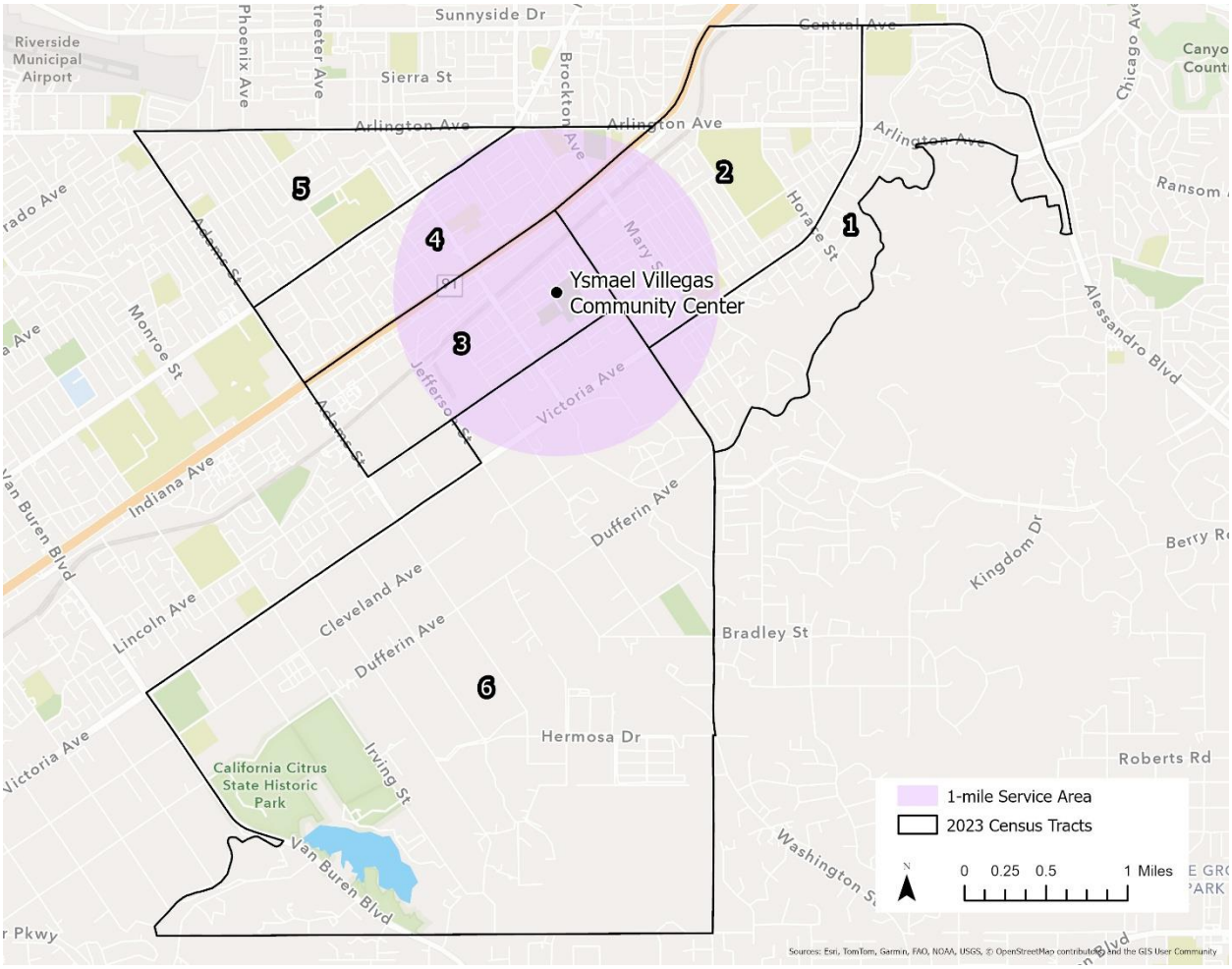


Figure 1. Site Location Map

The Ysmael Villegas Community Center is located in the southeast of the City of Riverside in the Casa Blanca neighborhood next to Villegas Park and State Highway 91. For the purpose of the assessment, the service area was determined to be the area within a 1-mile radius of the site (shown in Figure 1). There are six census tracts that intersect with the service area and these were used to assess the site's climate vulnerability and the community's priority populations (See Table 1 for census tract IDs). However, the census tract boundaries go beyond the service area boundaries. Therefore, characteristics are provided for an area greater than the 1-mile radius from the site.

Table 1
Table 1 provides the site's accessibility and vulnerability to climate hazards.

Table 1. Site Characteristics

Site Characteristics	Ysmael Villegas Community Center
Address	3091 Esperanza St, Riverside, CA 92504
Census Tract IDs (2023)	(1) 06065030602 (2) 06065031200 (3) 06065031300 (4) 06065031401 (5) 06065031402 (6) 06065031701
Climate Vulnerability	**High/Medium Risk Climate Hazards *(one or more tracts above CVI 50th national vulnerability percentile[1])*:** Drought; Wildfire; Flooding **Site Facility in 100-year Floodplain:** No
Pedestrian Accessibility	**Percent of the Service Area within a 15 min Walk to the Facility[2]:** 39% **Major Network/Sidewalk Gaps:** Pedestrian access is disconnected to the south of the site due to Esperanza St not intersecting with Lincoln Ave, a primary road to the south of the site area. To access the site from the south, Madison St (west) or Washington St (east) is used to connect from Lincoln Ave. There is not sidewalk on either side of Washington St.
Public Transit Accessibility	**Total Routes Serving the Site Area:** 4 transit routes **Total Stops in the Site Area:** 32 transit stops **Distance to Nearest Stop:** Around 0.6 miles to each of the closest two transit stops, north and south of the community center. Pedestrian travel on sidewalks is possible for a majority of the route.
Proximity to Evacuation Routes or Major Highways	**Close Proximity to State Highway 91:** ~0.58 mile using Ysmael Villegas St and Madison St **Close Proximity to Evacuation Routes:** ~0.25 mile to Madison St.; ~0.56 mile to Mary St

[1] The Climate Vulnerability Index (CVI) uses 2010 Census tracts. https://map.climatevulnerabilityindex.org/map/cvi_overall/usa?mapBoundaries=Tract&mapFilter=0&reportBoundaries=Tract&geoContext=State

[2] Walksheds were developed in Urban Footprint and use parcel areas, excluding rights-of-way, to calculate the percent of the service area that is within a 15-minute walk from the facility. Learn more about Urban Footprint software: https://urbanfootprint.com/

Community Profile

The median household incomes of tracts in the surrounding community are on average lower compared to the State's Median Household Income (MHI). Half (3 of 6) of the census tracts that intersect with the site area are a designated SB 535 Disadvantaged Community determined by the top 25% of CalEnviroScreen 4.0 percentile scores.[3] Table 2 provides the surrounding population size and priority population factors for each tract compared to state averages, noting in red when census tracts are below the state average and noting in green when census tracts are above the state average.

Table 2. Community Characteristics

Characteristics	Ysmael Villegas Community Center							
Surrounding Population Size[4]	11,726							
Priority Population Factors	**Census Tracts** 1	2	3	4	5	6	**Average**	**State Average**
Disabled[5]	16.07%	9.49%	10.89%	13.07%	11.50%	22.16%	**13.86%**	**11.65%**
Chronic Conditions[6]	64th percentile	48th percentile	11th percentile	24th percentile	24th percentile	22nd percentile	**4 of 6 'Least Healthy' Tracts**	**'Least Healthy' below 25th percentile statewide**
Limited English[7]	1.30%	7.59%	32.78%	15.38%	9.27%	26.36%	**15.45%**	**17.08%**
Children Under 5[8]	0.62%	5.00%	6.63%	5.70%	6.53%	4.79%	**4.88%**	**5.44%**
Elderly Over 75[9]	8.20%	4.07%	3.33%	3.99%	6.71%	7.91%	**5.70%**	**6.66%**
Pregnant People[10]	0%	8.91%	0%	1.73%	5.87%	2.39%	**3.15%**	**4.86%**
Low Income[11]	$135,685	$97,238	$75,774	$81,164	$68,906	$81,467	**$90,039**	**$104,103**
No Vehicle Access[12]	3.23%	1.71%	9.11%	6.87%	9.41%	3.22%	**5.60%**	**7.15%**
Homelessness[13]	In January 2024 the Riverside City and County CoC had a total of 4,249 homeless persons, 57% of which were not sheltered by emergency shelter or transitional housing. Comparatively, 34% of the state of California's homeless population was not sheltered by emergency shelter or transitional housing.							

[3] State of California OEHHA. SB 535 Disadvantaged Communities. https://oehha.ca.gov/calenviroscreen/sb535
[4] The surrounding population size was calculated using 2020 Census blocks within the 1-mile service area. Some of the blocks included in this calculation go beyond the service area boundary. Blocks that intersect with the service area but do not have a significant portion of the block within the service area were excluded.
[5] ACS 5-year 2019-2023 Census: Disabled Populations
[6] Healthy Places Index (HPI)
[7] ACS 5-year 2019-2023 Census: Language Spoken at Home for the Population 5 Years and Over
[8] ACS 5-year 2019-2023 Census: Sex & Age
[9] ACS 5-year 2019-2023 Census: Sex & Age
[10] ACS 5-year 2019-2023 Census: Women 15 to 50 Years Who Had a Birth in the Past 12 Months
[11] ACS 5-year 2019-2023 Census: Median Household Income
[12] ACS 5-year 2019-2023 Census: Households with No Vehicle
[13] The U.S. Department of Housing and Urban Development reports on homelessness from point-in-time information by Continuums of Care (CoCs) that provides counts for sheltered and unsheltered homeless persons by household type and subpopulation. For more information see https://www.hudexchange.info/programs/coc/coc-homeless-populations-and-subpopulations-reports/.

Facility Profile

The Ysmael Villegas Community Center is a single-story building designed to provide year-round services and programs to the community and act as a hub for community information sharing and coordination during and after emergencies. The following tables provide an overview of the results of the facility evaluation for criteria that were developed under the USDN five foundational areas of resilience hubs: Communications, Building & Landscape, Power, Operations & Maintenance, and Services & Programming.[14] Green rows indicate criteria is met, and red rows indicate criteria is not met.

Communications

Broadband Access	Yes
Wired-Phone / Satellite Phone	*Does the facility have a wired or satellite phone available?* Unknown at this time
Ability to Charge Communication Devices / Medical Devices	Yes

Building & Landscape

Heating and Cooling	*How old is the existing HVAC system? When is the planned/estimated replacement?* The unit does not need to be replaced for another 10+ years.
	Does the unit have an air filtration system of at least MERV 13? No
Potable Water Sources	Yes
Water Resupply Methods/ Plans	No
Resilience to Climate Hazards	*Was the facility built to withstand climate hazards that may impact the site? [Flooding, Drought, Wildfire]* Unknown at this time
Rainwater Harvesting / Water Capture and Filtration	No - do not have a capture and filtration system but do have room for one to be installed onsite.
Space for Community Garden	Yes

Power

Power Infrastructure	The site is currently equipped to be powered via a portable diesel generator. Provided information did not indicate any critical limitation(s) of existing facility circuitry prohibitive to microgrid development. In short, the site is “microgrid-ready.” Details available in accompanying *Microgrid Feasibility Study*.

[14] USDN. *Resilience Hubs: Five Foundational Areas*. Resilience Hub Five Foundational Areas

Back-Up Power	No

Operations & Maintenance

Emergency Capacity	During and after emergencies the facility is available as a community hub for information sharing and coordination.
Emergency Plan	Yes
Security	*Does the facility have a functioning alarm system?* Yes
	Does the facility have secure doors? Yes
	Does the facility have motion-activated lights in areas such as hallways and bathrooms? No
ADA Assessment	
Gross Floor Area	Approximately 24,000 sq. ft.
No. of people assumed	2,300
Criteria	Evaluation Notes
Route	**Meets accessibility needs:** A continuous, unobstructed path with gentle or no slopes, providing access from public spaces to the building.
Parking	**Meets accessibility needs:** Site provides an adequate number of accessible parking spaces with properly sized access aisles.
Building entrance	**Meets accessibility needs:** Accessible main entrance or signage is provided to accessible entry.
Restroom clearances	**Meets accessibility needs:** Restrooms include sufficient turning space, and door swings meet accessibility requirements.
Restroom fixture	**Meets accessibility needs:** Fixtures meet accessibility clearance and mounting height requirements.
Interior circulation	**Meets accessibility needs:** Interior pathways are unobstructed.
Multi-story accessibility	**N/A** - Single-story building. All levels of the building are accessible via an elevator or lift.

Services & Programming

Educational Programs	• After School Program • English as a second language (ESL)

Recreation & Wellness	• Pickleball • Aerobics
Programming for Seniors	• Eldertainment — a series of social enrichment activities for seniors
Emergency Response Training	• Staff receive ongoing training through the City of Riverside Parks, Recreation, and Community Services Department on general safety, facility procedures, and emergency response protocols. • There is not a site-specific emergency preparedness training program but staff are familiar with departmental emergency procedures and communication channels to follow before, during, and after an emergency. • The site is working to collaborate with the City's Emergency Management Department to provide additional hands-on training and preparedness workshops tailored to community center operations and public response during emergencies.
Partnerships	• **NRPA** offers the Walk with Ease walking program to support arthritis management and overall physical health. • **Inland Caregivers** provides monthly PEARLS presentations to support senior mental health and wellness. • **Local farm partnership** will offer health and education classes focused on nutrition and food access.

Gaps and Recommendations

Site Access

To address the gap in pedestrian access to the south of the site between Esperanza St and Lincoln Ave, the facility could work with the City of Riverside and developers of the lot that impedes connection to explore options for a pedestrian pathway along the east side the lot. Creating this connection will improve pedestrian access to the Community Center and improve access to the Madison St evacuation route and the transit stops on Lincoln Ave. Additionally, a more thorough assessment of sidewalk condition and network gaps could be conducted to better understand how accessible the site is for pedestrians.

Walkability between the Community Center and transit stops in the area could be improved. Washington Street provides access to the two closest transit stops, but does not have sidewalk on both sides of the road between Lincoln Ave and Indiana Ave. The facility can work with the City of Riverside to integrate new sidewalk construction into road improvement plans to create a complete sidewalk network that enables safe access to the site from public transit and pedestrians from nearby neighborhoods.

Priority Population Considerations

While the census data shows that the service area's average percent of the population that is disabled is greater the state average, the types of disabilities are not known. This assessment focused on the accessibility (ADA compliance) of the facility itself. The facility can coordinate with the local transit or rideshare provider for accessible transportation to and from the facility and provide back-up power for those who use medical equipment that requires electricity. The facility may need to work with the City of Riverside to review sidewalk accessibility, as well as conduct outreach with residents to evaluate additional accessibility needs.

Over half of the census tracts within the service area are considered "least healthy" by the Healthy Places Index. To better understand the specific chronic conditions, physical health, and mental well-being of the service population, the facility could conduct outreach through surveys and community events that build trust with the community. Once an understanding of the community's health conditions is developed, the facility could incorporate into emergency plans and operations the specific needs of those with chronic health conditions. For example, community members who rely on medications that require refrigeration or medical equipment that require electricity. The Community Center may continue to provide programing that promotes healthy lifestyles and reduces the risk of chronic health conditions in the community.

The average median household income in the service area tracts is lower than the state's. To address the needs of lower-income communities during and after an emergency, the facility can provide services for logistical support for communication with recovery agencies and insurance companies. Additionally, lower-income populations can feel especially stressed about financial planning and providing basic resources for themselves and their family after a disaster. The facility could consider offering or coordinating mental health services for these populations.

Although data on homeless persons is provided at the regional level, homelessness is best understood locally. The facility may consider if there is a visible presence of homeless persons in the service area of the facility, if the population seems to be growing, and if the facility has previously been a resource for homeless persons. This population may need additional support and services when sheltered during an emergency. Strategies to support this population that the facility can consider include coordination with local homeless shelters for disaster preparedness,

understanding the capacity of homeless persons in the area the facility may need to support, and providing mental health and medical services.[15]

Building Resilience Checklist

The site area is vulnerable to drought, wildfires, and flooding. The following are suggestions for the facility to build resilience against these hazards.

Drought:

☐ Water conservation measures such as efficient plumbing fixtures and low-flow toilets

☐ Native landscaping and xeriscaping

☐ Recycled water system

Wildfire:

☐ Proper HVAC air filtration for internal air quality (wildfire smoke)

☐ Fire resistant construction that uses non-combustible or fire-resistant building materials for renovations or reconstruction

☐ Fire-resistant plants used in landscaping

Flooding:

☐ Wet floodproofing solutions – engineered flood vents and water-resistant building materials

☐ Dry floodproofing solutions – flood gates, backflow preventers on drains, sealing openings in walls and foundations, sump pumps, and waterproof enclosures

☐ Site perimeter floodproofing – sand bags, water-inflated tube systems and flood panels

☐ Elevated mechanical and electrical equipment to the roof or other areas above the flood level

☐ Stormwater management solutions – permeable pavers, bioswales, and green roofs

Facility Accessibility & Infrastructure

ADA Compliance

All ADA assessment criteria are met for the Ysmael Villegas Community Center. There are no further recommendations for the facility to meet compliance. This ADA assessment is based on the building's intended use as defined by its code designation. Additional investigations and requirements may be necessary to accommodate emergency lodging, bathing, and waste disposal, as determined by the authority having jurisdiction.

Facility Infrastructure

To support the facility to act as a community resilience center during and after an emergency, the facility can:

- Install a back-up power generator to prepare for power outages that often result from natural disasters and extreme weather events.
- Plan for the storage of and stock a sufficient amount of water resupply in case of a disruption to potable water systems.

[15] U.S. Housing and Development. *Disaster Recovery – Homelessness Toolkit.* https://files.hudexchange.info/resources/documents/DR-H-Preparedness-Checklist-Shelter-and-Services.pdf

- Install adequate air filtration of at least MERV 13 or higher to the HVAC system to maintain indoor air quality in the event of wildfire smoke in the area.
- Assess the feasibility of adding a rain garden or capture and filtration system to the facility.
- Install motion-activated lights in areas such as hallways and bathrooms for added security inside the facility.

Facility Operations & Disaster Preparedness

The community resilience center staff and volunteers can take steps to integrate processes and training that support the continued operation of the community resilience center in all operating conditions: normal operations, during an event, and after an event. Along with having a facility emergency plan, additional disaster preparedness strategies include the following:

- Determine appropriate and functional communication channels with the community to notify them the community resilience center is open, alert them of emergency updates, coordinate resources, and share general information.
- Identify key personnel and what role they will have in each of the operating modes.
- Identify and provide training for key personnel to increase preparedness and knowledge.
- Identify and provide training for community members to increase community adaptive capacity.
- Identify funding and partnerships to support key personnel in operating the community resilience center.

Additional Resources

Community resilience and disaster preparedness are broad topics with many detailed best practices and approaches. In addition to some key strategies summarized above, the following resources provide tools and guidance to prepare for disaster and build community resilience:

- Bay Localize, 2020. *Community Resilience Toolkit* (Link)
- Central Coast Climate Collaborative, 2025. What is a Community Resilience Hub? (Link)
- District of Columbia Department of Energy and Environment, 2025. Community Resilience Hubs (Link)
- U.S. Department of Homeland Security, 2025. *People with Disabilities* (Link)
- Urban Sustainability Directors Network, 2017. *Guide to Equitable, Community-Driven Climate Preparedness Planning* (Link)
- Urban Sustainability Directors Network, 2019. *Guide to Developing Resilience Hubs* (Link)

AECOM

Community Resilience Center Feasibility Study

City of Wildomar

City Hall

February 2026

Delivering a better world

Introduction

In recent years, communities across the Inland Empire have experienced increasingly severe climate hazard conditions, including, but not limited to, wildfires, extreme heat, extreme winds, and flash flooding. Consequently, community resources and utility services continue to face frequent and impactful disruptions across Riverside County.

In 2023, the Western Riverside Council of Governments (WRCOG) was awarded a grant under the Integrated Climate Adaptation and Resiliency Program from the Governor's Office of Land Use and Climate Innovation to develop an *Energy Resilience Plan 2.0*. The grant project includes feasibility studies for Community Resilience Centers for WRCOG member agencies.

Community Resilience Center – Permanent community-serving facility equipped to support residents and coordinate essential resource distribution and services before, during, and after an emergency event

Distinct from an emergency shelter, a Community Resilience Center serves as a year-round resource hub that can be activated for response functions during emergency events. It is defined by the infrastructure and building components (e.g., backup power, air filtration, alternate communications), service functions (e.g., community gathering, social programming), and accessibility that support community resilience in both business-as-usual and emergency scenarios, typified in these prototypical modes of operation:

- Steady State – Acts in ordinary community-serving capacity (e.g., community center, senior center, fire station)
- Disruption (During Emergency Event) – Provides immediate relief, shelter, and access to resources for residents and community members
- Recovery (Post-Emergency) – Can serve as a central location for resource distribution, mutual aid and volunteer coordination, etc.

The Wildomar City Hall was selected by the City of Wildomar to be evaluated for its viability to serve as a Community Resilience Center. Feasibility assessment results are presented as follows:

- Site Profile
- Community Profile
- Facility Profile
- Gaps and Recommendations

This document is intended to serve the City of Wildomar with first step analysis in identifying an opportunity to improve community resilience. The *Energy Resilience Plan 2.0* provides further guidance on resilience strategies and implementation considerations.

From the Governor's Office of Land Use and Climate Innovation

As communities in California experience more frequent, prolonged, and severe impacts from climate change, communities and governments at all scales are developing strategies and implementing actions to build a climate- resilient future. However, many jurisdictions, especially under-resourced communities in California, lack the capacity, tools, guidance, and resources to effectively prepare for climate impacts.

The Adaptation Planning Grant Program addresses this capacity gap by providing funding to help fill planning needs, providing communities with the resources to identify climate resilience priorities, and supporting the development of climate resilience projects across the state. The Adaptation Planning Grant Program enables communities to climate risk and adaptation considerations into planning activities and prepare for climate readiness and resilience in the long term.

The Adaptation Planning Grant is part of the Integrated Climate Adaptation and Resiliency Program (ICARP) housed within the Governor's Office of Land Use and Climate Innovation (LCI). ICARP advances statewide climate adaptation and resilience by coordinating investments, partnerships, and climate science to ensure people, natural systems, and the built environment are protected, prepared, and thrive in the face of climate change.

Through direct and equity-focused investments and resources, ICARP helps build climate adapted and equitable communities in California, with a focus on solutions that address the impacts of climate change and reduce greenhouse gas emissions. ICARP works to advance these priorities across all levels of government by developing actionable science and research; providing guidance, tools, and technical assistance; and administering climate resilience-focused grant programs.

Learn more: https://lci.ca.gov/climate/icarp/

Site Profile

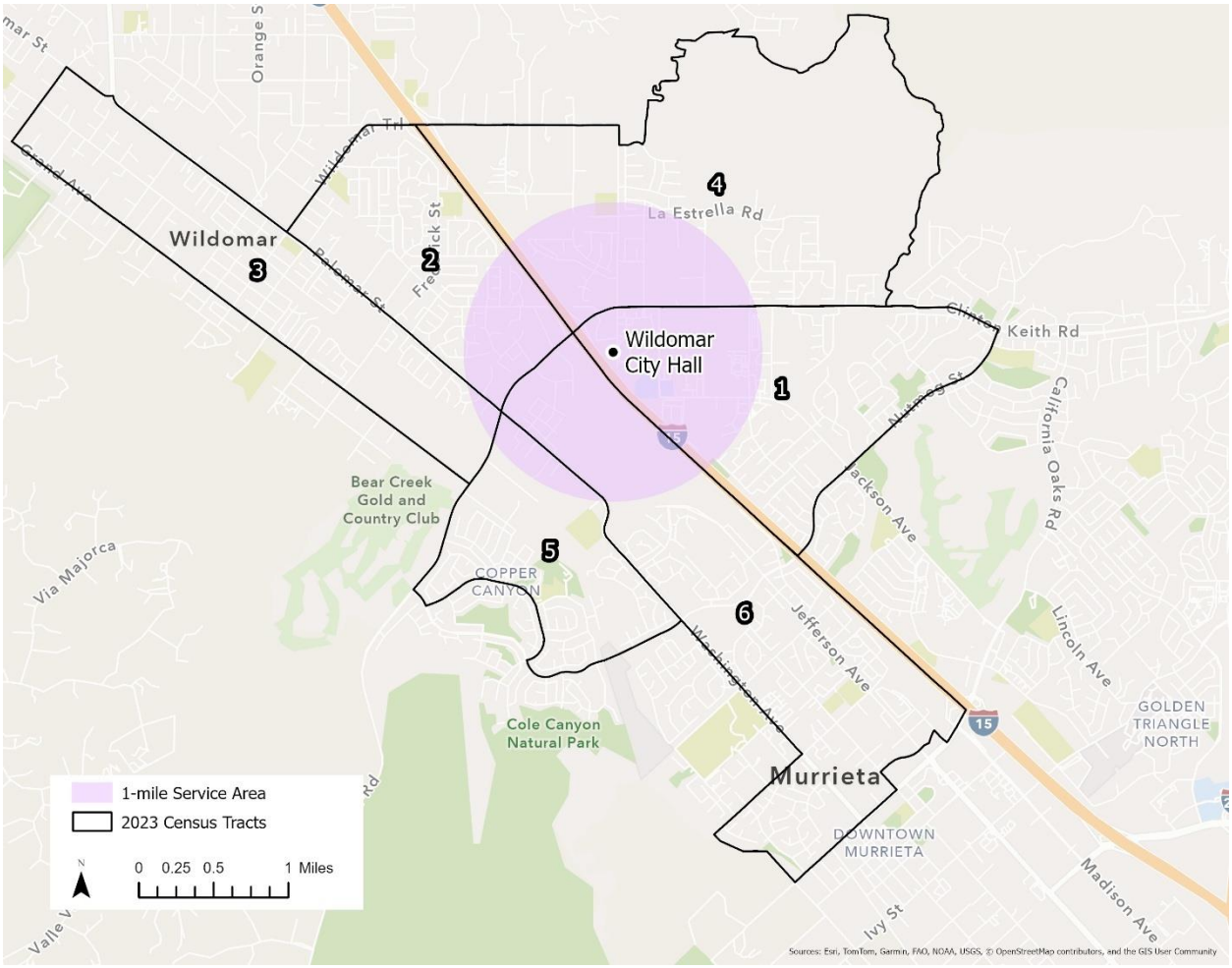


Figure 1. Site Location Map

The Wildomar City Hall is located in the southern portion of the City of Wildomar at the intersection of Interstate-15 and Clinton Keith Road. For the purpose of the assessment, the service area was determined to be the area within a 1-mile radius of the site (shown in Figure 1). There are six census tracts that intersect with the service area and these were used to assess the site's climate vulnerability and the community's priority populations (See Table 1 for census tract IDs). However, the census tract boundaries go beyond the service area boundaries. Therefore, characteristics are provided for an area greater than the 1-mile radius from the site.

Table 1 provides the site's accessibility and vulnerability to climate hazards.

Table 1. Site Characteristics

Site Characteristics	Wildomar City Hall
Address	23873 Clinton Keith Rd, STE 201, Wildomar, CA 92595
Census Tract IDs (2023)	(1) 06065043227 (2) 06065043270 (3) 06065043271 (4) 06065043276 (5) 06065049701 (6) 06065050600
Climate Vulnerability	**High/Medium Risk Climate Hazards *(one or more tracts above CVI 50th national vulnerability percentile[1])*:** Drought; Wildfire; Flooding **Site Facility in 100-year Floodplain:** No
Pedestrian Accessibility	**Percent of the Service Area within a 15 min Walk to the Facility[2]:** 10% **Major Network/Sidewalk Gaps:** There appears to be a continuous sidewalk in the service area along Clinton Keith Rd and within the Oak Creek S Center Shopping Mall where the City Hall is located. Wildomar Trail behind the facility has sidewalk along a majority of the road, but there is a gap in sidewalk at the first 0.15 miles of the road closest to City Hall. Neighborhoods to the east of City Hall can comfortably access the facility by walking on sidewalks. Neighborhoods across Clinton Keith Road will have to cross this 8-lane road, but do have adequate sidewalk infrastructure to do so. Neighborhoods to the west of City Hall will have to cross Insterate-15 using the Clinton Keith Rd overpass to access the site.
Public Transit Accessibility	**Total Routes Serving the Site Area:** 2 transit routes **Total Stops in the Site Area:** 9 transit stops **Distance to Nearest Stop:** Less than half a mile using Wildomar Trail to the closest transit stops located at Clinton Keith Rd and Wildomar Trail. There is sidewalk on a majority of Wildomar Trail so pedestrian travel between City Hall and the transit stops is feasible.
Proximity to Evacuation Routes or Major Highways	**Close Proximity to Interstate 15:** ~0.74 mile using Oak Creek Mall and Clinton Keith Rd. **Close Proximity to Evacuation Routes:** ~0.32 mile to Clinton Keith Rd using Oak Creek Mall

[1] The Climate Vulnerability Index (CVI) uses 2010 Census tracts. https://map.climatevulnerabilityindex.org/map/cvi_overall/usa?mapBoundaries=Tract&mapFilter=0&reportBoundaries=Tract&geoContext=State

[2] Walksheds were developed in Urban Footprint and use parcel areas, excluding rights-of-way, to calculate the percent of the service area that is within a 15-minute walk from the facility. Learn more about Urban Footprint software: https://urbanfootprint.com/

Community Profile

The median household incomes of tracts in the surrounding community are on average higher compared to the State's Median Household Income (MHI). Additionally, none of the six census tracts that intersect with the site area are a designated SB 535 Disadvantaged Community determined by the top 25% of CalEnviroScreen 4.0 percentile scores.[3] Table 2 provides the surrounding population size and priority population factors for each tract compared to state averages, noting in red when census tracts are below the state average and noting in green when census tracts are above the state average.

Table 2. Community Characteristics

Characteristics	Wildomar City Hall							
Surrounding Population Size[4]	5,242							
	Census Tracts							
Priority Population Factors	**1**	**2**	**3**	**4**	**5**	**6**	**Average**	**State Average**
Disabled[5]	11.90%	15.28%	10.58%	6.84%	3.43%	11.12%	**9.86%**	**11.65%**
Chronic Conditions[6]	57th percentile	36th percentile	35th percentile	46th percentile	72nd percentile	51st percentile	**0 of 6 'Least Healthy' Tracts**	**'Least Healthy' below 25th percentile statewide**
Limited English[7]	4.89%	10.52%	16.27%	5.01%	1.39%	4.23%	**7.05%**	**17.08%**
Children Under 5[8]	4.64%	5.02%	9.26%	4.69%	12.86%	6.77%	**7.21%**	**5.44%**
Elderly Over 75[9]	4.31%	6.60%	4.35%	3.67%	3.87%	7.24%	**5.01%**	**6.66%**
Pregnant People[10]	5.25%	4.92%	6.03%	0.00%	16.02%	1.39%	**5.60%**	**4.86%**
Low Income[11]	$120,938	$99,917	$124,063	$147,742	$158,285	$106,000	**$126,158**	**$104,103.66**
No Vehicle Access[12]	0.39%	15.36%	4.76%	1.37%	0.00%	6.43%	**4.72%**	**7.15%**
Homelessness[13]	In January 2024 the Riverside City and County CoC had a total of 4,249 homeless persons, 57% of which were not sheltered by emergency shelter or transitional housing. Comparatively, 34% of the state of California's homeless population was not sheltered by emergency shelter or transitional housing.							

[3] State of California OEHHA. SB 535 Disadvantaged Communities. https://oehha.ca.gov/calenviroscreen/sb535
[4] The service population was calculated using 2020 Census blocks within the 1-mile service area. Some of the blocks included in this calculation go beyond the service area boundary. Blocks that intersect with the service area but do not have a significant portion of the block within the service area were excluded.
[5] ACS 5-year 2019-2023 Census: Disabled Populations
[6] Healthy Places Index (HPI)
[7] ACS 5-year 2019-2023 Census: Language Spoken at Home for the Population 5 Years and Over
[8] ACS 5-year 2019-2023 Census: Sex & Age
[9] ACS 5-year 2019-2023 Census: Sex & Age
[10] ACS 5-year 2019-2023 Census: Women 15 to 50 Years Who Had a Birth in the Past 12 Months
[11] ACS 5-year 2019-2023 Census: Median Household Income
[12] ACS 5-year 2019-2023 Census: Households with No Vehicle
[13] The U.S. Department of Housing and Urban Development reports on homelessness from point-in-time information by Continuums of Care (CoCs) that provides counts for sheltered and unsheltered homeless persons by household type and subpopulation. For more information see https://www.hudexchange.info/programs/coc/coc-homeless-populations-and-subpopulations-reports/.

Facility Profile

The Wildomar City Hall is a two-story building in the Oak Creek Center Shopping Mall. The following tables provide an overview of the results of the facility evaluation for criteria that were developed under the USDN five foundational areas of resilience hubs: Communications, Building & Landscape, Power, Operations & Maintenance, and Services & Programming.[14] Green rows indicate criteria is met, and red rows indicate criteria is not met.

Communications

Broadband Access	Yes
Wired-Phone / Satellite Phone	Yes - City Hall staff have satellite phones on site as well as HAM radio
Ability to Charge Communication Devices / Medical Devices	No

Building & Landscape

Heating and Cooling	*How old is the existing HVAC system? When is the planned/estimated replacement?* The system was installed in 2007 and half of the system will be replaced in 2026.
	Does the unit have an air filtration system of at least MERV 13? Unknown at this time
Potable Water Sources	Yes
Water Resupply Methods/ Plans	Yes
Resilience to Climate Hazards	*Was the facility built to withstand climate hazards that may impact the site? [Flooding, Drought, Wildfire]* Yes - the facility was built to an elevation above the Base Flood Elevation (BFE)
Rainwater Harvesting / Water Capture and Filtration	No
Space for Community Garden	No

Power

Power Infrastructure	The site has an existing standby emergency generator and associated infrastructure in place. Provided information did not indicate any critical limitation(s) of existing facility circuitry prohibitive to microgrid development. In short, the site is “microgrid-ready.” Details available in accompanying Microgrid Feasibility Study.

[14] USDN. *Resilience Hubs: Five Foundational Areas*. Resilience Hub Five Foundational Areas

Back-Up Power	No

Operations & Maintenance

Emergency Capacity	The facility is not currently used as an evacuation or emergency shelter but it does house the City of Wildomar Emergency Operations Center (EOC)
Emergency Plan	Yes
Security	*Does the facility have a functioning alarm system?* No
	Does the facility have secure doors? Yes
	Does the facility have motion-activated lights in areas such as hallways and bathrooms? Yes
ADA Assessment	
Gross Floor Area	~22,000 sq ft.
No. of people assumed	149
Criteria	Evaluation Notes
Route	**Meets accessibility needs:** A continuous, unobstructed path with gentle or no slopes, providing access from public spaces to the building.
Parking	**Meets accessibility needs:** Site provides an adequate number of accessible parking spaces with properly sized access aisles.
Building entrance	**Meets accessibility needs:** Accessible main entrance or signage is provided to accessible entry.
Restroom clearances	**Meets accessibility needs:** Restrooms include sufficient turning space, and door swings meet accessibility requirements.
Restroom fixture	**Meets accessibility needs:** Fixtures meet accessibility clearance and mounting height requirements.
Interior circulation	**Meets accessibility needs:** Interior pathways are unobstructed.
Multi-story accessibility	**Meets accessibility needs:** All levels of the building are accessible via an elevator or lift.

Services & Programming

Educational Programs	• City Hall hosts monthly council and commission meetings, regional trainings, and multiple HOA/POA/non-profit organization meetings
Recreation & Wellness	• None identified
Programming for Seniors	• None identified
Emergency Response Training	• LISTOS emergency preparedness • Staff emergency response training
Partnerships	• None at this time

Gaps and Recommendations

Site Access

The site is served by public transit, sidewalks, and roadways making the site accessible for populations using a variety of modes within the City of Wildomar. Riverside Transit Agency's bus Route 23 has a stop located on Clinton Keith Rd accessible by walking from City Hall that provides access to and from areas in the City of Wildomar and the City of Murrieta. Additionally, Route 206 provides regional access through the City of Wildomar but does not have any stops within the service area.

Sidewalks in the area appear to be in good condition and provide pedestrian access from the east, north, and south, however a more thorough assessment of sidewalk condition and network gaps could be conducted to better understand how accessible the site is for pedestrians. The sidewalk network between the City Hall and the transit stops on Clinton Keith Rd could be improved by addressing the 0.15 mile gap in sidewalk on Wildomar Trail. The City of Wildomar could work with property and right-of-way owners to add sidewalks that could provide safer pedestrian access to transit and evacuation routes.

Priority Population Considerations

The average percentage of children under five in the service area is greater than the state average, meaning there may be more families with young children and infants using the facility during an emergency. To address the needs of children and their families during and after an emergency, the facility could provide childcare services and mental health services focused on trauma support for children during and after an emergency.

The average percentage of women 15 to 50 years who had a birth in the past 12 months in the service area is greater than the state average, meaning there may be more pregnant people using the facility during an emergency. To address the needs of this population, the facility could integrate maternal and child health considerations into emergency plans, provide basic medical services at the facility during and after an emergency, and coordinate with public health agencies and healthcare providers to provide supplies for infant feeding and educational resources for new parents.[15] It is also important to consider if the facility has adequate access to evacuation routes that can connect to a hospital in the case of a pregnancy occurring during or after an emergency.

Although data on homeless persons is provided at the regional level, homelessness is best understood locally. The facility may consider if there is a visible presence of homeless persons in the service area of the facility, if the population seems to be growing, and if the facility has previously been a resource for homeless persons. This population may need additional support and services when sheltered during an emergency. Strategies to support this population that the facility can consider include coordination with local homeless shelters for disaster preparedness, understanding the capacity of homeless persons in the area the facility may need to support, and providing mental health and medical services.[16]

[15] U.S. Center for Disease Control. *Reproductive Health – Emergency Preparedness and Response Tools and Resources.* https://www.cdc.gov/reproductive-health/php/emergency-tools/index.html
[16] U.S. Housing and Development. *Disaster Recovery – Homelessness Toolkit.* https://files.hudexchange.info/resources/documents/DR-H-Preparedness-Checklist-Shelter-and-Services.pdf

Building Resilience Checklist

The site area is vulnerable to drought, wildfires, and flooding. The following are suggestions for the facility to build resilience against these hazards.

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☐ Water conservation measures such as efficient plumbing fixtures and low-flow toilets

☐ Native landscaping and xeriscaping

☐ Recycled water system

Wildfire:

☐ Proper HVAC air filtration for internal air quality (wildfire smoke)

☐ Fire resistant construction that uses non-combustible or fire-resistant building materials for renovations or reconstruction

☐ Fire-resistant plants used in landscaping

Flooding:

☐ Wet floodproofing solutions – engineered flood vents and water-resistant building materials

☐ Dry floodproofing solutions – flood gates, backflow preventers on drains, sealing openings in walls and foundations, sump pumps, and waterproof enclosures

☐ Site perimeter floodproofing – sand bags, water-inflated tube systems and flood panels

☐ Elevated mechanical and electrical equipment to the roof or other areas above the flood level

☐ Stormwater management solutions – permeable pavers, bioswales, and green roofs

Facility Accessibility & Infrastructure

ADA Compliance

All ADA assessment criteria is met for the Wildomar City Hall. There are no further recommendations for the facility to meet compliance. This ADA assessment is based on the building's intended use as defined by its code designation. Additional investigations and requirements may be necessary to accommodate emergency lodging, bathing, and waste disposal, as determined by the authority having jurisdiction.

Facility Infrastructure

To support the facility to act as a community resilience center during and after an emergency, the facility can:

- Install a back-up power generator to prepare for power outages that often result from natural disasters and extreme weather events.
- Install a power system that allows for device charging capabilities for cell phones, personal communication devices, medical devices, power wheelchairs, and other assistive devices and technology.
- Install adequate air filtration of at least MERV 13 or higher to the HVAC system to maintain indoor air quality in the event of wildfire smoke in the area, if the facility is found to not have proper air filtration.
- Assess the feasibility of adding a rain garden or capture and filtration system to the facility.

- Consider the feasibility of partnering with a nearby HOA or POA to create a community garden that can build community and provide fresh food.
- Install an alarm system for added security inside the facility.

Facility Operations & Disaster Preparedness

The community resilience center staff and volunteers can take steps to integrate processes and training that support the continued operation of the community resilience center in all operating conditions: normal operations, during an event, and after an event. Along with having a facility emergency plan, additional disaster preparedness strategies include the following:

- Determine appropriate and functional communication channels with the community to notify them the community resilience center is open, alert them of emergency updates, coordinate resources, and share general information.
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Additional Resources

Community resilience and disaster preparedness are broad topics with many detailed best practices and approaches. In addition to some key strategies summarized above, the following resources provide tools and guidance to prepare for disaster and build community resilience:

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Attachment

WRCOG Energy Resilience Plan 2.0 Implementation Plan

FEBRUARY 2026

MICROGRIDS & COMMUNITY RESILIENCE CENTERS **IMPLEMENTATION PLAN**

AECOM

610

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Disclaimer

This Implementation Plan is intended to serve as a non-binding guidance framework for WRCOG member agencies.

The strategies, phases, timelines, and actions described herein are illustrative and advisory in nature. Adoption, funding, sequencing, and execution of any activities remain at the sole discretion of each individual member agency and are subject to local governance, budget approvals, and regulatory requirements.

Acknowledgements

City of Banning

City of Eastvale

City of Moreno Valley

County of Riverside

City of Beaumont

City of Jurupa Valley

City of Perris

California Governor's Office of Land Use and Climate Innovation

City of Canyon Lake

City of Lake Elsinore

City of Riverside

GRID Alternatives

City of Corona

City of Minefee

City of Wildomar

Inland Regional Energy Network

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EXECUTIVE SUMMARY

The Western Riverside Council of Governments (WRCOG) was awarded a grant under the Integrated Climate Adaptation and Resiliency Program from the California Governor's Office of Land Use and Climate Innovation to develop this Implementation Plan for developing microgrids and Community Resilience Centers for use by its member agencies.

Available funding and financing mechanisms for implementation of microgrids and CRCs in WRCOG member agencies are identified and detailed herein.

This document is supported by the Adaptation Planning Grant Program implemented by the Governor's Office of Planning and Research.

This document is interactive. Use the navigation bar on the left to move between sections.

MICROGRIDS

1 **Feasibility**
Load profiling and economic modeling for a technical "Go/No-Go" decision.

2 **Engineering**
Precise technical blueprints, electrical designs, and control logic.

3 **Permitting**
Utility interconnection and local building code approvals.

4 **Construction**
Procurement and physical installation of distributed energy resources.

5 **Commissioning**
System integration and testing for final handover.

COMMUNITY RESILIENCE CENTERS

1 **Foundation & Team Assembly**
Coordinate city departments and define a community-focused vision.

2 **Site Selection & Vulnerability Assessment**
Map climate risks and social vulnerabilities to select the optimal site.

3 **Design & Service Planning**
Engineer resilience systems and plan services based on resident needs.

4 **Governance & Operational Framework**
Establish legal agreements and protocols for emergency modes.

5 **Funding, Procurement, & Construction**
Secure project funding and execute physical building retrofits.

6 **Launch & Long-Term Stewardship**
Test systems and initiate community-wide programming.

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BACKGROUND

Energy Resilience Plan 2.0

WRCOG

In recent years, communities across the Inland Empire have experienced increasingly severe climate hazard conditions, including, but not limited to, wildfires, extreme heat, extreme winds, flash flooding, and drought. Consequently, community resources and utility services continue to face frequent and impactful disruptions across Riverside County.

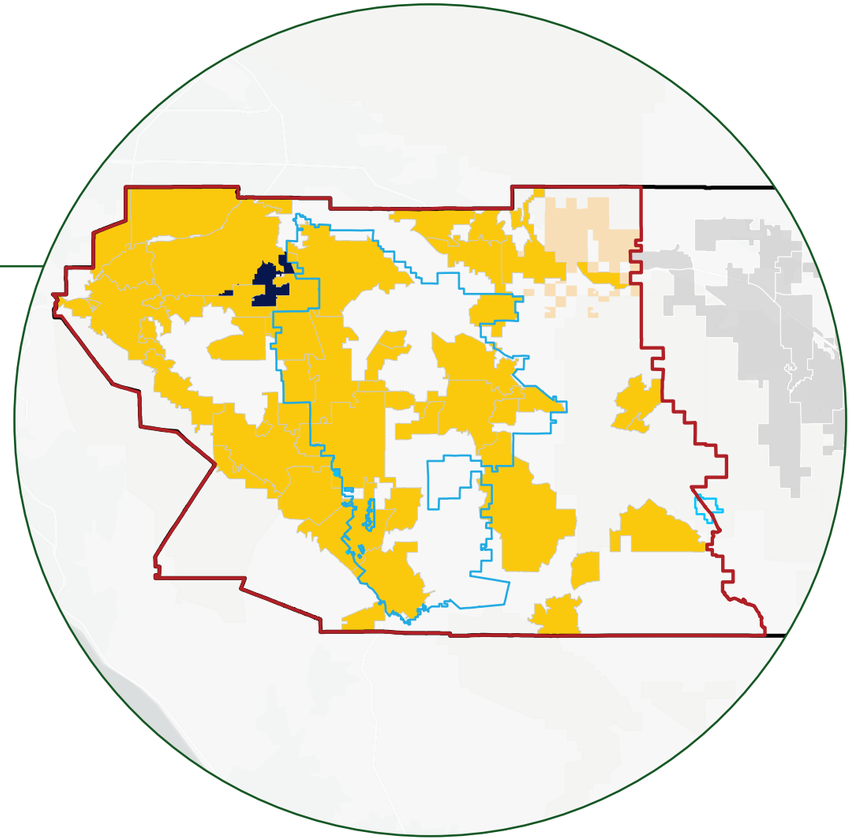
In 2023, the Western Riverside Council of Governments (WRCOG) was awarded a grant under the Integrated Climate Adaptation and Resiliency Program from the Governor's Office of Land Use and Climate Innovation to develop an Energy Resilience Plan 2.0. Project products comprise the following:

1. **Implementation Plan**
2. **Funding & Financing Strategies**
3. **Feasibility Studies**
   - Microgrid (Appendix B)
   - Community Resilience Center (Appendix C)

WRCOG commissioned these Energy Resilience Plan 2.0 products to serve its member agencies as foundational resources for consideration, and eventual establishment, of microgrids and community resilience centers in respective jurisdictions.



County of Riverside
California



WRCOG Member Agencies
Banning, Beaumont, Calimesa, Canyon Lake, Corona, Eastvale, Hemet, Jurupa Valley, Lake Elsinore, Menifee, Moreno Valley, Murrieta, Norco, Perris, Riverside, San Jacinto, Temecula, Wildomar, County of Riverside, Eastern Municipal Water District, Western Municipal Water District, Morongo Band of Mission Indians, Riverside County Superintendent of Schools

WRCOG

Western Municipal Water District

Eastern Municipal Water District

WRCOG Member Cities

Morongo Band of Mission Indians

In 2022, WRCOG developed the original Energy Resilience Plan in response to increasing power outages.

The Energy Resilience Plan served as a guidance document that member agencies could use to plan for investments into existing buildings to reduce impacts from power outages and improve community resilience.

Adaptation Planning Grant Program

Governor's Office of Land Use and Climate Innovation

As communities in California experience more frequent, prolonged, and severe impacts from climate change, communities and governments at all scales are developing strategies and implementing actions to build a climate-resilient future. However, many jurisdictions, especially under-resourced communities in California, lack the capacity, tools, guidance, and resources to effectively prepare for climate impacts.

The Adaptation Planning Grant Program addresses this capacity gap by providing funding to help fill planning needs, providing communities with the resources to identify climate resilience priorities, and supporting the development of climate resilience projects across the state. The Adaptation Planning Grant Program enables communities to climate risk and adaptation considerations into planning activities and prepare for climate readiness and resilience in the long term.

The Adaptation Planning Grant is part of the Integrated Climate Adaptation and Resiliency Program (ICARP) housed within the Governor's Office of Land Use and Climate Innovation. ICARP advances statewide climate adaptation and resilience by coordinating investments, partnerships, and climate science to ensure people, natural systems, and the built environment are protected, prepared, and thrive in the face of climate change.

Through direct and equity-focused investments and resources, ICARP helps build climate adapted and equitable communities in California, with a focus on solutions that address the impacts of climate change and reduce greenhouse gas emissions. ICARP works to advance these priorities across all levels of government by developing actionable science and research; providing guidance, tools, and technical assistance; and administering climate resilience-focused grant programs.

Learn more: https://lci.ca.gov/climate/icarp

Microgrids

Microgrids can provide a decentralized defense against climate hazards by "islanding" from the utility grid during emergencies. Often leveraging on-site power generation (e.g., solar photovoltaic [PV] array, generator set) and battery energy storage systems, they can maintain continuous power for designated critical loads at a facility, district, or community.

This independence can be especially crucial during wildfire season, allowing communities to bypass Public Safety Power Shutoffs (PSPS). By utilizing smart controllers to prioritize critical loads and bypassing vulnerable transmission lines, microgrids can ensure that essential services like water pumping and emergency communications remain operational throughout extended disruptions.

Beyond improving resilience, microgrids can provide auxiliary benefits such as lowering energy costs through peak shaving, reducing carbon emissions by integrating renewable energy sources, and strengthening the greater utility grid by providing ancillary services like frequency regulation and voltage support.

MICROGRIDS

Interconnected system of loads and energy resources, including, but not limited to, distributed energy resources, energy storage, demand response tools, or other management, forecasting, and analytical tools, appropriately sized to meet customer needs, within a clearly defined electrical boundary that can act as a single, controllable entity, and can connect to, disconnect from, or run in parallel with, larger portions of the electrical grid, or can be managed and isolated to withstand larger disturbances and maintain electrical supply to connected critical infrastructure

California Public Utilities Code § 8370

Microgrids can provide a decentralized defense against climate hazards by "islanding" from the utility grid during emergencies.

DISCLAIMER

Potential grid services revenue is highly site- and utility-specific. Within Southern California Edison's service territory, most municipal microgrids operate under non-export or limited-export interconnection agreements and do not meet the minimum dispatchable capacity thresholds, typically on the order of 1 MW, required for participation in wholesale energy or ancillary service markets. Accordingly, participation in grid services markets should not be assumed unless explicitly evaluated and confirmed during the feasibility, interconnection, and market qualification phases.


Photo: EMWD

Eastern Municipal Water District
EMWD has deployed major distributed energy resources, including 21 megawatts (MW) of PV arrays across five facilities, fuel cells using renewable digester gas at the Moreno Valley and Perris Valley Regional Water Reclamation Facilities, eight 60-kilowatt (kW) microturbines, and 2-megwatt-hour (MWh) battery energy storage systems at five facilities.


Photo: Soboba Band of Luiseño Indians / California Energy Commission

Soboba Band of Luiseño Indians Microgrid
Operational as of 2023, this sovereign energy system integrates a 1.5 MW rooftop solar array with a 6 MWh battery storage system at the tribe's Casino Resort. Its primary function is to safeguard tribal commerce and provide a community cooling center and emergency shelter during PSPS.


Photo: NV5

Temecula Valley Unified School District
Established in 2015-2016, this district-wide project consists of 6 MW of solar carports and 2,600 kWh battery storage across 19 sites. Its primary function is to ensure that schools can maintain critical lighting, refrigeration, and communications during grid outages.



Photo: UC Riverside Bourns College of Engineering / CE-CERT

UC Riverside Sustainable Integrated Grid Initiative
Inaugurated in 2014, this "living laboratory" features a 500 kW solar farm, 500 kWh of battery storage, and 8 MW of thermal storage for campus chiller operations. Its primary function is to test "smart" islanding protocols and mobile renewable backup systems that can be deployed to support regional emergency response during catastrophic climate events.

Community Resilience Centers

Distinct from an emergency shelter, a community resilience center serves as a year-round resource hub that can be activated for response functions during emergency events. It is defined by the infrastructure and building components (e.g., backup power, air filtration, alternate communications), service functions (e.g., community gathering, social programming), and accessibility that support community resilience in both business-as-usual and emergency scenarios, typified in these prototypical modes of operation:

Steady State
Acts in ordinary community-serving capacity (e.g., community center, senior center, fire station)

Disruption (During Emergency Event)
Provides immediate relief, shelter, and access to resources for residents and community members

Recovery (Post-Emergency)
Can serve as a central location for resource distribution, mutual aid and volunteer coordination, etc.

COMMUNITY RESILIENCE CENTERS

Permanent community-serving facilities equipped to support residents and coordinate essential resource distribution and services before, during, and after an emergency event.



Photo: City of Coachella / California Strategic Growth Council

Coachella Community Resilience Center
This project involves the renovation of an existing packinghouse into a 17,800-square-foot multifunctional facility that will provide emergency shelter, a cooling center, and year-round community services such as a business incubator and a demonstration kitchen. It is supported by a $10,000,000 Implementation Grant from the California Strategic Growth Council, ensuring the site can support residents during climate emergencies while fostering economic development.



Photo: St. John's Community Health / Totum

Avalon Health Resilience Center
Led by St. John's Community Health, this project establishes a 10,000-square-foot facility in South Los Angeles that integrates medical, dental, and behavioral health care with emergency shelter capabilities. The center was awarded a $10,000,000 Implementation Grant from the California Strategic Growth Council to provide low-income residents with climate-resilient infrastructure, including solar energy and advanced HVAC systems.

Banning Armory CRC Project
The City of Banning is repurposing a 1950s-era armory into a multi-benefit resilience hub and Emergency Operations Center to serve as a high-capacity shelter during extreme heat and natural disasters. This project was awarded a $1,070,620 Project Development Grant from the California Strategic Growth Council to fund facility assessments, electrical retrofitting, and long-term operational planning.



Photo: Record Gazette

Bear Cave Resiliency Operations Center (Washoe Tribe)
The "Hung A Lel Ti t'ába káŋa" (Bear Cave) project is a tribal-led initiative in Alpine County designed to renovate and expand community structures into a gym, fire station, and education center for wildfire and drought preparedness. Funded by a $10,000,000 Implementation Grant from the California Strategic Growth Council, it serves as a critical response hub for the Washoe Tribe of Nevada and California in one of the state's most rural regions.



Photo: Washoe Environmental

EXECUTIVE SUMMARY
BACKGROUND
MICROGRIDS
IMPLEMENTATION PLAN
- FEASIBILITY
- ENGINEERING
- PERMITTING
- CONSTRUCTION
- COMMISSIONING

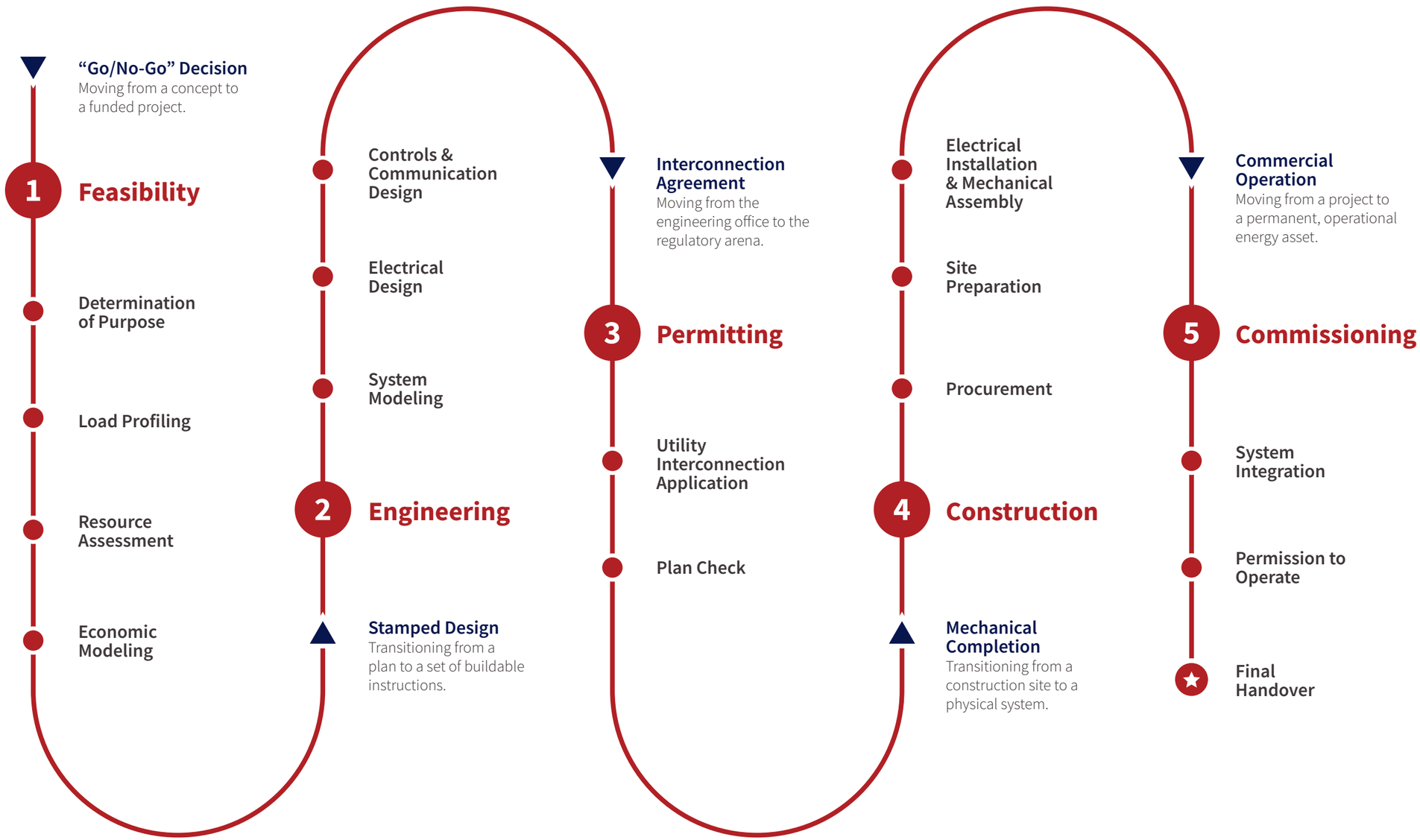
SCHEDULE
VENDORS
CONTRACTING MODELS
COMMUNITY RESILIENCE CENTERS
IMPLEMENTATION PLAN
- FOUNDATION & TEAM ASSEMBLY
- SITE SELECTION & VULNERABILITY ASSESSMENT
- DESIGN & SERVICE PLANNING
- GOVERNANCE & OPERATIONAL FRAMEWORK
- FUNDING, PROCUREMENT, & CONSTRUCTION
- LAUNCH & LONG-TERM STEWARDSHIP

SCHEDULE
VENDORS
FUNDING & FINANCING STRATEGIES

MICROGRIDS

Implementation of microgrids is typically executed in five distinct phases, detailed in subsequent sections.

IMPLEMENTATION PLAN



PHASE 1

FEASIBILITY

The objective of this first phase is to determine if a microgrid is technically viable and financially sound at a specific site. It serves as a “Go/No-Go” before capital is committed to engineering and equipment.

Within each phase, suggested **Inputs**, **Actions**, and **Outputs** are presented for each development stage. Detailed listings are available in Appendix A.

INPUTS **ACTIONS** **OUTPUTS**

Determination of Purpose

Defining the primary purpose of a microgrid at the outset is essential because the specific goal—whether prioritizing resilience, cost savings, or sustainability—fundamentally dictates the system’s size, technology mix, and control logic. Without a clearly ranked set of objectives, a project risks a mismatched design that may excel at reducing utility bills but fail to keep critical loads online during a major grid outage.

To ensure a successful project start, consider ranking these objectives using the following logic:

1. Identify the **Must-Have**
   Choose one primary objective that, if not met, would result in the project being canceled (e.g., “The control room must stay powered for 72 hours”).
2. Identify the **Secondary Benefit**
   Choose the goal that provides the best co-benefit (e.g., “While the system is waiting for an outage, it should reduce demand charges”).
3. Identify the **Trade-Off**
   Acknowledge what you are willing to sacrifice (e.g., “We will accept a longer payback period in exchange for 100% carbon-free resilience”).

Misaligned Stakeholder Goals

COMMON PITFALL

ISSUE
Failing to agree on primary objective(s) early on

IMPACT
Design re-work later in the project, increasing costs

MITIGATION STRATEGY
Facilitate a “Purpose Workshop” with key stakeholders / decision-makers to rank objectives before engineering begins

Table 1 Microgrid Objective Prioritization Matrix

Objective	Primary Driver	Technical Impact	Financial Impact
Resilience	Protecting critical operations against grid outages.	Requires larger battery capacity and "grid-forming" inverters.	Higher CAPEX; insurance-style Value of Resilience (VoR) drives the ROI.
Cost Savings	Reducing utility bills via peak shaving and energy arbitrage.	Requires sophisticated control logic to discharge assets during "peak" hours.	High OPEX savings; ROI is driven by utility tariff avoidance and net metering.
Sustainability	Meeting carbon reduction goals or climate mitigation mandates.	Requires maximum solar/wind or even hydrogen fuel cells or biofuels.	May increase Levelized Cost of Energy (LCOE) initially but secures green tax credits.
Operational Flexibility	Decoupling from the grid to manage local power quality or expansion.	Requires high-speed switching and "Seamless Transition" switchgear.	Protects sensitive equipment; reduces long-term maintenance costs for machinery.
Grid Support	Earning revenue by providing services (e.g., frequency response) to the utility.	Requires utility-interactive software and high-speed communication links.	Creates a revenue stream that can offset the initial cost of the system.

Load Profiling

The purpose of this first technical stage is to establish a high-resolution baseline of how the energy is consumed at the site. This process involves gathering interval data (15-minute, hourly) for a full year (8,760 hours) to identify peak demands, seasonal variances, and other usage trends.

A key exercise at this stage is load criticality categorization to rank electrical assets into tiers based on their operational importance. This ranking is vital because it provides the "instructions" for the microgrid controller to shed non-essential loads during an outage, ensuring that limited power from BESS and generation sources are preserved for the most vital functions.

Table 2 Load Criticality Categorization Tiers

Tier 1	Tier 2	Tier 3
Critical Must never lose power	**Priority Essential** Powered if generation is sufficient	**Interruptible** Shed immediately during an outage

INPUTS
- Interval data
- Utility bills
- Critical load inventory
- Future expansion plan(s)

ACTIONS
- Cleanse raw data
- Categorize loads by criticality
- Model peak demand events

OUTPUTS
- Load profile(s)
- Peak demand report
- Load criticality tiers

Optimistic Load Data
COMMON PITFALL

ISSUE
Using average monthly bills instead of interval data (e.g., 15-minute)

IMPACT
System is undersized and fails during peak loads

MITIGATION STRATEGY
Minimum of 12 months of high-resolution interval data from the utility enables more precise, realistic system sizing

Resource Assessment

The purpose of this stage is to evaluate the production potential of onsite energy generation sources, both existing and prospective.

Existing

Requires collating equipment specifications (e.g., nameplate data), performance data, and existing Interconnection Agreements or Power Purchase Agreements to establish production baselines and identify technical or legal constraints on system modification.

INPUTS
- Asset nameplate data
- O&M logs and health reports
- Existing control architecture

ACTIONS
- Determine controllability
- Evaluate fuel supply chain
- Assess retrofit requirements

OUTPUTS
- Asset integration report
- Operating baseline model
- Interface requirements specifications

Prospective

Requires performing analysis of local environmental data (i.e., solar irradiance, fuel availability, wind resources) alongside physical site constraints like topography and structural integrity. This analysis correlates these findings with historical load data to determine the optimal capacity for new generation assets and Battery Energy Storage Systems (BESS), ensuring the microgrid can consistently meet demand at peak efficiency.

INPUTS
- Site physical surveys
- Solar/wind resource data
- Local utility tariff and interconnection rules

ACTIONS
- Evaluate land and roof suitability
- Calculate capacity factors
- Conduct shading and obstruction analysis

OUTPUTS
- Annual generation potential report
- Site constraints and placement map
- Preliminary technology selection

Economic Modeling

The purpose of this stage is to calculate payback period, internal rate of return, potential savings from "islanded" operations or grid, among other financial metrics. The process can use software like HOMER Pro to simulate configurations to find the system design.

It is at this stage that ownership models for a microgrid can first be considered. Choosing the right ownership model depends on an organization's available capital, tax status, and desire for operational control. These models determine who pays for the equipment, who maintains it, and how the energy is billed over the system's life.

INPUTS
- Capital expenditure (CAPEX) estimates
- Operational expenditure (OPEX) projections
- Incentive and subsidy documentation

ACTIONS
- Cleanse raw data
- Categorize loads by criticality
- Model peak demand events

OUTPUTS
- Financial pro forma statement
- Simple payback and internal rate of return report
- Optimized financing recommendation

Table 3 Microgrid Ownership Models

	Direct Ownership	**Energy Service Agreement (ESA)**	**Power Purchase Agreement (PPA)**
	The facility owner pays the full upfront cost to purchase and install the microgrid, taking complete responsibility for its operation while reaping all financial and tax benefits directly.	A third-party developer finances and owns the system, and the customer pays a service charge based on realized savings or performance, effectively treating energy as an operating expense rather than a capital investment.	A third-party developer installs and owns the microgrid assets on the customer's site and sells the generated electricity back to the customer at a fixed, predetermined rate, usually lower than the utility's retail price.
Primary Advantage (Pros)	Maximum ROI: Owner keeps 100% of energy savings and tax credits.	Pay-for-Performance: Payments are tied to actual savings; the provider handles all O&M.	Zero Upfront Cost: Immediate savings with no initial investment; provider assumes all tech risk.
Primary Disadvantage (Cons)	High Risk: Owner is responsible for all maintenance, repairs, and performance risks.	Complex Contracts: Measuring "savings" can lead to complex accounting and legal negotiations.	Long-Term Commitment: Requires 15–25 year contracts; no direct benefit from tax incentives.
Best For…	Organizations with high capital and tax liability.	Organizations focused on deep energy efficiency and risk transfer.	Non-profits or entities that cannot use tax credits.

PHASE 2

ENGINEERING

In this phase, conceptual designs from the feasibility study are advanced to precise technical blueprints and software logic specifications required for physical construction.



System Modeling

The purpose of stage task is to find the most efficient and cost-effective balance of energy assets through high-resolution mathematical simulation. It entails running scenarios in software (e.g., HOMER Pro, HOMER zGrid, Xendee, REopt) to determine the exact power ratings and storage capacities that minimize energy costs while ensuring the site remains powered during a grid outage.

INPUTS

Refined load and resource data

Technology performance curves

Utility rate structures

ACTIONS

Hourly dispatch simulation

Sensitivity analysis

Verify resilience compliance

OUTPUTS

Finalized system sizing report

Electrical Design

The purpose of this stage is to produce the physical blueprints and technical schematics required for safe, code-compliant construction and utility approval. It generally entails drafting detailed Single-Line Diagrams (SLDs) and equipment layouts that specify wire sizes, circuit breaker ratings, and the physical location of all hardware on the site.

INPUTS

Facility as-built electrical drawings for facility

Equipment data sheets

Site civil and topographical surveys

Local electrical and fire codes

ACTIONS

Draft microgrid SLDs

Protection coordination study

Design interconnection interface

OUTPUTS

Detailed engineering package

In-Accurate Facility As-Builts
COMMON PITFALL

ISSUE

Requisite drawings for the subject are dated/inaccurate, unavailable, or missing

IMPACT

Major change orders and “emergency” redesigns become required during construction

MITIGATION STRATEGY

If necessary, conduct a physical site walkdown and “panel circuit tracing” before finalizing microgrid SLDs

Controls & Communications Design

The purpose of this stage is to architect the "brain" of the microgrid that manages automated operations and the network through which all devices talk. It entails defining the Sequence of Operations (SOO) for islanding events and mapping out the cybersecurity-hardened communication protocols that link the solar, batteries, and meters to the master controller.

Notably, as microgrids become integrated into critical utility and public-sector infrastructure, robust information technology (IT) / operational technology (OT) segmentation and role-based access control are essential to prevent lateral movement of cyber threats between administrative and industrial control systems. Explicitly addressing these security layers during the engineering phase ensures compliance with the increasingly stringent cybersecurity requirements mandated by utilities and water districts. Furthermore, formalizing secure remote access and incident response procedures at the design stage provides a defensive blueprint that protects both physical grid stability and sensitive operational data from evolving digital vulnerabilities.

INPUTS

Sequence of operations (SOO) requirements

Communication protocol list

Existing IT/network infrastructure

ACTIONS

Map data communication paths

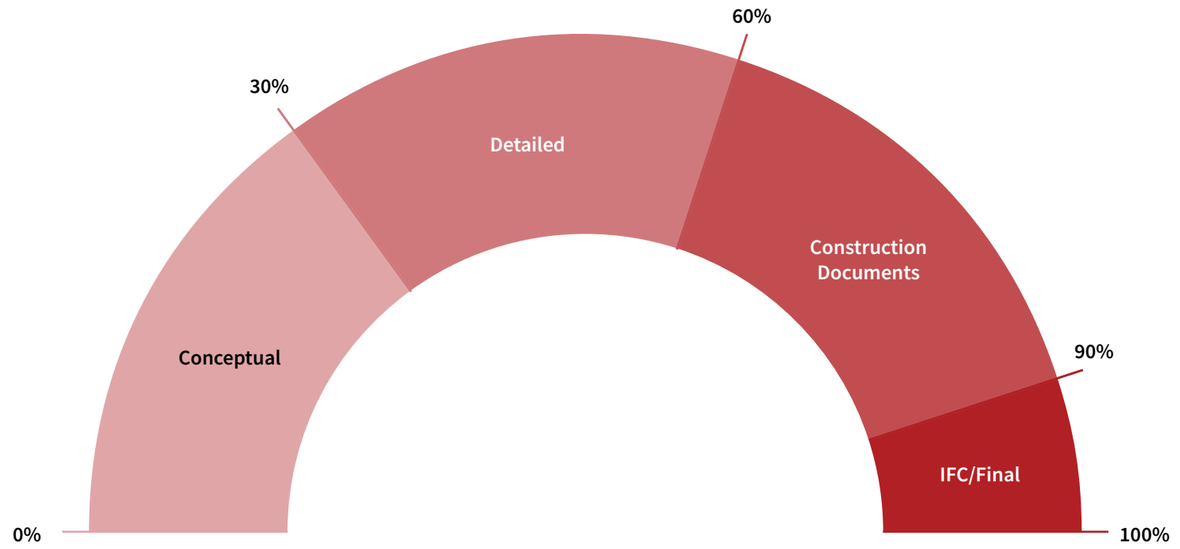
Write automated control logic

Configure human-machine interface (HMI) and monitoring dashboard

OUTPUTS

Control logic and networking map

Table 4 Typical Design Engineering Milestones



Design Set	Included	Not Included	Often Required For	Function by Contracting Model	
				Design-Build	Design-Bid-Build
Conceptual 30%	Preliminary Single Line Diagram (SLD), site plan showing major equipment pads, and utility point of interconnection (POI)	Detailed wiring, conduit routing, or specific control logic programming details	Utility Interconnection Application	Freeze Footprint: Lock in dimensions to order long-lead items	Establish budget and project "Go/No-Go" decision
Detailed 60%	Major cable sizing, grounding plans, structural details for pads, and draft protection settings	Final "as-built" circuit labeling or the full communication/ integration map	Early Procurement & Grading Permits	Civil Release: Start trenching and pouring concrete pads	Coordination between engineering disciplines (Civil/Elec)
Construction Documents 90%	Full bill of materials, detailed conduit schedules, complete structural/fire-safety details, and control sequences	Minor field adjustments or final software setpoints (which occur at the "Issued for Construction" or IFC stage)	Plan Check (Building/ Electrical Permits)	Electrical Release: Begin physical wiring and assembly	Complete set for competitive contractor bidding
IFC/Final 100%	All 90% comments addressed; every page stamped and signed by a Professional Engineer (PE)	Changes requested by the builder during construction (these become "As-Builts" later)	Fire Marshal Review & Final Inspection	System Verification: Finalizing software setpoints and logic	The "Handoff Point" where construction legally begins

PHASE 3

PERMITTING

In this phase, the project moves from the engineering office to the regulatory arena. This phase is often the critical path for the project timeline, as it requires formal approvals from external authorities (e.g., utilities, local governments) before any physical construction can begin.

This phase manages the legal and regulatory hurdles required to operate a private power plant alongside the public utility. Success here is measured by obtaining the legal right to energize the system and export power if applicable.

"Golden Rule" of Microgrid Risk

Many successful projects treat the Utility and the Local Fire Marshal as project partners rather than obstacles. Engaging these entities during the Engineering phase (rather than waiting for the Permitting phase) can reduce the likelihood of a rejected design, and sunk time, effort, and expenses, significantly.

Utility Interconnection Application

This stage involves securing legal and technical permission from the electric utility to connect the microgrid to the public grid. It entails submitting detailed engineering packets for utility engineers to review, ensuring that the microgrid won't compromise the safety or stability of the broader distribution network.

INPUTS

Stamped engineering package

Inverter and equipment certifications

Interconnection application fees

ACTIONS

Submit formal interconnection request

Facilitate utility impact studies

Negotiate interconnection agreement

OUTPUTS

Signed interconnection agreement

Utility Queue Delays
COMMON PITFALL

ISSUE

Processing queues for microgrid interconnection permits, and even requisite studies beforehand (e.g., utility impact studies), are often underestimated

IMPACT

Project timeline slips by 6–12 months

MITIGATION STRATEGY

Submit the formal interconnection as soon as the preliminary microgrid SLD is ready

Plan Check

This stage ensures the microgrid complies with local building, fire, and zoning codes enforced by the Authority Having Jurisdiction (AHJ). It entails a multi-departmental review of site plans to ensure public safety, structural integrity, and environmental compliance.

INPUTS

Site plan and plot maps

Fire mitigation and BESS safety plan

Structural and civil calculations

ACTIONS

File building and electrical permits

Conduct environmental/ zoning review

Address plan check comments

OUTPUTS

Approved permit set

Regulatory & Permitting Requirements

Utility Interconnection
Typically requires the 30% or 60% SLD. The utility needs to know the "impact" on their grid (i.e., how much power is being pushed/ pulled), but they don't care how you route the local conduits.

Plan Check (Building/Electrical Department)
Generally, it requires the 90% or 100% set. Building inspectors must see every structural calculation and safety feature (e.g., fire suppression, setbacks, signage) before they issue a permit.

Fire Marshal Review
Requires 90%+, specifically focusing on battery chemistries, thermal management, and emergency shutdown procedures.

See **Table 4** for description of engineering design sets (e.g., 30%, 60%, 90%, 100%)

PHASE 4

CONSTRUCTION

In this phase, the project moves from paper to the physical site. This phase requires intense logistical coordination to ensure that long-lead equipment arrives on time and that the installation and construction adheres strictly to the engineered safety standards. This is typically the longest phase and involves the highest expenditure of capital.

Table 5 Example Procurement Triggers

Design Milestone	Procurement Action	Specific Components	Typical Lead Time
30%	Release Long-Lead POs	BESS, Main Power Transformer, Custom Medium-Voltage Switchgear.	40 – 60 Weeks
60%	Release Specialized POs	Inverters, Microgrid Controller Hardware, Protection Relays.	20 – 30 Weeks
90%	Release Commodity POs	PV Modules (if applicable), Racking Systems, RHW/THWN Wire, Steel Conduit.	4 – 12 Weeks
100% (IFC)	Release Consumables	Communication Cabling (Fiber/Cat6), Labeling/Signage, Commissioning Spare Parts.	1 – 2 Weeks

Procurement

This stage involves the strategic sourcing and delivery of all major microgrid components, such as batteries, inverters, and controllers. It entails managing vendor contracts and shipping timelines to ensure that high-cost, long-lead-time items arrive precisely when the site is ready for installation.

INPUTS

Bill of materials

Vendor lead-time schedule

ACTIONS

Purchase orders

Factory acceptance testing

“Just-in-time” delivery

OUTPUTS

Equipment delivery tracking log

Long-Lead Times
COMMON PITFALL

ISSUE

Ordering high-voltage switchgear, or other specialty components, too late in the process

IMPACT

Construction site sits idles for months waiting for the single component

MITIGATION STRATEGY

Identify long-lead items early in the Engineering phase and issue “Early Work” purchase orders prior to final design

Incompatible Firmware
COMMON PITFALL

ISSUE

Receiving components with different software versions that can’t “sync”

IMPACT

Massive delays during commissioning while waiting for remote software patches

MITIGATION STRATEGY

Specify exact firmware versions in the purchase order and require a Software Compatibility Certification from the vendor

Site Preparation

INPUTS

Civil and structural engineering plans

Geotechnical survey results

ACTIONS

Trenching and conduct replacement

Equipment foundations

OUTPUTS

Civil completion certificate

Electrical Installation & Mechanical Assembly

This stage is where the individual components are physically installed and wired together into a single system. It includes the high-precision work of pulling high-voltage cables and making the final terminations into the facility’s main electrical bus.

INPUTS

Approved electrical permit set

Health and safety plan

ACTIONS

Mount and secure equipment

Pull and terminate cables

OUTPUTS

As-builts construction markup

PHASE 5

COMMISSIONING

In this final phase, the focus shifts from physical construction to digital verification and regulatory finalization. This phase ensures the microgrid operates as a cohesive, intelligent system and legally transfers the asset from the developer to the owner. It is the bridge between a "completed project" and an "operational asset."



System Integration

This stage involves the systematic "power-on" sequence and functional verification of the software logic that controls the hardware. It entails a series of live tests to ensure the system reacts correctly to various energy demands and accurately executes the "Sequence of Operations."

INPUTS

Commissioning script and test plan

Final control logic code

ACTIONS

Black start testing

Communication link integrity test

OUTPUTS

Certified functional test report

Communication Gaps
COMMON PITFALL

ISSUE

Different equipment "languages" (e.g., Modbus vs. DNP3) not talking

IMPACT

The controller cannot see the battery or solar, preventing automation

MITIGATION STRATEGY

Require a "Communication Map" and pre-shipment bench testing of all digital links from vendors

Permission to Operate

This stage is the formal demonstration of the microgrid's safety and "anti-islanding" capabilities to the local utility provider (i.e., Utility Witness Testing). It entails a live demonstration where utility engineers verify that the system is safe to "parallel" with the public grid without risking the safety of grid workers.

INPUTS

Protection coordination report

Final as-built drawing set

ACTIONS

Utility awareness test

Final AHJ sign-off

OUTPUTS

Permission to operate letter

Owner Training Deficit
COMMON PITFALL

ISSUE

Handing over a complex microgrid system to staff without the knowledge to run it

IMPACT

Microgrid system is bypassed or decommissioned because it's deemed too complex

MITIGATION STRATEGY

Build a formal "Operator Certification" and support period (e.g., 3 months) into vendor contracts

Final Handover

This final task ensures the facility owner and their staff are appropriately trained and fully equipped to manage and maintain the microgrid over its multi-decade lifespan. It entails the transfer of all technical knowledge, warranty rights, and digital access from the project team to the end user.

INPUTS

Operations and maintenance manual

Emergency response plan

ACTIONS

Operator training sessions

Digital credentials and admin rights transferal

OUTPUTS

Final project closeout binder

SCHEDULE

MICROGRIDS

A microgrid project is not a linear process; several phases must overlap to avoid a stagnant site. The critical path sequence of stages that determines the minimum project duration almost always hinges on Utility Interconnection and Long-Lead Procurement.

Critical Path Management Tips

Front-Load the Permitting
Because the applicant has no control over utility or AHJ review times, these tasks should be treated as “pacing items.” If permit application can be submitted while still finalizing the 100% engineering details, weeks of dead time can be saved. Considering overlapping Permitting (Phase 3) and Engineering (Phase 2) as much as is permissible.

Procurement Buffers
Milestones 4 and 7 (Procurement) appear well before the Construction phase officially starts. In the microgrid industry, this is known as Equipment-Led Design. Because the physical dimensions and electrical characteristics of the battery (BESS) are fixed by the manufacturer once ordered, the 60% and 90% engineering designs must be finished around the specific equipment you purchased at the 30% stage.

“Dead Zone” Prevention
The most dangerous gap in this timeline occurs between Milestone 11 (Integration) and Milestone 12 (PTO). Many owners assume that once the hardware is installed, they are finished. However, if the Controls & Communications Design (from Phase 2) did not account for the utility’s specific cybersecurity or relay settings, the utility can refuse to grant PTO, leaving you with millions of dollars in equipment that you are legally forbidden from turning on.

Table 6 Critical Path Milestones

	Milestone	Phase	Why it is Critical Path
1	**Determination of Purpose** Establish the specific use case, sizing requirements, and financial goals for the system.	1	Incorrect sizing here ripples through every subsequent engineering and procurement decision.
2	**30% Design (Conceptual)** Create the initial site layout and Single Line Diagram (SLD) for stakeholder review.	2	This set is the minimum requirement to enter the utility interconnection queue.
3	**Interconnection App** Submit formal technical documents to the utility to request grid parallel operation.	3	This is the longest lead-time regulatory item; the project cannot energize without it.
4	**Long-Lead Procurement** Execute purchase orders for major hardware like BESS and main transformers.	4	Factory lead times (40+ weeks) often exceed the total duration of design and construction combined.
5	**60% Design (Detailed)** Refine electrical calcs and structural plans to a level sufficient for building permits.	2	Necessary to "lock" the civil design so site preparation can legally begin.
6	**Plan Check Submission** Submit the permit package to the local AHJ (Building/Fire Dept) for safety review.	3	Construction cannot break ground until the local building department issues the permit.
7	**Specialized Procurement** Order the microgrid controller, inverters, and specialized protection relays.	4	These items must arrive just as the civil work finishes to avoid site stagnation.
8	**90% / 100% Design (IFC)** Produce the “Issued for Construction” set that incorporates all permit and utility comments.	2	Provides the final, legally binding blueprint for the contractor's physical installation.
9	**Site Preparation** Perform grading, trenching, and concrete pad pouring for equipment placement.	4	Hardware cannot be delivered or bolted down until foundations are cured and inspected.
10	**Assembly & Installation** Physically mount the hardware and perform the final high-voltage electrical terminations.	4	This is the most labor-intensive portion and must be finished before software testing begins.
11	**System Integration** Configure the IT/OT network, program control logic, and verify cybersecurity protocols.	5	The "brain" of the system must be fully functional for the system to operate autonomously.
12	**Witness Testing / PTO** Final utility inspection to prove safety compliance and receive Permission to Operate.	5	The project is not legally allowed to function or generate value until this final sign-off.

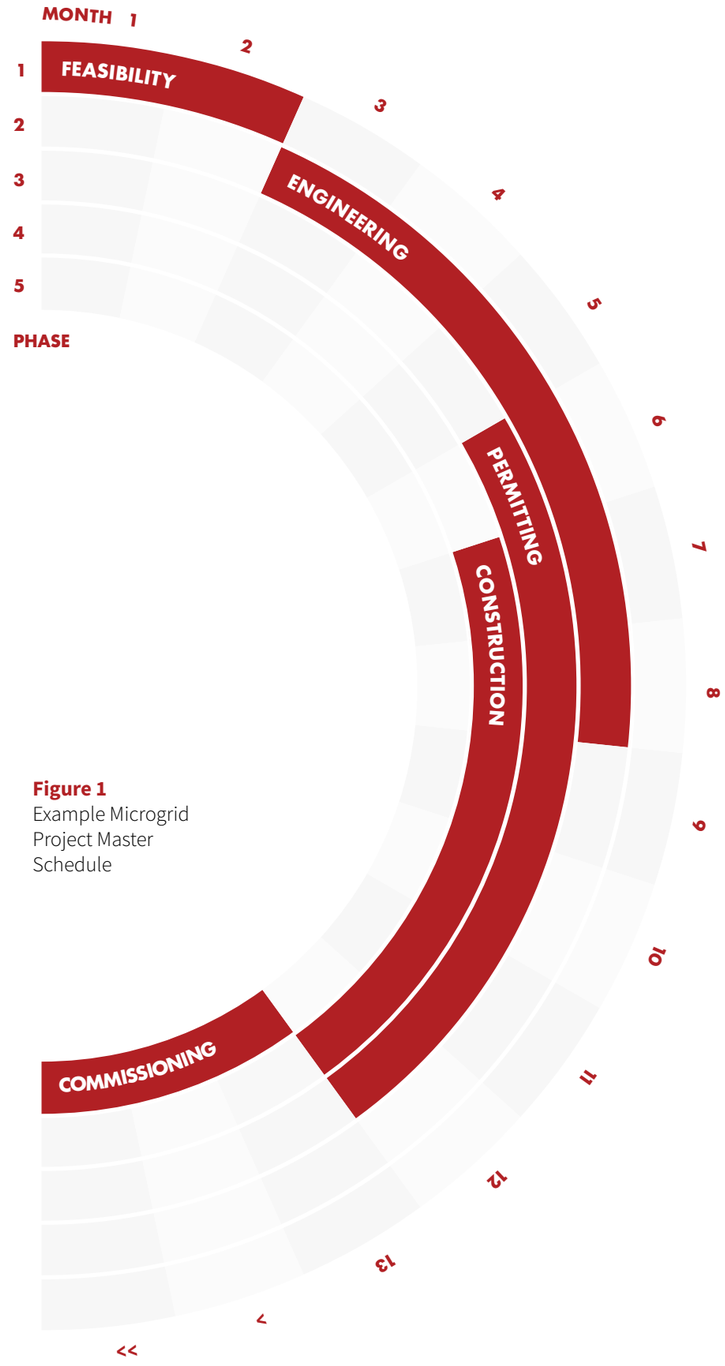


Figure 1
Example Microgrid Project Master Schedule

VENDORS

MICROGRIDS

The following resources provide a structured framework for identifying, selecting, and managing the various specialized entities required to move a microgrid project from concept to energized operation. These tables clarify the distinct "lanes" of expertise for consultants and contractors, helping an owner assign accountability and avoid the management gaps that often lead to technical delays.

Understanding the "EPC" Model

For many microgrid projects, owners hire an Engineering, Procurement, and Construction (EPC) contractor. This single firm acts as the prime contractor for Phases 2 through 5, reducing the "finger-pointing" risk between the designer and the installer and serving as a lead contractor for the microgrid owner.

Types & Capabilities

The table below defines the core identity of each primary project partner and establishes the boundaries of where their expertise begins and ends.

Table 7 Microgrid Vendor Roles & Capabilities

Role	What They Can Do	What They Cannot (or Should Not) Do
Consultant Specialized advisory firm or Professional Engineer (PE) that provides technical expertise and modeling without providing physical labor 1 2 3 4 5	Perform feasibility studies, economic modeling, and 30%/60% engineering designs	They do not typically purchase equipment or perform physical electrical installation
EPC Contractor "Engineering, Procurement, and Construction" firm that provides a turnkey, single-point-of-contact solution for the entire project 1 2 3 4 5	They handle everything from detailed design and buying batteries to physical building and commissioning	While they can consult, they may have a bias toward specific hardware brands they sell
General Contractor (GC) Construction manager who oversees site labor and civil works but often subcontracts specialized electrical work 1 2 3 4 5	Manage site safety, pour concrete pads, dig trenches, and coordinate various sub-contractors	They rarely have the specialized software or engineering staff to model microgrids or perform integration

Selection Considerations

Design Logic (Phases 1 & 2)
While an EPC can perform Feasibility and Engineering, hiring a Consultant first ensures a "Vendor Neutral" design. This prevents the project from being designed around a specific battery brand that the EPC might prefer to sell.

Execution Logic (Phase 4)
The General Contractor (GC) is typically limited to Site Preparation (civil works). They lack the specialized electrical licenses or software expertise to handle high-voltage Procurement or Mechanical Assembly of microgrid assets.

Verification Logic (Phase 5)
It is common practice to have a Consultant (acting as a "Commissioning Agent") oversee the EPC during System Integration to ensure the physical build matches the original economic promises.

Roles

The table below provides an introduction to which type of firm is qualified to execute specific tasks, noting where roles may overlap depending on your chosen delivery method.

Table 8 Microgrid Partner Selection Guide

Stage	Consultant	EPC Contractor	GC
Phase 1 Feasibility			
Determination of Purpose	●*	○	○
Load Profiling	●	●	○
Resource Assessment	●	●	○
Economic Modeling	●	●	○
Phase 2 Engineering			
System Modeling	●	●	○
Electrical Design	●	●	○
Controls & Comm. Design	●	●	○
Phase 3 Permitting			
Utility Interconnection	●	●	○
Plan Check	●	●	○
Phase 4 Construction			
Procurement	○	●	○
Site Preparation	○	●	●
Elec. & Mech. Assembly	○	●	○
Phase 5 Commissioning			
System Integration	●	●	○
Permission to Operate	●	●	○
Final Handover	●	●	●

*Optional

Table 9 Microgrid Project RACI Matrix

The table below outlines a typical hierarchy of responsibility and accountability in a microgrid project, such that the owner, technical partners, and regulators are aligned at every milestone.

Stage	Owner	Consultant	EPC Contractor	GC	Utility	AHJ
Phase 1 Feasibility						
Determination of Purpose	A | R	C	I	I	I	I
Load Profiling	A	R	I	I	C	I
Resource Assessment	A	R	I	I	I	I
Economic Modeling	A	R	C	I	I	I
Phase 2 Engineering						
System Modeling	I	C	A | R	I	I	I
Electrical Design	I	C	A | R	I	C	I
Controls & Comm. Design	I	A	R	I	I	I
Phase 3 Permitting						
Utility Interconnection	A	C	R	I	R	I
Plan Check	C	I	R	I	I	A
Phase 4 Construction						
Procurement	A	I	R	I	I	I
Site Preparation	I	I	A	R	I	I
Elec. & Mech. Assembly	I	I	A | R	C	I	I
Phase 5 Commissioning						
System Integration	C	A	R	I	I	I
Permission to Operate	C	C	R	I	A | R	I
Final Handover	A | R	I	R	I	I	I

A Accountable
The party who "owns" the result and must sign off on it

R Responsible
The party who performs the work

C Consulted
Those whose opinions are sought (two-way communication)

I Informed
Those kept up-to-date on progress (one-way communication)

Key Role Distinctions

Consultant v EPC

Consultant vs. EPC in Commissioning
Notice that the Consultant is often Accountable (A) for System Integration. This is because they designed the original economic model and must verify that the EPC's software actually achieves the promised performance.

EPC v GC

EPC vs. GC
The EPC is Accountable (A) for the entire build, but the General Contractor is Responsible (R) for the physical Site Preparation (digging trenches, pouring pads). The GC "reports" to the EPC's master schedule.

Utility AHJ

Utility/AHJ as Gatekeepers
These roles are Accountable (A) for their specific stages (Interconnection and Plan Check). Work cannot proceed to the next phase without their formal "A" sign-off.

Which Vendor Path to Choose?

1. **"Turnkey" Path**
   Owner hires one EPC Contractor for Phases 2–5. This is the simplest management structure and reduces "finger-pointing" if the system doesn't work.
2. **"Owner's Rep" Path**
   Owner hires a Consultant for Phase 1 and to provide oversight during Phases 2–5. This ensures someone is looking out for the owner's interests and verifying the EPC's work.
3. **"Split-Prime" Path**
   Owner hires a Consultant for Design and a separate GC/Electrical Contractor for Construction. This is often the lowest-cost path but carries the highest risk if the design and construction teams don't communicate well.

"Critical Handover" Point: The most complex transition occurs between Phase 4 and Phase 5.

The General Contractor usually finishes their work and leaves the site, while the EPC and Consultant remain to perform the "digital" work of system integration. Ensuring the GC's physical work, such as conduit placement, is 100% accurate is vital, as fixing a physical error during the digital commissioning phase is extremely expensive.

CONTRACTING MODELS

In the context of the microgrid lifecycle, choosing between **Design-Build** and **Design-Bid-Build** contracting models is a decision about how the owner wants to manage risk, cost, and the "hand-off" between vendors. Tables 10 and 11 present consideration factors for selecting between these delivery methods.

Table 10 Contracting Models

Contracting Model	Pros	Cons
Design-Build Owner hires one entity (typically an EPC) to handle everything from the initial engineering to the final commissioning. There is a single contract and a single point of responsibility.	**Single Point of Responsibility** If the system doesn't "island" correctly, the EPC cannot blame the designer because they are the designer. **Faster Execution** Construction can begin while final design details are still being polished (Fast-tracking). **Cost Certainty** Usually results in a "Guaranteed Maximum Price" early in the process.	**Less Owner Control** You have less oversight over specific component brands or "gold-plated" engineering choices. **Potential for Conflict of Interest** The firm might design the system around the specific equipment they have in stock or have the highest margins on. **Harder to Compare Bids** Since each EPC proposes their own design, you aren't comparing "apples to apples" on price.
Design-Bid-Build Owner hires a Consultant to fully design the system first. Once the design is 100% complete, the owner then puts that design out to tender ("bid") and hires a separate General Contractor or Electrical Contractor to build it.	**Owner Advocacy** Your Consultant works only for you and ensures the design is optimized for your needs, not a contractor's profit. **Competitive Pricing** Because every contractor is bidding on the exact same set of blueprints, you can select the lowest responsive bidder. **High Transparency** The owner sees every detail of the design before a single dollar is spent on hardware.	**"Finger-Pointing" Risk** If the system fails during commissioning, the contractor may blame the design, while the designer blames the installation. **Longer Timelines** You cannot start construction until the design is 100% finished and the bidding process is complete. **Change Order Risk** Any error in the consultant's design results in a "Change Order" from the contractor, which can inflate the budget.

Because microgrids are software-intensive assets, the Design-Build (EPC) model is most common.

In a Design-Bid-Build scenario, the high risk of a communication gap between the "Controls Design" (Phase 2) and "System Integration" (Phase 5) often leads to significant delays that negate any initial savings found during the bidding process.

Table 11 Microgrid Delivery Method Matrix

Selection Factor	Consider Design-Build (EPC) if...	Consider Design-Bid-Build if...
Technical Complexity	The system has complex software/islanding requirements.	The system is a standard "grid-tied" solar array without complex controls.
Risk Tolerance	Want a "single point of responsibility" for system performance.	Comfortable managing disputes between designers and installers.
Schedule Pressure	Need to fast-track the project and order equipment early.	Have a flexible timeline and can wait for 100% design completion.
Internal Expertise	Have a small team and need a "turnkey" partner.	Have an in-house engineering team to oversee a consultant's work.
Procurement Rules	Organization allows "Value-Based" selection.	Organization requires selecting the "Lowest Responsive Bidder."

Strategic Summary

Design-Build
"Efficient" Method
In this model, the aim is a more predictable outcome. The owner tells the EPC, "I need 500kW of resilience for 4 hours," and they are responsible for the engineering, the batteries, and the software to make it happen.

Common with: Commercial and Industrial customers, hospitals, and data centers.

Design-Bid-Build
"Transparency" Method
In this model, the owner is buying professional services first, then labor and materials second. It allows you to have a Consultant "check the math" of the Contractor, but it places the burden of project management back on the owner's shoulders.

Common with: Municipalities, schools, and government agencies with strict public bidding laws.

Hybrid Approach
"Owner's Engineer"
Many successful microgrid owners use a hybrid approach: they hire a Consultant to act as an Owner's Engineer. This consultant performs the Feasibility (Phase 1) and Preliminary Engineering (Phase 2), then helps the owner select a Design-Build EPC and monitors their work through completion. This gives you the single-point responsibility of an EPC with the expert advocacy of a Consultant.

COMMUNITY RESILIENCE CENTERS

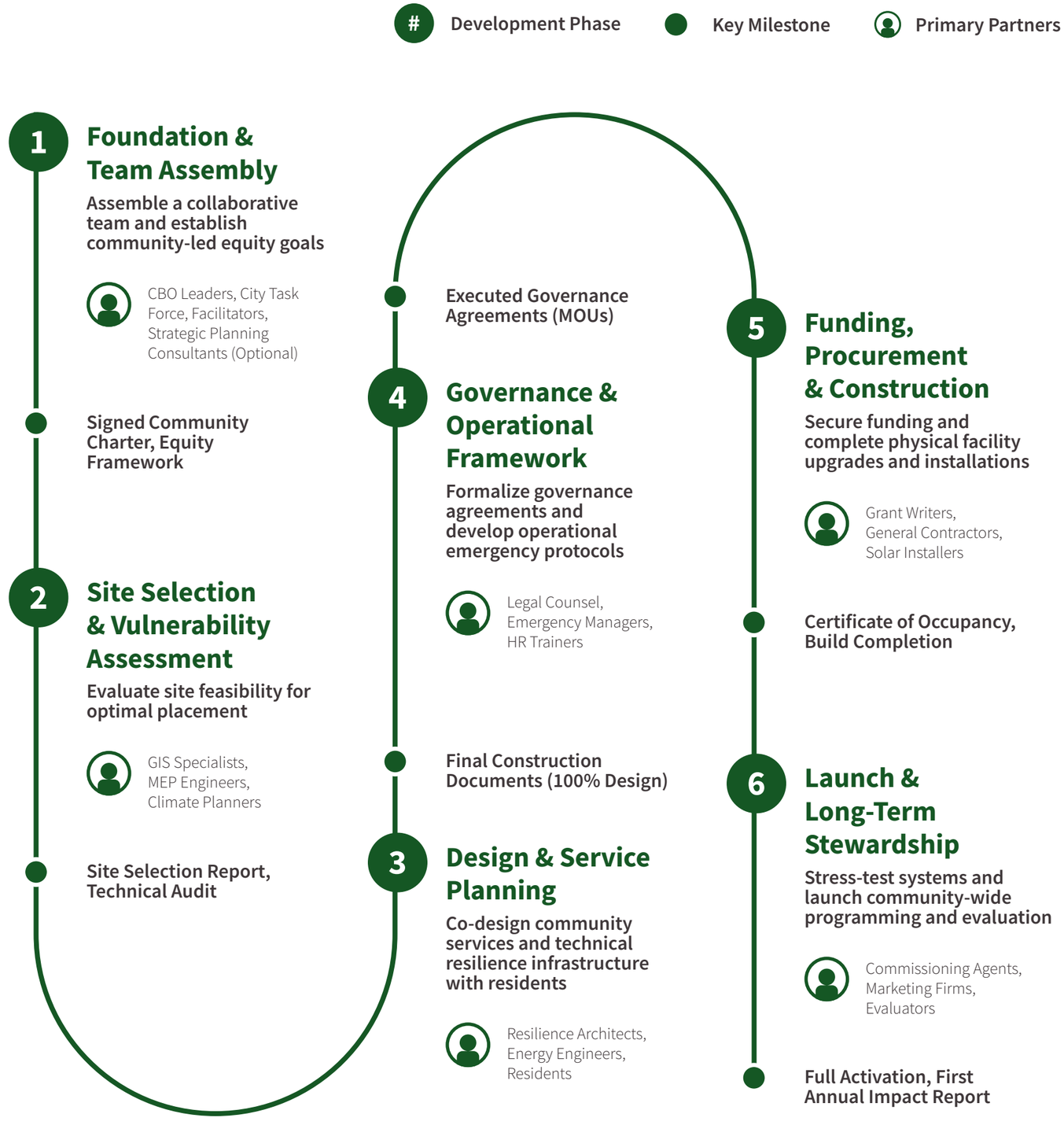
IMPLEMENTATION PLAN

Establishing a Community Resilience Center (CRC) can transform a static building into a dynamic social and resource hub for residents. Because the CRC model is a relatively new evolution in urban planning, this guide moves beyond traditional emergency management to focus on creating a facility that is as valuable on an ordinary weekday as it is during a grid-down emergency.

The following pages detail the prototypical phases of CRC development. Each phase is broken down into specific stages for guidance from initial visioning to final commissioning.

The graphic on the right summarizes the progression from initial visioning to a fully operational CRC. It integrates the technical requirements of the SGC Guidelines with the community-power-building focus of the USDN framework.

This roadmap is based on the California Strategic Growth Council (SGC) and Urban Sustainability Directors Network (USDN) frameworks.



WHO IS THIS FOR?

This guidance is designed for city leaders, sustainability offices, and public works departments who are just beginning to evaluate how existing or new city-owned facilities can be converted into CRCs. It is a roadmap for the cross-departmental coordination required to bridge the gap between "hard" infrastructure (solar, HVAC, seismic) and "soft" social infrastructure (community trust, governance, and programming).

HOW TO USE THIS GUIDE

This guide functions as both a strategic sequence and a functional checklist. While the phases generally follow a linear path, many tasks can and should run in parallel.

Essential
Stages involving community governance (Phase 1) and technical "islanding" capabilities (Phase 3) are non-negotiable for a true resilience hub.

Optional
Specific programmatic elements in Phase 3 (like community gardens or tool libraries) are flexible and should be dictated by local needs.

While this plan represents an approach pathway, it is not intended as "one-size-fits-all." It is encouraged to integrate this guidance into existing municipal programming. For instance, if there is an existing Capital Improvement Plan, an active Community Outreach department, or an updated Hazard Mitigation Plan, the following presented stages can, and should, be aligned with those ongoing efforts.

The prospective CRC developer is referred to as "City" hereafter, given WRCOG's intent to provide this resource for its member agencies, who are predominantly cities.

PHASE 1

FOUNDATION & TEAM ASSEMBLY

Phase 1 begins with building the organizational foundation and neighborhood partnerships necessary to sustain a resilience center over the long term. This stage aligns city departments and sets clear objectives to ensure the project remains focused on serving the most immediate local needs.

Internal City Coordination

A first step can be assembling a small team from departments like Public Works, Sustainability, and Emergency Management to ensure the project covers both technical and safety needs. This group can identify how a resilience center aligns with existing city goals and what municipal resources might already be available to support the transition. Coordination at this early stage helps prevent silos and simplifies the planning process as the project moves forward.

Exploring Community Input (Optional)

While not a requirement, forming a Community Advisory Committee (CAC) can provide valuable local insight to ensure the facility meets actual resident needs. If a formal committee isn't feasible given current resources, cities can still gather helpful feedback through informal chats with neighborhood leaders or by attending existing community meetings. The goal is simply to ensure the center's services are useful and trusted by the people who will rely on them most.

Defining a Shared Vision

Setting a clear, simple vision early on (e.g., providing reliable power during outages or a clean-air respite during wildfires) helps guide the project through later technical decisions. These objectives don't need to be complex. They can simply reflect the most immediate resilience needs of the neighborhood. Having a documented collective objectives can make it much easier to communicate the project's value to stakeholders and potential funding partners.

Example CRC Objectives

Climate & Health Respite
Establish a safe, indoor environment equipped with high-efficiency air filtration and cooling to protect vulnerable populations during extreme heat or wildfire smoke events.

Energy & Communication Reliability
Provide a dependable location for residents to charge essential medical devices and cellular phones during localized power outages or grid failures.

Daily Resource Accessibility
Maintain a trusted neighborhood hub that offers year-round access to high-speed internet, clean water, and community-led social programming.

Food and Water Security
Serve as a neighborhood distribution point for shelf-stable food and potable water during supply chain disruptions, ensuring residents have access to basic nutrition when local grocery stores are inaccessible.

Considerations

Start Small
A city does not need to solve every climate risk at once. Selecting just one primary objective—such as "extreme heat relief"—allows for a more focused and affordable Phase 2 assessment, as the engineering requirements for cooling are often less complex than those for a full-scale emergency medical shelter.

Don't Start from Scratch
Your city is likely already doing some of this work; a CRC is often just a way to "package" existing services more effectively

Parallel Paths
Feel free to jump to Phase 2 (checking out your buildings) while you're still doing these Phase 1 meet-and-greets

PHASE 2

SITE SELECTION & VULNERABILITY ASSESSMENT

Phase 2 focuses on gathering the necessary data to ensure the resilience center is located in the right place and equipped with the right technology. This stage uses existing information to match neighborhood needs with a building's physical capacity.

Climate Risk Mapping

This analysis can be conducted in-house or with a contractor. In either case, planners can use localized data to identify the primary environmental threats to the neighborhood, such as extreme heat, wildfire smoke, or flood zones. This assessment determines the specific technical requirements for the facility, such as the need for advanced air filtration or floodproofing. Conducting this risk mapping ensures the CRC is located in an area where it can provide the most significant life-safety benefits.

U.S. Climate Vulnerability Index

Data-driven mapping tool developed by the Environmental Defense Fund and Texas A&M that ranks over 70,000 census tracts to visualize where compounding socioeconomic, infrastructure, and environmental factors make communities most susceptible to climate change risks.

map.climatevulnerabilityindex.org

Social Vulnerability Indexing

Similarly, this analysis can be conducted in-house or with a contractor. Reviewing social data helps pinpoint neighborhoods with the highest concentration of residents who may be disproportionately affected by climate events. This process identifies priority areas where a resilience hub can provide the greatest benefit to residents with limited resources, medical dependencies, or mobility challenges. Integrating these social metrics ensures the project is situated where it can most effectively improve community safety and equity.

Example Resources

CalEnviroScreen
CalEnviroScreen is a science-based mapping and screening tool developed by the California Office of Environmental Health Hazard Assessment that identifies communities disproportionately burdened by sources of pollution.

Vulnerable Communities Platform
The Governor's Office of Land Use and Climate Innovation's Vulnerable Communities Platform is an interactive, web-based tool designed to map California communities most vulnerable to climate hazards, such as wildfire and flooding, by combining social, economic, and environmental data to help target adaptation resources and build local resilience.

Site Feasibility Study

An evaluation of existing municipal buildings, such as libraries or community centers, determines which locations are most viable for a resilience retrofit. This study assesses structural readiness, available roof space for solar panels, and the condition of electrical systems to provide a realistic picture of potential costs. Verifying site control and long-term ownership early in the process ensures the facility meets the necessary legal requirements for state and federal grant eligibility.

Site feasibility for a CRC, as outlined by guidance from sources like the Urban Sustainability Directors Network, depends heavily on **community support** and a **trusted, existing physical location** that can be augmented with resilient infrastructure.

Considerations

Use Free Tools
Instead of hiring a specialized firm for mapping, utilize free resources like CalEnviroScreen

Leverage Existing Audits
Check for recent energy audits or ADA compliance reports already performed on city buildings to save on technical assessment costs

Prioritize Accessibility
If a full engineering study isn't possible yet, start with a simple walk-through to check for basic needs like proximity to transit and ground-floor access

Site Feasibility Key criteria

Community and Location

- **Community Trust & Support**
  The most important factor is strong desire and support from the community, ensuring local leaders and organizations are involved in site selection and management from the beginning.
- **Accessibility**
  The site must be centrally located and easily accessible to all community members, including vulnerable populations, via walking, biking, and public transit routes. It should also be near major roads for emergency access.
- **Existing Facility**
  Utilizing an existing, well-used community facility (e.g., community centers, libraries, places of worship, schools) is preferred to build on existing trust and infrastructure.

Building and Infrastructure

- **Physical Condition**
  The building should be in good condition, structurally sound, and ideally outside of a floodplain. Federal Emergency Management Agency (FEMA) provides checklists to assess hazard vulnerability.
- **Resilient Power Systems**
  The facility must be able to sustain operations during an extended power outage using reliable onsite power systems.
- **Essential Services**
  The hub must be equipped to provide essential services during a disruption, including heating/cooling, clean water storage and filtration, refrigeration for medicine, and communication systems.
- **Resilient Design Features**
  The site should incorporate features such as flood protection, passive survivability (natural ventilation and shading), and rainwater management.
- **Accessibility and Inclusivity**
  The site must comply with ADA accessibility standards and offer culturally responsive services like language access to accommodate the diverse needs of the population it serves.

Operations and Programming

- **Year-Round Use**
  The hub should function as a vital community center year-round for non-emergency activities such as job training, health services, and educational programs, not just sit dormant until a disaster.
- **Resource Stockpile**
  There needs to be sufficient storage for emergency supplies like food, water, basic medical supplies, and first aid kits.
- **Partnerships**
  Strong partnerships with local government agencies, non-profits, and private entities are crucial for support, logistics, and ongoing operations.

PHASE 3

DESIGN & SERVICE PLANNING

Phase 3 translates the vision and data gathered in previous phases into a functional design for both the facility and its programs. This phase ensures that the physical building and the services provided inside it work together to support residents during both daily operations and crisis events.



Social Vulnerability Indexing

Collaborative sessions can be held to gather resident input on the layout and desired amenities of the center. This process helps prioritize features (e.g., community kitchens, laundry facilities, or device charging stations) that reflect actual neighborhood preferences. Engaging residents during the design phase builds a sense of ownership and ensures the facility is perceived as a welcoming, useful resource.

Technical Infrastructure Design

This stage can be conducted in-house or with a contractor. Technical design here integrates specialized resilience infrastructure, such as solar energy with battery storage and advanced air filtration systems. Engineers focus on creating “islandable” power systems that allow the building to remain functional if the main utility grid fails. The design also incorporates upgrades to HVAC (e.g., MERV 13+) and plumbing to maintain a safe environment during extreme heat, wildfire smoke, or water shortages.

Defining Modes of Operation

Developing a plan for different “modes” of operation ensures the center remains a neighborhood asset 365 days a year. “Blue Skies” mode focuses on daily social services, while “Gray Skies” and “Black Skies” modes outline how the facility shifts to provide emergency respite and long-term recovery support. Defining these transitions clearly helps staff and partners understand exactly how space and resources will adapt as local needs change.

Considerations

Start Small
If a full microgrid is too expensive, design the electrical system to be “solar-ready” so panels and batteries can be added in stages as funding becomes available.

Don’t Start from Scratch
Rather than hosting standalone design workshops, set up a booth at a local farmers’ market or school event to gather community feedback with minimal overhead

Parallel Paths
For air quality, consider high-quality portable HEPA air purifiers for specific rooms if a full building HVAC overhaul is currently out of reach

Engaging residents during the design phase builds a sense of ownership and ensures the facility is perceived as a welcoming, useful resource.

PHASE 4

GOVERNANCE & OPERATIONAL FRAMEWORK

Phase 4 focuses on the organizational rules of the road, establishing clear agreements and procedures so that all parties knows how the facility should operate. This phase builds the management framework needed to handle the transition from a daily community space to an emergency respite center.

Phases 3 and 4 can be conducted concurrently.

Developing design and governance concurrently ensures the physical space is engineered to support the specific operational protocols, partnership agreements, and emergency management roles defined by the team.

Governance Agreements

Formalizing relationships through Memorandums of Understanding (MOUs) provides a clear framework for how the City and community partners will share the space. These agreements outline responsibilities such as insurance, liability, and decision-making authority during different modes of operation. Establishing these protocols early prevents confusion and ensures a seamless transition when emergency services are required.

Operations & Maintenance Manual

A standard operating manual acts as the technical playbook for the facility, detailing how to activate resilience features like the microgrid or emergency water systems. This document identifies specific triggers (e.g., heat advisory or a power outage) that prompt the facility to move from daily use into a disruption response mode. Keeping this manual updated ensures that facility managers can operate the building's complex systems effectively under pressure.

Staffing & Training Plan

Identifying the right mix of city staff and community volunteers is essential for maintaining a safe and welcoming environment. Training programs for these individuals can cover basic emergency response, de-escalation techniques, and trauma-informed care to better support residents during stressful events. A well-defined staffing plan ensures the center is appropriately supervised without overextending any single department's budget or personnel.

Considerations

Use Templates
Instead of drafting MOUs from scratch, the team can adapt existing templates from organizations like the USDN or use mutual aid agreements already in place between city departments

Cross-Train Existing Staff
Rather than hiring new personnel, the City can provide resilience training to current library or park staff who already manage the facility

Digital Playbooks
Create a simple, shared digital folder for the O&M manual that is accessible via mobile devices, ensuring staff can access instructions even if they are away from their desks during an incident







PHASE 5

FUNDING, PROCUREMENT, & CONSTRUCTION

Phase 5 moves the project into the physical implementation stage, focusing on securing the necessary capital and completing the actual construction or retrofitting. This phase turns the engineering plans and community visions into a tangible, resilient building.

Secure Capital & Programmatic Funding

Budgeting for a CRC involves seeking a mix of funding sources to cover both the physical construction and the ongoing social programming. The City can align grant applications with state programs like the SGC's CRC grants. Securing a blend of capital and operational funds ensures the building remains a functional asset long after the initial construction is complete.

Procurement & Bidding

Consider selecting contractors who have the specialized skills required for microgrid installation and high-efficiency HVAC retrofits. Procurement policies can be designed to prioritize local businesses or firms that provide fair wages, which helps the project contribute to the neighborhood's economic resilience.

Retrofitting & Construction

During the construction phase, the facility undergoes the physical upgrades needed to meet its new resilience standards. This may include installing solar panels, seismic bracing, high-efficiency HVAC, and/or improved insulation to ensure the building remains habitable during extreme weather.

Considerations

Piggyback on Other Projects
If the City is already planning a roof replacement or an HVAC upgrade for a building, the resilience components can be added to that existing project to save on mobilization costs

Rebate Programs
Look for utility-sponsored rebates for solar, battery storage, or energy-efficient appliances to offset the hard costs of the equipment

Phased Construction
If full funding isn't available at once, the project can be broken into phases, such as starting with the HVAC upgrades and adding the solar microgrid in a later budget cycle



Although presented here in Phase 5, it is recommended that availability and viability of funding sources is reviewed and discussed with decisionmakers and key stakeholders early in the CRC development process.

PHASE 6

LAUNCH & LONG-TERM STEWARDSHIP

Phase 6 is the final step, involving the rigorous testing of all systems and the official launch of the CRC's services. This phase ensures the facility is truly ready to perform and creates a cycle of continuous improvement based on real-world use.

Secure Capital & Programmatic Funding

Before the facility is opened for emergency use, an independent agent should verify that all technical systems function exactly as designed. "Black-start" tests are conducted to ensure the microgrid can power the building's essential loads without any assistance from the utility grid. This rigorous testing phase identifies any mechanical issues before a real disaster occurs, providing peace of mind to staff and residents.

Procurement & Bidding

A grand opening or community open house can serve as the official introduction of the center to the neighborhood. Multilingual outreach materials and neighborhood tours help residents understand what services are available and how to access the building during different types of emergencies. Effective communication ensures that when a crisis hits, the community already knows the center is a safe and reliable destination. This stage is about shifting the facility from a "project" to a recognized neighborhood "resilience center."

Retrofitting & Construction

The final stage establishes a process for tracking the center's performance and gathering feedback from the people who use it. Regular reviews of energy performance and community satisfaction allow the City to make data-driven adjustments to programming and operations. This ongoing stewardship ensures the center remains a relevant and trusted resource as climate risks and neighborhood demographics evolve over time.

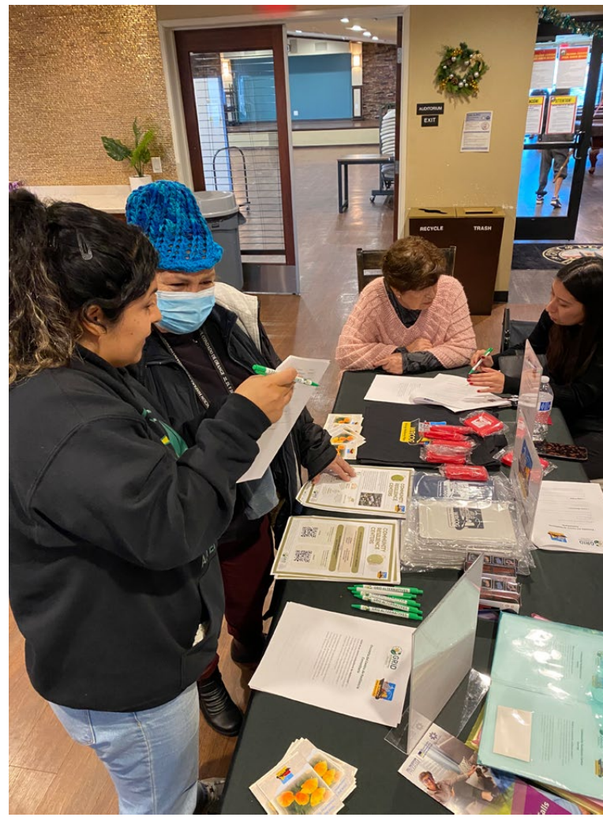
Considerations

Community Drills
Instead of expensive formal testing, host a "resilience day" where residents practice coming to the center, which serves as both a system test and a public awareness event

Student Interns
Partner with a local university or high school to have students help with data collection and resident surveys as part of a service-learning project

Social Media Outreach
Use the City's existing social media channels and neighborhood apps like Nextdoor to spread the word about the center's "Blue Sky" programs and "Gray Sky" emergency functions at no cost

Multilingual outreach materials and neighborhood tours help residents understand what services are available and how to access the building during different types of emergencies.



SCHEDULE

COMMUNITY RESILIENCE CENTERS

Establishing a Community Resilience Center is a multi-year commitment. Based on the SGC Round 2 Guidelines, which typically allow for a 5-year implementation grant term, and the USDN framework, the total process generally spans 3 to 5 years from initial visioning to the grand opening.

Primary Focus

Milestone

Concurrent

DISCLAIMER

Actual project duration is highly dependent on utility interconnection timelines and study queues, which may extend beyond planning assumptions and are outside the control of the project sponsor.

Site Selection & Vulnerability Assessment

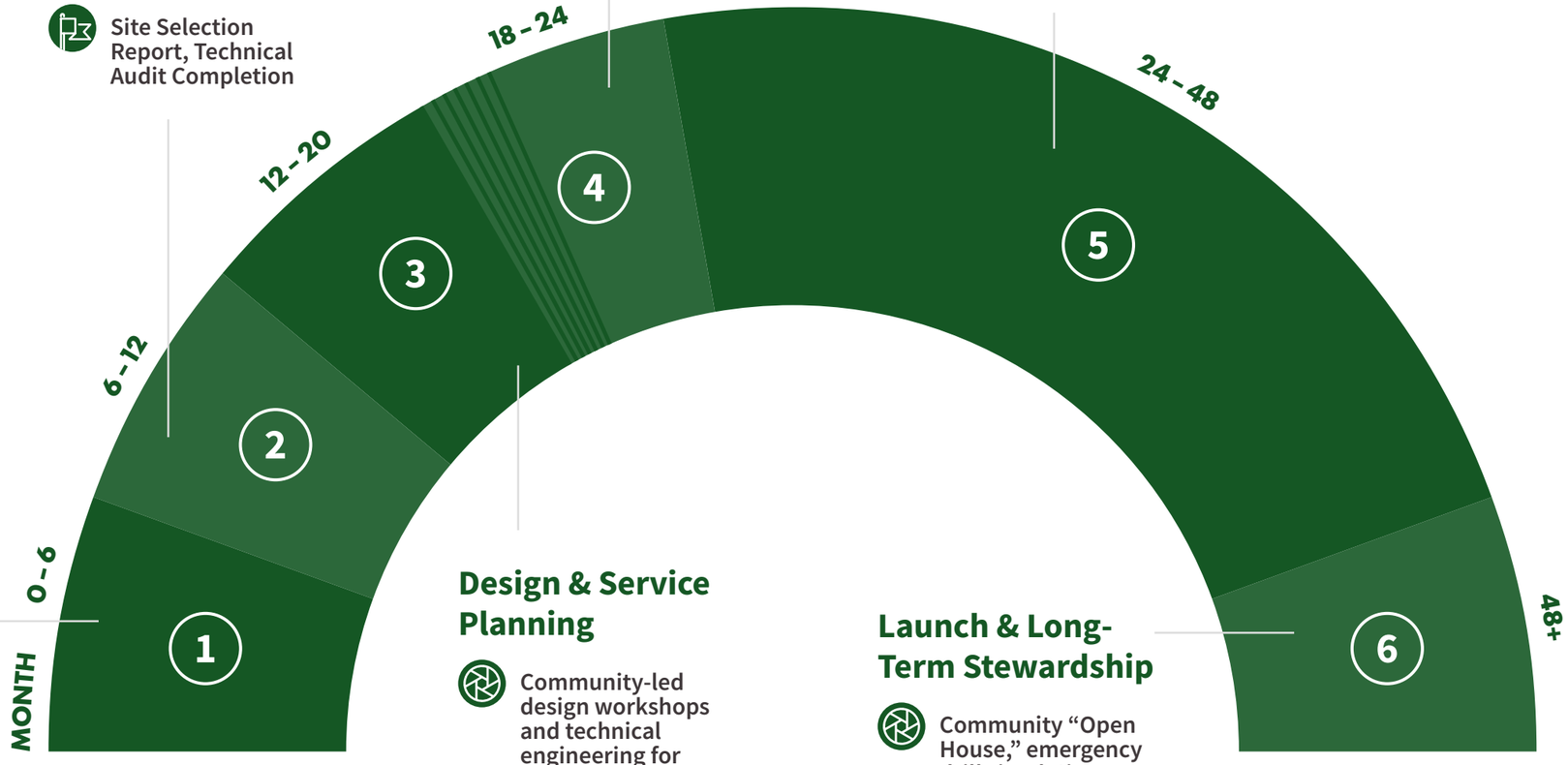
- Climate risk mapping, social vulnerability indexing, and engineering site feasibility studies
- Site Selection Report, Technical Audit Completion

Governance & Operational Framework

- (Concurrent with Phase 3) Drafting MOUs, legal agreements, and operational “playbooks”
- Executed MOUs between City and Partners

Funding, Procurement, & Construction

- Procurement/Bidding, physical retrofitting, microgrid installation, and staff training
- Certificate of Occupancy, System Commissioning



Foundation & Team Assembly

- Relationship building, internal alignment
- Community Charter, Equity Framework

Design & Service Planning

- Community-led design workshops and technical engineering for microgrids and HVAC
- **Final Construction Documents** & Design Approval

Launch & Long-Term Stewardship

- Community “Open House,” emergency drill simulations, and ongoing program evaluation
- Full Activation, First Annual Impact Report

VENDORS

COMMUNITY RESILIENCE CENTERS

To move from planning to reality, the City may need to engage a diverse range of technical and social experts. Below is a breakdown of the vendors, ranging from specialized consultants to technical contractors, that may be required at each stage of the process.

● Required

○ Optional

Vendor Considerations

Integrated Project Delivery
For Phases 3 and 5, the City may prefer a "Design-Build" firm that specializes in resilience, as this ensures the energy engineers and architects work together on the CRC from day one.

SGC Compliance
Ensure that construction vendors (Phase 5) have experience with prevailing wage requirements and targeted hire programs, as these are often mandatory for California Strategic Growth Council funding.

Third-Party Commissioning
For Phase 6, it may be prudent to hire an independent Commissioning Agent (CxA) who was not part of the construction team to verify that the energy and air filtration systems perform exactly as designed during a crisis.

Table 12 Community Resilience Center Vendor Roles

Stage		Vendor Type	Key Services Provided	Status
Phase 1	**Foundation & Team Assembly**			
1.1	Internal Alignment	Strategic Facilitator	Guiding departmental workshops and aligning goals	○
1.2	Community Input	Engagement Specialist	Managing neighborhood outreach and advisory groups	○
1.3	Shared Vision	Planning Consultant	Drafting the vision statement and project framework	○
Phase 2	**Site Selection & Vulnerability Assessment**			
2.1	Climate Risk	Environmental Mapping Firm	Providing localized data on heat and flood risks	○
2.2	Social Data	Data Analyst	Identifying vulnerable populations and priority zones	○
2.3	Feasibility	Structural and Electrical Engineers	Assessing building integrity and power capacity	●
Phase 3	**Design & Service Planning**			
3.1	Workshops	Design Facilitator	Leading community co-design sessions for the space	○
3.2	Infrastructure	Resilience Architects and Engineers	Designing microgrids and high-efficiency air systems	●
3.3	Operating Modes	Operations Specialist	Planning for daily versus emergency use of space	●
Phase 4	**Governance & Operational Framework**			
4.1	Agreements	Legal Counsel	Drafting shared use and liability agreements	●
4.2	Manuals	Emergency Management Consultant	Creating standard operating procedures and triggers	●
4.3	Training	Safety and Wellness Trainers	Providing trauma-informed care and response training	●
Phase 5	**Funding, Procurement, & Construction**			
5.1	Funding	Grant Writing Specialist	Identifying and applying for state or federal funds	○
5.2	Procurement	Procurement Specialist	Managing the bidding and selection of contractors	●
5.3	Retrofitting	General and Electrical Contractors	Performing physical building upgrades and installs	●
Phase 6	**Launch & Long-Term Stewardship**			
6.1	Testing	System Testing Specialist	Verifying that backup power and HVAC perform correctly	●
6.2	Awareness	Communications and Marketing Firm	Creating multilingual outreach and awareness campaigns	○
6.3	Evaluation	Program Evaluator	Measuring community impact and tracking success metrics	○

FUNDING & FINANCING STRATEGIES

It is fully acknowledged that these projects require significant upfront investment at a time when local budgets are balancing multiple priorities. While microgrids and CRCs offer long-term benefits in reliability, equity, and cost stability, their scale and complexity demand funding and financing strategies that extends beyond traditional capital allocations.

By blending federal, state, utility, private, and local funding sources, member agencies can leverage short-term opportunities while also establishing durable financial pathways to deliver and sustain projects. New state programs such as the Strategic Growth Council Community Resilience Centers Program and the California Public Utility Commission (CPUC) Microgrid Incentive Program, combined with expanded federal tax incentives, create timely opportunities to align WRCOG's priorities with available resources.

The intent of this section is to provide a menu of funding and financing strategies that reflect the diversity of WRCOG member agencies, highlight equity considerations, and outline practical steps for combining and sequencing different mechanisms. In doing so, WRCOG and its members can position themselves competitively for near-term grant rounds, reduce reliance on local budgets, and build a resilient financial foundation to support energy resilience investments for years to come.

FEDERAL INCENTIVES & PROGRAMS

The federal government provides a range of grant opportunities that can support resilience and energy-related projects across planning, capacity-building, and implementation. These resources are particularly important for capital-intensive investments such as microgrids and CRCs, which require significant upfront expenditures often beyond the capacity of local budgets.

The federal landscape today is dynamic, marked by both opportunity and uncertainty. Shifts in administration priorities, annual appropriations, and election outcomes influence which programs are emphasized, the scale of funding available, and the competitiveness of solicitations. Over the past year, several long-standing programs have been reduced or eliminated, while others have experienced shifting priorities or delayed appropriations. This volatility underscores the importance of monitoring federal opportunities closely and preparing projects to be competitive as funding priorities evolve. Local governments and regional agencies must be prepared to adapt quickly to changing federal priorities and to position their projects to align with evolving national goals. Agencies that are positioned with shovel-ready projects and strong partnerships are better able to secure federal dollars despite the changing landscape.

Since the development of the original Energy Resilience Plan, the federal funding landscape has continued to evolve. Several programs that were active during the first plan cycle such as earlier rounds of FEMA (e.g., Building Resilient Infrastructure and Communities) and U.S. Department of Energy (DOE) (e.g., Grid Resilience, Energy Efficiency and Conservation Block Grant) programs have now completed or exhausted allocations under the Infrastructure Investment and Jobs Act (IIJA). At the same time, new or renewed programs have emerged, including DOE's Community Microgrid Assistance Partnership (C-MAP) and the FEMA Safeguarding Tomorrow Revolving Loan Fund (STORM RLF), which offer expanded technical and low-interest financing pathways for local governments. Federal opportunities are increasingly being structured around multi-year appropriations, competitive rounds, and formula funding, making early project readiness and alignment with state implementation plans more critical than in the previous planning phase.

In this context, federal funding should be understood as one layer of a diversified approach. It is most effective when combined with state, utility, local, and private sources to create a resilient funding portfolio that can advance near-term projects while sustaining long-term energy resilience investments. Programs identified in the matrix highlight opportunities for both microgrids and CRCs, ranging from FEMA hazard mitigation and DOE grid resilience programs to the U.S. Department of Housing and Urban Development (HUD) flexible community development resources. These federal programs provide a foundation for WRCOG's funding strategy but will be most effective when layered with state and local sources to reduce reliance on uncertain federal cycle.

Community Microgrid Assistance Partnership (C-MAP)

DOE TA + limited direct funds to help communities plan/design microgrids

Org	DOE
Eligible Uses	Microgrid scoping, feasibility, design, optimization;
Deadline	2025 round selected; next NOFO TBD
Award Range	Varies; 2025 cohort total ≈ $8M across 14 projects (≈$5.5M direct + $2.6M TA)

Grid Resilience State & Tribal Formula Grants

Annual formula funds to states/tribes for grid hardening; subawards per state plan (CEC/Cal OES).

Org	DOE – Grid Deployment Office (via State of CA)
Eligible Uses	Grid hardening, distribution upgrades, resilience, DER integration
Deadline	State application window opened Feb 2025; annual
Award Range	Varies by state; subawards per CA plan

Grid Resilience & Innovation Partnerships (GRIP)

Competitive grants for grid modernization, resilience, DER integration, microgrids (Smart Grid/Innovation tracks).

Org	DOE – Grid Deployment Office
Eligible Uses	Microgrids, storage, DER controls, community resilience
Deadline	Prior rounds awarded FY24–25; next FOA TBD
Award Range	Varies; past selections range from tens to hundreds of millions

Safeguarding Tomorrow Revolving Loan Fund (STORM RLF)

FEMA capitalization grants create state RLFs offering low-interest loans to local governments for mitigation; loans may be used as non-federal match for HMA.

Org	FEMA (capitalizes state RLFs)
Eligible Uses	Hazard-mitigation capital incl. resilience hardening that reduces risk
Deadline	Recurring NOFOs to states
Award Range	Loan amounts vary by state plan

Learn more about each program by clicking on their respective boxes.

FEDERAL INCENTIVES & PROGRAMS

Community Development Block Grant (CDBG)

Annual formula funds to entitlement cities/counties (and via State to non-entitlements) for community facilities benefiting LMI residents.

Org	HUD
Eligible Uses	Public facilities, CRC build/retrofit, accessibility
Deadline	Annual (local action-plan cycles)
Award Range	Varies by allocation

Community Development Block Grant – Disaster Recovery (CDBG-DR)

Supplemental funds after presidential disasters for long-term recovery & mitigation; flexible infrastructure uses.

Org	HUD
Eligible Uses	Resilient public facilities, infrastructure serving impacted areas
Deadline	Issued per federal disaster appropriation
Award Range	Varies by appropriation

Energy Efficiency & Conservation Block Grant (EECBG)

Formula + small competitive program for EE/climate. Local gov formula windows are closed; Tribal applications due May 31, 2025.

Org	DOE – SCEP (EERE)
Eligible Uses	EE retrofits, planning
Deadline	Locals closed; Tribal due May 31, 2025
Award Range	Varies

Renew America's Schools (Prize/Grants)

Competitive for K–12 energy upgrades (LEAs).

Org	DOE – SCEP
Eligible Uses	HVAC/EE, solar/storage at schools
Deadline	2025 prize closed Apr 3, 2025
Award Range	Varies

STATE INCENTIVES & PROGRAMS

California provides one of the most robust state-level funding environments in the country for resilience and clean energy. State grants and incentive programs are particularly well-suited for WRCOG's priorities, offering direct support for facility upgrades, distributed energy resources, battery storage, and community-serving infrastructure. For microgrids and CRCs, these programs represent some of the most aligned and accessible funding sources.

The state funding landscape continues to evolve, with new opportunities emerging while others sunset or shift focus. Several one-time initiatives active at the time of the original WRCOG Energy Resilience Plan, such as Cal OES's PrepareCA Jumpstart and the initial Fairgrounds and Community Resilience Center grants, have concluded or are awaiting reauthorization. In their place, multi-year and recurring programs now form the foundation of California's resilience and clean-energy investment strategy, including the Strategic Growth Council's Community Resilience Centers Program, CPUC's Microgrid Incentive Program (MIP), and the CEC's Energy Conservation Assistance Act (ECAA) Loans.

Of particular importance for WRCOG is the Strategic Growth Council's Community Resilience Centers Program, which offers dedicated grant funding for the establishment and retrofitting of CRCs. This program is directly aligned with WRCOG's CRC vision, funding upgrades such as solar and storage, cooling and clean air centers, and services to support vulnerable populations.

Other state-administered opportunities in the matrix include multi-year resilience planning grants, technical assistance for microgrid deployment, and programs supporting extreme heat response and facility retrofits. These programs emphasize equity and regional impact, positioning WRCOG agencies to compete strongly when projects are bundled or designed with community-serving outcomes in mind.

Together, California's state programs represent some of the most relevant and accessible resources for WRCOG's priorities. By pairing state funding with federal and utility sources, member agencies can reduce project costs, accelerate timelines, and ensure resilience investments are distributed equitably across the region.

Because of the breadth of California's programs, WRCOG and its member agencies will need to prioritize those that are most closely aligned with their readiness and capacity and actively track program updates to remain competitive. Leveraging state funding in combination with federal resources and local contributions can significantly reduce project costs while positioning the region to advance equitable, community-centered resilience outcomes.

Community Resilience Centers (CRC) Program – Round 2

Direct capital + operations funding for new or retrofit community resilience centers that provide emergency services, energy resilience, and year-round programs.

Org	CA Strategic Growth Council (SGC)
Eligible Uses	Facility retrofits/new CRC construction, solar + storage, cooling and clean air spaces, resilience programming and staffing.
Deadline	NOFA expected mid-2026
Award Range	Varies (Round 1 ≈ $98.6 M)

Transformative Climate Communities (TCC) Program – Round 6 (Draft Guidelines)

Place-based climate and resilience investments in disadvantaged communities; CRC facilities can anchor project areas.

Org	SGC
Eligible Uses	Multi-project district investments including CRC sites, energy resilience, urban greening, active mobility.
Deadline	NOFA expected mid-2026
Award Range	$10M – $40M

STATE INCENTIVES & PROGRAMS

Self-Generation Incentive Program (SGIP)

Long-standing incentive program that provides rebates for behind-the-meter energy storage systems, including those serving critical facilities, low-income or disadvantaged communities, and resilience hubs.

Org CPUC (administered by SCE, PG&E, SDG&E, SoCalGas)

Eligible Uses Battery energy storage (stand-alone or paired with solar), particularly for CRCs, microgrids, and essential facilities.

Deadline Program reauthorized through 2028; ongoing rolling applications per IOU.

Award Range Varies by system size (~$150 – $1,000 / kWh); higher tiers for equity/ resilience projects.

EPIC GFO-24-312 – Advanced Grid Technology Acceleration Projects

Demonstration/deployment grants for advanced microgrid and grid-resilience controls technology.

Org CEC

Eligible Uses Microgrid controls, storage integration, smart resilience management.

Deadline Applications due Nov 14 2025

Award Range $4 M – $12M

Extreme Heat & Community Resilience Program (EHCRP)

Supports projects reducing extreme-heat risks and improving community resilience.

Org Cal OPR / LCI (ICARP)

Eligible Uses Cooling centers, shade trees, cool roofs, CRC retrofits, community education.

Deadline Round 1 awarded May 2025 (~$32 M to 46 projects); Round 2 TBD 2026

Award Range ~$250K – $5M

Regional Resilience Planning & Implementation Grant Program (RRGP)

Funds regional partnerships for climate resilience planning and early implementation.

Org Cal OPR / LCI (ICARP)

Eligible Uses Multi-jurisdiction resilience plans, CRC/ microgrid siting studies.

Deadline Round 1 awarded 2024; future round TBD pending budget restoration

Award Range Varies $250K – $1.5M

Fairgrounds & Community Resilience Centers Program

Capital upgrades for fairgrounds and community facilities serving as emergency shelters or resilience hubs.

Org CDFA (Fairs & Expositions)

Eligible Uses Backup power, HVAC, water storage, shelter improvements.

Deadline No active NOFA (2022–23 awards ≈ $150 M)

Award Range $5M – $10M

Microgrid Incentive Program (MIP)

$200 M competitive ratepayer-funded program for community-serving microgrids in disadvantaged or fire-prone areas.

Org CPUC via IOUs (SCE, PG&E, SDG&E)

Eligible Uses DER capital (batteries, solar, controls), interconnection and design support.

Deadline Tranche windows per IOU (2025–26)

Award Range $5M – $20M

GFO-25-301 - Distributed Resources for Innovative Vehicle Energization Strategies (DRIVES)

Demonstrates innovative DER and EV-grid strategies for community and fleet charging resilience.

Org CEC

Eligible Uses Resilient EV charging for CRC / community sites.

Deadline Pre-app workshop Oct 6 2025; applications Q1 2026

Award Range $2M – $8M

Community Energy Reliability & Resilience Investment (CERRI – GFO-23-312r2)

Technical assistance and enablement for community microgrids interconnected at PG&E feeders/substations.

Org CEC

Eligible Uses Grants for distribution system hardening and grid resilience infrastructure.

Deadline Round 2 closed Aug 29 2025; future round TBD 2026

Award Range $3M – $20M

Energy Conservation Assistance Act (ECAA) – Low-Interest Loans

Offers 1% interest loans to public agencies for energy-efficiency and clean-energy projects, including storage, EV charging, microgrids, and DERs. Acts as a revolving loan fund supporting capital projects that reduce greenhouse gas emissions and enhance resilience.

Org CEC

Eligible Uses Design and construction of DERs, battery energy storage, energy efficiency, EV charging, microgrid infrastructure, renewable generation.

Deadline Rolling; open year-round, subject to fund availability

Award Range Up to $30M per applicant; 1% interest, up to 20-year term

UTILITY & TAX INCENTIVES

In addition to state and federal funding programs, utility-administered incentives and federal tax mechanisms play a critical role in implementing microgrid and CRC projects. Many of these incentives, while created under state legislation, are implemented through California's investor-owned utilities (IOUs) and interface directly with project developers, facility owners, and local governments.

The landscape of utility and tax incentives has continued to mature since the release of the original WRCOG Energy Resilience Plan. The California Public Utilities Commission (CPUC) has expanded both the Microgrid Incentive Program (MIP) and the Self-Generation Incentive Program (SGIP) to prioritize disadvantaged and high fire-threat communities. These ratepayer-funded programs are among the most relevant and accessible pathways for WRCOG jurisdictions seeking to deploy microgrids and on-site energy storage.

This page summarizes current utility-administered incentives and federal credits that can be leveraged to advance CRCs and community microgrids across the WRCOG region.

Microgrid Incentive Program (MIP)

$200 million CPUC-approved fund to support community-serving microgrids in outage-prone or disadvantaged areas. Funds cover DERs, battery systems, interconnection, and control equipment.

Org CPUC

Eligible Uses Increase resilience at critical facilities (fire stations, schools, cooling centers); reduce outage impacts in low-income and vulnerable areas.

Updates

- CPUC allocated $200 M for IOU-run MIPs.
- Up to $14 M per community microgrid for design, interconnection, and generation/storage infrastructure.
- PG&E's Tranche 1 closed 2025; SCE/SDG&E rounds expected 2025–26.
- Also referenced under State Programs for policy-level coordination.

Solar Investment Tax Credit (ITC)

30% baseline tax credit for commercial-scale solar PV under IRC §48, with IRA bonus adders for domestic content, labor, or energy-community location.

Org DOE

Eligible Uses Solar PV systems serving CRCs or public facilities.

Updates

- Valid through 2032 under IRA §48.
- Tax-exempt entities access via Direct Pay (§6417).

Self-Generation Incentive Program (SGIP)

CPUC-administered, IOU-implemented rebate for behind-the-meter battery storage at critical and community facilities.

Org Southern California Edison (SCE)

Eligible Uses Battery storage paired with solar or stand-alone systems to maintain power at CRCs and essential facilities.

Updates

- Active through 2028 with declining incentive blocks.
- CPUC states Equity ($0.85/Wh) and Equity Resilience ($1.00/Wh) can reduce costs to near-zero for qualifying facilities (DACs, PSPS/high-fire-threat areas).
- Equity and Equity Resilience Adders cover up to 100% of installed cost in DACs or high-fire-threat zones.
- Also listed under State Programs due to CPUC governance.

Energy Community Bonus Credit

Adds up to +10% ITC/PTC for projects located in "energy community" tracts (former fossil sites, brownfields).

Org IRS / U.S. Treasury

Eligible Uses CRC or microgrid projects in eligible census tracts.

Updates

- Eligibility confirmed using Treasury/DOE maps.
- Some WRCOG cities may qualify near retired fossil or industrial zones.

SGIP Equity Resilience Adder

Enhanced SGIP incentive tier providing nearly full cost coverage for storage serving DACs and critical community facilities.

Org CPUC / IOUs

Eligible Uses Battery storage at CRCs, cooling centers, or shelters in high-risk areas.

Updates

- Up to $1,000/kWh incentive for qualifying facilities.
- Applies to Tier 2/3 Fire Threat Districts and PSPS-prone areas.

Demand Response & Resilience Tariffs

Programs compensating customers for reducing load or dispatching stored energy during grid stress, providing operational revenue for microgrids.

Org SCE, PG&E, SDG&E (CPUC approved)

Eligible Uses CRC or microgrid battery systems providing DR or VPP services.

Updates

- CPUC exploring standardized Resilience Tariff Framework (expected 2026).
- Current DR/VPP pilots active via IOUs and CAISO aggregators.

Charge Ready Transport Program

Financial incentives, infrastructure, and technical support to facilitate the installation and maintenance of EV charging stations.

Org SCE

Eligible Uses No-cost infrastructure design, construction, and electrical upgrades

Updates

- The application portal is closing on June 30, 2026
- Agreements must be signed by December 31, 2026

Investment Tax Credit (ITC) + Direct Pay (§6417)

Enables tax-exempt entities (cities, counties, nonprofits, tribes) to receive cash reimbursement equal to the ITC value.

Org IRS / U.S. Treasury

Eligible Uses Solar PV, standalone storage, microgrid components, CRC energy systems.

Updates

- Final Treasury guidance issued 2024.
- Bonus +10% for domestic content, prevailing wage, or energy-community siting.

FINANCING TOOLS

While grants and incentive programs can significantly reduce upfront costs, implementing microgrids and CRCs at scale will also require access to flexible, long-term financing. Private financing tools and local funding mechanisms allow WRCOG and its member agencies to advance projects that may not fully align with available grant cycles or that require local cost-sharing and match contributions. These mechanisms can also provide continuity between federal or state funding rounds, ensuring project momentum from design through construction.

Since the original WRCOG Energy Resilience Plan, new and expanded financing tools have become available to support energy resilience and decarbonization. California Infrastructure and Economic Development Bank (IBank) has introduced programs such as the Climate Catalyst Revolving Loan Fund and Safeguarding Tomorrow Revolving Loan Fund (STORM RLF) to provide low-interest and revolving loans for clean energy, storage, and hazard mitigation. Investor-owned utilities have also broadened on-bill and tariff financing options that help agencies implement efficiency and electrification upgrades with minimal upfront cost. Meanwhile, local governments across California are increasingly leveraging Energy Savings Performance Contracts (ESPCs) and Green Bonds to fund major upgrades through private investment and guaranteed energy savings. Together, these developments expand WRCOG member agencies' pathways for financing CRCs and microgrids.

Private financing approaches such as Power Purchase Agreements (PPAs), ESPCs, and other Public–Private Partnership (P3) models allow third-party investors to assume upfront capital costs in exchange for predictable, long-term payments or shared savings—an approach well suited for distributed energy and retrofit projects where operational savings can be reinvested in resilience upgrades. Local funding mechanisms such as green bonds, resilience bonds, and climate action funds also allow public agencies to raise capital directly for infrastructure improvements, with repayment supported by long-term savings or other stable revenue sources.

Collectively, these financing tools form a bridge between grant funding and long-term financial sustainability. They are especially valuable for WRCOG's diverse member agency jurisdictions, helping advance equitable and resilient implementation of CRC and microgrid projects across the region.

The following subsections outline two categories of mechanisms that can support WRCOG member agency energy resilience projects:

- **Private and Local Financing Tools**, which are financing structures that can be created or adapted by WRCOG and its member agencies in collaboration with private partners or through local initiatives. These mechanisms emphasize flexibility, local control, and the ability to tailor financing to community-scale energy and resilience needs.
- **State and Federal Loan Programs**, which are administered by state and federal entities and provide structured, low-interest, or revolving financing to support clean energy and resilience projects. These programs are externally managed and offer standardized terms that complement locally driven or privately structured financing approaches.

Private and Local Financing Tools

These mechanisms provide flexible structures for developing energy and resilience infrastructure without relying solely on grant funding. They are particularly relevant for projects where WRCOG or its member agencies seek to retain operational control but minimize capital exposure.

Table 13 Private and Local Financing Tools

Strategy/ Mechanism	Description
Power Purchase Agreement (PPA)	PPAs are one of the most common mechanisms for deploying distributed energy resources. A third-party developer finances, installs, and operates a renewable or storage system and sells the energy to the host at a fixed, typically lower-than-utility rate. For WRCOG jurisdictions, PPAs can enable solar + storage or microgrid projects at community facilities without upfront capital costs.
Energy Savings Performance Contracting (ESPC)	ESPC is a budget-neutral approach to support energy-efficient improvements and increase operational efficiency. State and local governments can implement ESPC projects across municipal portfolios, as well as promote and support non-municipal ESPC projects. ESPCs are structured to align the cost of energy efficiency improvements, from building audits to installation of high-efficiency equipment, with the energy savings they generate. ESPCs are agreements between an entity or customer such as a government agency, and an energy services company (ESCO). Under this arrangement, the customer retains ownership of the installed equipment, while the ESCO is responsible for operating and maintaining it over a contracted period of time. The contract guarantees a level of energy savings; if those savings are not achieved, the ESCO is obligated to reimburse the customer for the difference.
Energy Efficiency Incentives	Under the auspices of the CPUC, there are several IOUs, other portfolio administrators such as RENs and CCAs, and vendors that operate programs and measures for energy efficiency (EE) upgrades. In Riverside and San Bernardino Counties, the Inland Regional Energy Network (I-REN) offers public agencies EE incentives based on savings at the meter. Additionally, there are several other IOU and Statewide Programs that offer incentives and rebates for EE projects. All of these incentives can be beneficial for increasing resiliency of buildings and CRCs.
On-Bill Financing / Tariff Program - Southern California Edison (SCE)	Offers zero-interest on-bill repayment for small commercial and municipal customers (≤ 100 kW) completing efficiency or electrification upgrades. Ideal for smaller CRC retrofits involving HVAC, lighting, or limited battery storage.
Tax-Exempt Lease-Purchase (TELP)	TELPs are lease-to-own structures that allow public agencies to acquire energy systems without issuing voter-approved debt. Payments are typically made from operating budgets or energy savings. Many California school districts and local governments have used TELPs to install solar, storage, and efficiency upgrades quickly while retaining ownership after the lease term.
Green / Climate Bonds	Green bonds are debt instruments dedicated to financing projects with environmental or climate benefits. Issued by entities such as local governments or JPAs, they can offer lower interest rates due to high investor demand for sustainable investments. Unlike traditional bonds, they require adherence to Green Bond Principles or Climate Bond Standards to ensure transparency and accountability. Proceeds can fund or refinance projects such as energy efficiency upgrades, renewable energy systems, EV and clean transportation infrastructure, and climate adaptation or environmental protection initiatives.
Environmental Impact Bond (EIB)	An EIB is an innovative financing tool that uses a pay-for-success approach to provide upfront capital from private investors for environmental projects, either to pilot an innovative approach whose performance is viewed as uncertain or to scale up a solution that has been tested in a pilot program.
Revenue or General Obligation (GO) Bonds	Bonds remain one of the most familiar tools for large-scale infrastructure projects. Revenue bonds are secured by project revenues, while GO bonds are backed by property taxes and generally require voter approval. For WRCOG, these can finance high-impact regional microgrid hubs or CRC networks.

Case Studies



City of San Leandro, CA

ESPC

The City of San Leandro implemented a comprehensive energy efficiency and solar upgrade program across multiple municipal facilities including the Water Pollution Control Plant, city buildings, and street lighting in partnership with the energy services company Climatec, with financial support and oversight from the California Energy Commission (CEC).

Contract Amount
Total value of the performance contract was approximately $5.2 million.

Scope
Included LED lighting retrofits, HVAC upgrades, citywide smart lighting infrastructure with remote monitoring and control, and installation of solar PV systems.

Impact
Reduced utility costs and greenhouse gas emissions by 1,390 TCO2e annually, while improving building performance.

Savings
Slated to save the City $8 million over the next 15 years. Immediate annual cost reductions began following project implementation due to lower electricity usage and maintenance needs.

Financing
Used an ESPC to fund the project with no upfront capital investment, repaid through guaranteed energy savings on utility bills, structured so that the improvements paid for themselves over time. The CEC also awarded the city a $2 million grant to support solar and energy infrastructure enhancements.



County of Los Angeles, CA

ESPC

Los Angeles County implemented a multi-agency Energy Savings Performance Contract (ESPC) initiative spanning county facilities, federal laboratories, sanitation districts, and school campuses to advance large-scale energy efficiency, renewable generation, and water conservation improvements.

Scope
Included energy efficiency retrofits, solar and biogas installations, and water conservation measures across hundreds of buildings.

Partnerships
CEG Solutions, LLC (NASA JPL), Schneider Electric (Hacienda La Puente USD), Various qualified Energy Service Companies (LA County Sanitation Districts).

Savings
Generated over $1.6 million in annual utility savings (e.g., NASA JPL and HLPUSD combined) and significant energy use reductions, for example, 44,000 MMBtu/year at JPL.

Financing
NASA JPL: $23 million ESPC contract with CEG Solutions, LLC under the DOE's ESPC program. Hacienda La Puente USD: $5.3 million funded via Proposition 39 and ESPC with Schneider Electric. LA County Sanitation Districts: ESPCs for Warren Facility and Valencia WRP.

Recognition
Cited as a model for large-scale municipal ESPC implementation. NASA JPL ESPC received the 2016 Federal Energy & Water Management Award and the National Energy Project of the Year from the Association of Energy Engineers.



San Francisco Public Utilities Commission (SFPUC)

GREEN BONDS

The San Francisco Public Utilities Commission (SFPUC) has issued more than $3 billion in certified green bonds since 2015 to fund critical upgrades to the city's water, wastewater, and power systems in support of its climate resilience and sustainability goals. These bonds have financed a wide range of projects across SFPUC's enterprise utilities, including solar, hydro, and biogas energy generation under Hetch Hetchy Power; sewer and wastewater infrastructure through the Sewer System Improvement Program (SSIP); CleanPowerSF renewable infrastructure; and citywide green stormwater and flood mitigation systems.

Partnerships
Climate Bonds Initiative (certification), Sustainalytics (third-party verifier), CleanPowerSF and Hetch Hetchy Power (implementation agencies), major financial institutions (underwriters)

Financing
SFPUC has issued over $4 billion in green bonds since 2015. These are certified under the Climate Bonds Standard and repaid through utility revenues, with no additional burden on ratepayers. A major issuance in July 2024 totaled $1 billion, funding SSIP improvements with both taxable and tax-exempt bonds to attract a broad investor base.

Impact & Recognition
Projects financed by SFPUC's green bonds have increased water storage, expanded green infrastructure for stormwater management, and upgraded renewable energy generation facilities, avoiding over 57,000 metric tons of CO_2 annually (as of FY21). SFPUC was the first U.S. municipal issuer to receive Climate Bonds Initiative (CBI) certification for water infrastructure (2016) and was recognized by Environmental Finance for its innovative green bond program, including the historic listing of a $342 million taxable green bond on the London Stock Exchange—the first of its kind for a U.S. municipal issuer.

STATE & LOCAL PROGRAMS

In addition to external grant programs, several local and regionally deployable financing mechanisms are already available to WRCOG and its member agencies. These existing tools provide flexible, low-cost capital that can be tailored to support microgrid and CRC implementation. Many of these options are administered by IBank, which offers revolving loan funds for infrastructure and clean energy projects that can be accessed directly by local jurisdictions.

Table 14 State and Federal Loan Programs

Program Administering Organization	**Description**
CLEEN (Clean Energy Loan Program) California IBank – CLEEN Center	Provides low-interest financing for public clean-energy and GHG-reduction projects. Eligible uses include CRC retrofits, distributed storage, EV charging, and renewable generation.
Infrastructure State Revolving Fund (ISRF) California IBank	Offers flexible, long-term loans for public infrastructure and energy improvements. WRCOG jurisdictions have previously used ISRF loans for lighting and water system upgrades, and similar terms could support CRC and microgrid implementation.
Climate Catalyst Revolving Loan Fund California IBank	Provides patient capital for clean energy, storage, and resilience projects. The program prioritizes innovative or early-stage projects that may lack access to traditional debt markets.
Safeguarding Tomorrow Revolving Loan Fund (STORM RLF) FEMA / Cal OES	State-managed revolving fund capitalized by FEMA grants to support hazard-mitigation and resilience investments. Can fund microgrid or CRC hardening projects while serving as non-federal match for FEMA grants.
Energy Conservation Assistance Act (ECAA) – Low-Interest Loans CEC	Provides 1% interest loans to public agencies for energy-efficiency and clean-energy projects, including renewable generation, battery storage, EV charging, and microgrid infrastructure. The program acts as a revolving loan fund, allowing repayments to be reinvested in future projects. Eligible uses include design and construction of distributed energy resources, lighting and HVAC upgrades, and electrification measures that reduce greenhouse gas emissions and enhance resilience.

KEY CONSIDERATIONS

Building on the preceding analysis of funding and financing mechanisms, this section outlines key considerations for prioritization, risk management, and implementation sequencing as WRCOG and its member agencies move from feasibility to deployment of microgrids and CRCs.

These considerations are designed to guide WRCOG in translating technical feasibility into funding readiness—helping agencies identify which projects to advance first, how to layer and combine available funding tools, and how to prepare for grant applications and long-term management.

Funding & Financing Strategy Considerations

When developing a funding and financing strategy for energy resilience initiatives, WRCOG and its member agencies should carefully assess a range of foundational considerations to ensure long-term success and sustainability. Each decision, from the scale of the project to the availability of internal resources and external partnerships, can significantly influence eligibility for grants, the feasibility of financing tools, and the overall capacity to deliver and maintain projects. By thoughtfully addressing the factors outlined in Table 22, local governments and agencies can align their strategic planning with realistic funding pathways, reduce risk, and build the institutional support necessary to implement impactful, community-centered resilience solutions.

Considerations

Are you seeking funding and/or financing for a single plan or project or a program of projects?

- Initiative type will inform grant eligibility, and which financing tools are appropriate
- Funding (grant) opportunities often require/favor projects that are shovel-ready or sufficiently well-defined prior to selection.
- Grant opportunities may not support a program of projects
- Grant opportunities are finite and do not provide long-term financing for operation and maintenance of successful grantees

What level of resourcing (staff time, capabilities, funding) do you have available?

- Grant applications may require significant staff time and resources to complete
- Establishing new financing tools may require significant resources, expertise, and public involvement.
- If WRCOG and its member agencies are resource constrained, the opportunity cost to invest resources into grant applications/establishing new financing can be prohibitive
- WRCOG and its member agencies should prioritize projects and funding and financing that match their ability to secure necessary sources and deliver projects.

Do you have internal and external champions?

- Building consensus with internal and external champions and stakeholders is key to effective project prioritization and delivery
- When raising new revenue mechanisms or financing tools, internal and external champions will play a key role in building support and communicating messaging

Do you have local funding sources/ financing in place/available?

- In some cases, federal and state grants require a local match, which can be burdensome for jurisdictions and agencies
- If local financing tools and revenue mechanisms are already in place, this may support local match funding and support a diversified financing approach to deliver resilience projects
- If local financing tools and revenue mechanisms are already in place, this may limit local government and agency capacity to take on more financing

Do you have local, regional, multi-jurisdictional, and cross-sectoral partners?

- Non-government and local agency partners provide opportunities to share resources and burdens, especially when applying for grants
- Local partners may play an integral role in the successful, long-term operation and maintenance of resilience projects
- Partnerships provide opportunities to reduce risk and reliance on a single funding source.

Centering Equity

Funding and financing strategies for resilience and recovery should consider the financial needs of and the potential impacts of funding and financing opportunities on vulnerable and disadvantaged populations. Strategies that do not adequately address current inequities can negatively impact communities. The following examples are not exhaustive, and a holistic assessment of impacts should be undertaken before implementing funding and financing strategies.

- Taxes, fees, and charges can inadvertently increase financial burdens on low-income households, which reduces a household's ability to pay for other essential needs.
- Communities with fewer resources will have less capacity to pursue and secure funding and financing, which if left unchecked, can reinforce existing inequities.
- Financing may require innovative thinking to avoid existing inequities in institutional financing tools, such as the impacts of downgraded credit ratings post-disaster on a community's long-term ability to secure affordable financing and to pay for resilience and recovery projects.

When integrating equity into funding and financing strategies, local governments should determine how funds are raised and spent. It is important to include community representation in the decision-making process, including low-income, communities of color, and frontline communities. Other equity considerations for funding and financing are outlined in **Table 15**.

Table 15 Examples of Equity Integration

Equity Consideration	Example
Participatory Funding & Financing Process Community members actively participate in deciding which funding and financing sources are pursued and allocated, promoting transparency and inclusivity.	The Duwamish Valley Program in Seattle, Washington, has developed a funding, finance and value capture program that centers residents' voices when pursuing grant funding from federal and state programs to make neighborhood-level resilience investments.
Participatory Budgeting Process Community members propose and vote on projects to determine how portions of public budgets are spent.	The City of Vallejo employs a participatory budgeting process in which community members recommend to the City Council how to spend part of a public budget. The City has allocated over $8.3 million to fund a total of 47 projects, while engaging over 20,000 residents of Vallejo.

Preparing to Apply for Grant-Funding Opportunities

It is essential for WRCOG and its member agencies to prepare for grant opportunities ahead of time to avoid reacting to opportunities in an ad-hoc manner. Strategic and proactive grant funding strategies save time and resources, improve competitiveness, strengthen partnerships, maximize funding opportunities, enhance grant management capacity, and align funding opportunities with community and stakeholder priorities.

Grant-Funding Opportunity Preparatory Steps

1. **Identify a grant monitoring and application lead** or coordinator, and where resources allow establish a grant team including a project manager, finance, legal, and subject matter experts to manage the grant identification, application, and management processes.
2. **Conduct an eligibility and feasibility assessment** to understand grant eligibility requirements, understand organizational capacity to apply for a manage grants, and evaluate the local match or cost-share requirements.
3. **Explore partnering opportunities** with neighboring governments, agencies, and community-based organizations to reduce administrative and cost burden, increase grant impact, and develop more compelling and impactful grant applications.
4. **Review the Notice of Funding Opportunity** once it is released to confirm alignment projects with the purpose and objectives of the grant opportunity and to understand the specific grant application requirements.
5. **Prepare for the grant application process** by registering for required systems and submission portals, gathering required documentation, developing organizational mission statements and organizational charts, and gathering letters of support or Memorandums of Understanding (MOU) from partners, if required.
6. **Identify and engage required technical assistance** through the grant program if assistance is offered or from third parties as part of grant application development.
7. **Develop grant application materials** including a proposal timeline with internal deadlines, draft a compelling narrative and needs statement, a detailed budget and rationale, evaluation process and metrics, and ensure aligned to the grant requirements and purpose.
8. **Complete internal review and approval** to ensure completeness and compliance against grant requirements, secure leadership buy-in and support, and review for clarity, grammar, and formatting.
9. **Submit the grant application** through the correct portal before the deadline, confirm receipt of the submission via system confirmations or email confirmations (if permitted), and save a complete copy of the submission application and receipts.
10. **Plan for long-term sustainability** of the project beyond the performance period, including alternative funding and financing sources and integration of the project in capital and operational financial plans.

Competitive funding cycles often require rapid response. To remain prepared, WRCOG can build on the grant management practices established through regional initiatives such as SCAG's Resilience Toolkit. Key actions include:

- **Developing a grant readiness checklist** to confirm eligibility, match funding, and documentation needs before solicitations open.
- **Maintaining project profiles** summarizing each CRC or microgrid's status, cost, and benefits to streamline future applications.
- **Pre-developing narratives and benefit quantifications** (e.g., GHG reduction, social vulnerability impact) to accelerate submittal timelines.
- **Formalizing partnerships** with utilities, CBOs, and private entities to include letters of support and defined roles before applications launch.
- **Coordinating post-award administration** through shared reporting, invoicing, and compliance tracking tools managed at the WRCOG level.

These steps will position WRCOG and its member agencies to secure—and effectively manage—state and federal funding at scale.

Prioritization Considerations & Criteria

Not all WRCOG projects will advance at the same pace or scale. Establishing clear prioritization criteria will be essential to guide resource allocation and align near-term investments with high-impact opportunities. Prioritization should consider:

- **Community vulnerability and critical service needs**
  Emphasize CRCs and microgrid projects that serve vulnerable populations, provide essential services during outages, or align with SGC equity objectives.
- **Technical and financial readiness**
  Advance projects that already have completed feasibility studies, utility interconnection assessments, or established partnerships.
- **Funding competitiveness**
  Target projects that align closely with open or recurring federal and state solicitations (e.g., SGC CRC Program, CPUC MIP, DOE GRIP).
- **Regional balance**
  Ensure investments are distributed equitably across WRCOG's subregions to reflect differing levels of risk exposure and fiscal capacity.

Match Funding & Administrative Burden

While federal and state grants can substantially offset costs, they often require local match and extensive administrative oversight. Smaller WRCOG member agencies may face constraints in both areas. To reduce burden and enhance competitiveness, WRCOG can:

- **Serve as a regional applicant or fiscal agent**, coordinating pooled submissions to reduce duplicative effort.
- **Establish a shared grant match fund**, supported by IBank loans or revolving local contributions, to meet cost-share requirements.
- **Provide centralized administrative support**, including procurement, reporting, and compliance tracking across funded projects.

These steps would allow member agencies with limited staff or fiscal flexibility to access large-scale funding while maintaining compliance and accountability.

Risk-Sharing Between Public Agencies, Utilities, and Private Developers

Implementing microgrids and CRCs requires collaboration across multiple sectors. Risk—both financial and operational—can be distributed through structured partnerships that leverage each partner's strengths:

- **Public agencies** provide leadership, access to sites, and alignment with community goals.
- **Utilities** can offer technical coordination, infrastructure integration, and operational support.
- **Private developers or ESCOs** bring financing, delivery, and long-term maintenance expertise.

P3 models, ESPCs, and PPAs can all help WRCOG member agencies shift risk while maintaining public ownership or oversight of assets.



Combing Multiple Strategies

Few projects will be funded by a single source. The most effective pathway will involve stacking and sequencing funding tools to maximize leverage. For example:

- Layering tax credits, SGIP rebates, and PPAs to cover capital and operating costs for CRC and microgrid installations.
- Using IBank loans or local bonds as bridge financing for projects awaiting federal reimbursement.
- Combining state planning grants (Cal OPR, CEC) with federal construction funds (FEMA, DOE) to move projects through phased development.

Next Steps

The final phase of the financing strategy involves integrating these funding and financing considerations into the Implementation Plan phases described in previous sections. This will allow funding readiness to evolve alongside project design and phasing.

Short-Term
0 – 12 months

- Identify priority projects with strong funding alignment (SGC CRC Program, CPUC MIP, FEMA HMGP).
- Establish a regional match fund and internal grant coordination team.
- Pre-position "shovel-ready" projects by completing conceptual engineering and cost estimates.

Medium-Term
1 – 3 years

- Launch applications for state and federal implementation grants.
- Advance local and bank-financed projects to construction phase.
- Formalize public–private partnership models and utility agreements for multi-site microgrids.

Long-Term
3+ years

- Institutionalize resilience financing framework into ongoing capital planning.
- Expand regional cost-sharing mechanisms for maintenance, reinvestment, and system upgrades.
- Use performance metrics from early projects to inform future funding rounds and policy advocacy.

By aligning funding prioritization, risk-sharing, and readiness actions, WRCOG member agencies can move confidently from planning to tangible outcomes—delivering resilient, equitable, and financially sustainable energy infrastructure across respective jurisdictions.

APPENDICES



APPENDIX A

Microgrid Implementation Details

Phase 1: Feasibility

Load Profiling

Inputs	Interval data	Interval data is a specific type of meter data that records **usage at fixed time steps** (intervals), typically captured in 15-, 30-, or 60-minute increments. It allows engineers to see the **"peaks and valleys" of energy use** throughout a 24-hour cycle, which is necessary for determining how much battery power is needed to cover sudden spikes in demand. 12 to 24 months of interval data is typically required. “Green Button” is a standardized, industry-wide format protocol for this data.
	Utility bills	Utility bills provide a high-level history of **monthly consumption** (kWh) and the **highest recorded demand** (kW) for the billing cycle.
	Future expansion plan(s)	These documents can include details or any planned new construction, renovation, or building system installation. Examples include HVAC replacements or EV charging stations. The purpose of this analysis is to **prevent the microgrid from being "undersized"** on day one, allowing the design to accommodate the projected increase in electrical load over the next 5 to 10 years.
Actions	Cleanse raw data	This process involves **identifying and correcting gaps**, outliers, or "null" values in utility interval files to ensure the baseline model is statistically sound.
	Categorize loads by priority	This requires **sorting electrical loads into tiers** (Critical, Priority, and Interruptible) to program the microgrid controller's automated load-shedding sequences.
	Model peak demand events	Analysis is performed to pinpoint the exact timestamps and conditions of the highest energy usage to **determine the maximum discharge rate** required from the BESS.
Outputs	Load profile(s)	These are time-series visualizations and datasets that illustrate the facility’s energy consumption patterns over 24-hour cycles for various seasons and day types, which serve as the baseline for **energy capacity modeling**, allowing engineers to determine the total energy (kWh) the battery energy storage system and generation assets must store and generate daily. Subset can depict loads deemed critical, i.e., critical load profile.
	Peak demand report	This report identifies the maximum instantaneous power required by the facility, specifically highlighting the highest coincident peaks that the microgrid must be capable of supporting. It defines the **inverter and interconnect sizing**,

		ensuring the hardware has the physical capacity to handle the site's heaviest power surges without failing.
	Load criticality tiers	This is a structured list or table that ranks all facility loads into groups based on their necessity, ranging from mission-critical life-safety systems to non-essential aesthetic lighting. This serves as the **logic foundation for the microgrid controller**, providing the ruleset for automated load-shedding to prevent system collapse during an islanding event.

Resource Assessment

Existing Generation Sources		
Inputs	Asset nameplate data	Need to **compile technical specifications of existing generation sources**, such as diesel, PV inverters, or combined heat and power units. This is key to determining if existing equipment has the physical capacity and "grid-forming" capability to sustain an islanded load.
	O&M logs and health reports	Need to collate 2–3 years of maintenance history, run-time hours, and recent load-bank test results to assess the "**useful remaining life" of assets** and identify if they are reliable enough to serve as critical backup.
	Existing control architecture	Documentation of current Programmable Logic Controller (PLC), Supervisory Control and Data Acquisition (SCADA), or local controller settings and communication protocols (e.g., Modbus, DNP3) serves to **see if existing "brains" can be integrated into the new master microgrid controller or if they need a "retrofit kit."**
Actions	Determine controllability	Testing whether the existing generator can be remotely started, stopped, and throttled by an external signal to **ensure the microgrid controller can balance this source** with intermittent renewables in real-time.
	Evaluate fuel supply chain	Auditing on-site fuel storage (tank capacity) and the reliability of delivery contracts for diesel or natural gas to **calculate the how many days the microgrid can run without any external support**.
	Assess retrofit requirements	**Identifying if existing non-smart inverters or manual transfer switches need to be replaced** with smart, bidirectional hardware to provide an accurate "Integration Cost" that must be added to the project’s CAPEX during the feasibility study.
Outputs	Asset integration report	A formal **"Keep, Upgrade, or Decommission"** recommendation for every existing power-producing asset on

		site to informs the final system design by detailing how much of the existing infrastructure is actually reusable.
	Operating baseline model	A **simulation of how the site currently handles outages** using its existing equipment to serve as the "Base Case" for the financial model, against which the new microgrid's performance and savings are measured.
	Interface requirements specifications	A technical document outlining the communication and wiring changes needed to **link old assets to the new controller** to provide the Engineering phase with precise "handshake" requirements for the microgrid's software logic.

Prospective Generation Sources		
Inputs	Site physical surveys	These are architectural drawings, roof structural reports, and topographical maps that identify usable areas for equipment placement. These documents identify **"no-go" zones**, such as shaded areas or unstable soil, ensuring that the proposed assets are physically viable to install.
	Solar/wind resource data	This is location-specific meteorological data, such as global horizontal irradiance or wind speed averages, retrieved from databases like the National Renewable Energy Laboratory National Solar Radiation Database. It provides the **raw environmental potential** used to calculate how many kilowatt-hours a specific technology can produce annually at your exact coordinates.
	Local utility tariff and interconnection rules	This includes the utility's rate book and technical requirements for connecting DERs to the grid in a given service territory. This data establishes the **"value" of the energy produced** (avoided cost) and identifies **potential technical hurdles** that could increase project costs.
Actions	Evaluate land and roof suitability	Technical experts review the structural integrity of roofs and the soil composition of land to support the weight of solar racking or battery enclosures. This action **identifies necessary "hidden" costs**, such as roof reinforcements or extensive civil grading, before the project moves to the engineering phase.
	Calculate capacity factors	Engineers apply local weather data to specific equipment specs to determine the actual expected energy output over time. This calculation **determines if renewables alone can meet the critical load requirements**.
	Conduct shading and obstruction analysis	Engineers **model how nearby buildings, trees, or parapets will reduce solar production** throughout the day. Software like Helioscope or PVSyst can be used. This ensures that production estimates are conservative and realistic,

		preventing the over-sizing of financial returns based on overly idealistic sun conditions.
Outputs	Annual generation potential report	This is a **detailed projection of how much energy (kWh) each proposed source will produce** on a monthly and annual basis. This report serves as the primary data point for the financial model to calculate energy savings.
	Site constraints and placement map	This is a visual layout **showing exactly where solar arrays, batteries, and controllers should be physically located** on the property. This map guides the Engineering phase by defining the distance between components, which impacts wiring costs and voltage drop calculations.
	Preliminary technology selection	This is a finalized list of the **specific types and sizes of generation assets chosen for the site**. This preliminary selection of system architecture enables detailed electrical engineering and interconnection applications to begin.

Economic Modeling

Inputs	CAPEX estimates	This includes the quoted or estimated costs for all hardware (PV, BESS, controllers), soft costs (permitting, engineering), and physical installation labor. These figures establish the **total upfront investment required** to move the project from paper to reality.
	OPEX projections	This input tracks the **ongoing costs of running the system**, including maintenance contracts, equipment replacement reserves (e.g., inverter swaps), and fuel costs. It allows for the calculation of the "Total Cost of Ownership" over a microgrid's 20- to 25-year expected lifespan.
	Incentive and subsidy documentation	This includes data on federal tax credits, state-level grants, and utility rebates available for renewable energy and resilience projects, if applicable. Such inputs may significantly **reduce the effective net cost of the project**, often making the difference between a "go" or "no-go" decision.
Actions	NPV analysis	Analysts calculate the current value of all future energy savings and revenue streams, discounted back to today's dollars. This action **determines if the project creates more value over time than the initial cash investment**, accounting for the time-value of money.
	Sensitivity and risk modeling	This involves "stress-testing" the financial model by varying key assumptions, such as rising utility rates, fluctuating fuel prices, or lower-than-expected solar production. It

		identifies w**hich variables have the greatest impact on the project's profitability**, helping stakeholders understand the financial risks.
	Value-of-resilience quantification	The team estimates the monetary losses avoided during a grid outage, such as prevented spoilage, maintained production uptime, or life-safety preservation. This **translates the "insurance" aspect of the microgrid into a dollar value**, which often justifies projects that wouldn't survive on energy savings alone.
Outputs	Financial pro forma statement	A multi-year spreadsheet that projects the year-by-year cash flows, tax implications, and cumulative savings of the microgrid project. This document is the **primary tool** used by financial stakeholders or investors to **approve funding** and compare the microgrid against other capital projects.
	Simple payback and internal rate of return report	A summary report that highlights the number of years required to recoup the investment and the annualized percentage return the project generates. These metrics provide a quick **snapshot of the project's financial attractiveness** for executive-level decision-makers.
	Optimized financing recommendation	A final recommendation on the best way to fund the project, whether through direct ownership (CAPEX), an Energy Service Agreement (ESA), or a Power Purchase Agreement (PPA). This guides the procurement strategy by identifying the **most capital-efficient way to deploy the microgrid** based on the organization's tax status and cash availability.

Phase 2: Engineering

System Modeling

Inputs	Refined load and resource data	**Finalized load profiles and location-specific weather datasets**. These provide the necessary boundary conditions for the software to simulate real-world operations.
	Technology performance curves	Manufacturer data describing how efficiency changes with temperature and load levels. This enables the simulation to account for **real-world equipment degradation and efficiency losses** over time.
	Utility rate structures	Detailed tariff data including time-of-use rates, demand charges, and net-metering rules. This allows the model to calculate exactly when the BESS should charge or discharge to **maximize financial savings**.

Actions	Hourly dispatch simulation	Iterative performance modeling is conducted to see how the BESS and generation sources interact under various conditions. This **determines the optimal sizing** of the assets to ensure the lowest levelized cost of energy (LCOE).
	Sensitivity analysis	Testing how the system performs if variables like fuel prices or solar output fluctuate by 10–20%. This identifies **financial and operational risks**, ensuring the design is resilient to market or climate changes.
	Verify resilience compliance	Simulating the "Worst Case" weather day to confirm the system meets the minimum required hours of autonomy serves to guarantee that the microgrid will actually **fulfill its primary mission of keeping critical loads online** during a disaster.
Outputs	Finalized system sizing report	A document specifying the **exact kW of generation and kWh of storage needed**. This serves as the final "shopping list" for procurement and the technical foundation for the electrical design.

Electrical Design

Inputs	Facility as-built electrical drawings	Existing SLDs and panel schedules for the facility will serve to identifies the current **Point of Interconnection** and determines **which circuits are physically available for the microgrid to control**.
	Equipment data sheets	Technical specifications for the chosen inverters, batteries, and switchgear provide the **physical dimensions and electrical connection points needed** for accurate drafting.
	Site civil and topographical surveys	Maps showing existing underground utilities, soil conditions, and elevation changes are used to **prevents conflicts with existing infrastructure** and informs the design of concrete pads and conduit routing.
	Local electrical and fire codes	Thorough identification of specific regional requirements for battery ventilation, setbacks, and emergency shut-offs is key to **ensure the design is "permittable"** and will not be rejected by local building inspectors.
Actions	Draft microgrid SLDs	These newly developed schematics depict power flow from new sources to existing loads. These SLDs are the **primary document used for permits, interconnection applications, and construction guidance**.
	Protection coordination study	Calculating fault currents and setting breaker trip times for the existing and new gear **prevents "blind spots"** where a fault on a new solar array might accidentally trip the main building breaker.

	Design interconnection interface	Engineering the specific physical bridge (e.g., a new isolation switch) between the utility and the site ensures the microgrid can **"island"** (i.e., disconnect) from the main grid **safely without backfeeding** the utility.
Outputs	Detailed engineering package	A **set of stamped drawings** including SLDs, site plans, and wiring schedules. It serves to provide the "instructions" the construction team uses to physically build and wire the microgrid.

Controls & Communications Design

Inputs	Sequence of operations (SOO) requirements	Plain-language description of how the system should behave during specific events. Serves as the **logical blueprint** that the software engineers use to write the control code.
	Communication protocol list	List of the digital "languages" (e.g., Modbus, DNP3, etc.) supported by each piece of equipment. Ensures the **controller can "talk"** to the battery, solar, and meters without compatibility issues.
	Existing IT/network infrastructure	Documentation of onsite fiber, ethernet, or wireless networks that can be leveraged. Determines if the microgrid needs a **new dedicated network or can use existing facility communication lines**.
Actions	Map data communication paths	Designing the **physical and logical network** connecting the assets to the master controller. This is to ensure that data flows fast enough for the controller to react to grid fluctuations in milliseconds.
	Write automated control logic	Programming the "if/then" statements for load shedding and islanding. This serves to **automate the microgrid** so it **reacts to grid failure instantly** without human intervention.
	Configure HMI and monitoring dashboard	Designing the **user interface** that facility managers will use to monitor the system. This is to provide operators with real-time visibility and manual override capabilities if needed.
Outputs	Control logic and networking map	Technical d**iagram detailing the software triggers and the physical network**. This document is used during the Commissioning phase to verify that the system responds correctly to all sensor data.

Phase 3: Permitting

Utility Interconnection Application

Inputs	Stamped engineering package	Finalized **SLDs** and **Three-Line Diagrams** bearing a **Professional Engineer's seal**. These are required to be provided to the utility as the legally certified technical proof that the system is designed to industrial safety standards.
	Inverter and equipment certifications	Technical **"cut sheets" proving compliance** with standards like IEEE 1547 and UL 1741. These are necessary to confirm the hardware has "anti-islanding" and grid-support features that prevent it from feeding power into a dead utility line.
	Interconnection application fees	Non-refundable **deposits and processing fees** required by the utility to open a project queue position.
Actions	Submit formal interconnection request	Filing the **specific tariff-based application** (i.e., California Public Utilities Commission Electric Rule 21) with the applicable utility department. This submittal secures the project's place in the utility's technical review line.
	Facilitate utility impact studies	**Coordinating with utility engineers** as they simulate how the microgrid affects local voltage and transformer capacity. This serves to identify if the utility needs to upgrade its own equipment (e.g., larger transformers) to accommodate the new power source(s) of the microgrid.
	Negotiate interconnection agreement	This negotiation establishes **the long-term legal rights and responsibilities** for both the site owner and the utility.
Outputs	Signed interconnection agreement	The **executed legal contract** allowing the microgrid to operate in parallel with the utility. This document allows serves as the primary "green light" needed to finalize project financing and start construction.

Plan Check

Inputs	Site plan and plot maps	Scaled drawings showing the **physical location of all equipment**, including setbacks from property lines and buildings. These are necessary for zoning and fire officials to verify that equipment won't block emergency access or violate land-use laws.
	Fire mitigation and BESS safety plan	A detailed report on battery chemistry, thermal management, and emergency shutdown procedures is typically **required by the local fire department**.
	Structural and civil calculations	**Engineering reports** proving the roof can hold the solar panels or the ground can support heavy battery

		enclosures. These are **required** to demonstrate that the installation won't lead to structural collapse or significant soil erosion during a storm.
Actions	File building and electrical permits	Submitting the full engineering set to the local building department for **"Plan Check."** Doing so is the pathway to procuring the legal authorization required to break ground and begin physical installation on the site.
	Conduct environmental/zoning review	This may be required if the project is determined to require **special land-use permits or noise variances** for generation sources.
	Address plan check comments	This is required following "Plan Check." **Revising the engineering drawings based on specific feedback** or corrections requested by the city's reviewers ensures the final design aligns perfectly with local safety interpretations before a permit is issued.
Outputs	Approved permit set	Final set of engineering drawings with **"City Approved" stamps and an issued building permit**. This set provides the construction crew with the final, legally-compliant instructions for the physical build.

Phase 4: Construction

Procurement

Inputs	Bill of materials	This comprehensive list of all hardware, including specific part numbers and quantities derived from the engineering package serves as the master ordering document to ensure that every component is accounted for.
	Vendor lead-time schedule	Tracking the manufacturing and shipping timelines provided by equipment suppliers allows the project manager to anchor the construction start date to the arrival of "long-lead" items like custom switchgear or transformers.
Actions	Purchase orders	Formally executing contracts with vendors to secure equipment and lock in delivery dates moves the project from the planning stage into a legal commitment with hardware manufacturers
	Factory acceptance testing	Reviewing factory acceptance testing (FAT) reports performed by the manufacturer at the factory before the equipment is shipped is important to prevent the necessity of costly "field fixes."
	"Just-in-time" delivery	Scheduling the arrival of heavy equipment (like transformers) to coincide with the presence of cranes and rigging crews is vital and minimizes the time expensive

		equipment spends sitting on-site, reducing the risk of theft, weather damage, or double-handling costs.
Outputs	Equipment delivery tracking log	Having a dynamic schedule showing the real-time status and expected arrival of every major system component provides the construction manager with the visibility needed to adjust labor schedules based on shipping updates.

Site Preparation

Inputs	Civil and structural engineering plans	Stamped drawings showing the depth of trenches, the thickness of concrete pads, and the location of underground conduits. These are necessary to provide the civil contractor with the exact physical dimensions and safety standards required for site infrastructure.
	Geotechnical survey results	This data on soil density, moisture levels, and resistivity informs the design of the equipment pads and the grounding grid to ensure the system doesn't settle or fail during a lightning strike.
Actions	Trenching and conduct replacement	Excavating new paths for power and communication lines and laying the protective piping that will house the cables is often necessary with new microgrid installation.
	Equipment foundations	Constructing code-compliant concrete pads and supports for the solar racking, battery containers, and backup generators is typically necessary.
Outputs	Civil completion certificate	This formal sign-off from the site engineer or inspector confirms that the foundations and trenches meet the design specifications and triggers the "Go-Ahead" for the electrical team to begin mounting and wiring the equipment.

Electrical Installation & Mechanical Assembly

Inputs	Approved electrical permit set	The final, city-stamped blueprints that dictate how the wiring and protection must be installed are how the electricians follow the legally authorized version of the design to avoid failing future inspections.
	Health and safety plan	This project-specific document outlining the specific Lock-Out/Tag-Out (LOTO) and safety protocols for working on live or near-live electrical systems is essential to protect the lives of the installation crew by preventing accidental energization of the system during construction.

Actions	Mount and secure equipment	Heavy machinery is required to position battery enclosures, inverters, and solar arrays onto their permanent foundations.
	Pull and terminate cables	Installing the copper or aluminum wiring through conduits and making the physical connections at the terminals of each device is required.
Outputs	As-builts construction markup	This preliminary version of the drawings showing any minor field adjustments made during the physical build is the essential starting point for the Commissioning phase, as the testing team needs to know exactly how the system was wired.

Phase 5: Commissioning

System Integration

Inputs	Commissioning script and test plan	This step-by-step technical document detailing every functional test required by the engineers and manufacturers provides a standardized methodology to ensure every operational mode, such as "peak shaving," is verified before the system is left unattended.
	Final control logic code	The finished software "brain" that has been programmed and uploaded to the master microgrid controller includes the operational instructions the system will follow once the breakers are closed and the system is energized.
Actions	Black start testing	This test is purposeful disconnection from the grid to verify the system automatically switches to BESS + onsite generation power without dropping loads. It serves to validates the primary resilience goal of the project, proving the system can maintain power during a real-world utility outage.
	Communication link integrity test	Testing the data flow between the central controller and every sensor, meter, and inverter on the network is necessary to ensure the "brain" of the microgrid is receiving accurate, real-time data to make safe and efficient dispatch decisions.
Outputs	Certified functional test report	This documented log of all successful tests proving the system is stable and performing according to the engineering design acts as the technical evidence required to request a final inspection from the utility and the local building department.

Permission to Operate

Inputs	Protection coordination report	The final, stamped settings for the protective relays that govern the interface between the grid and the microgrid are used to inform the utility of the exact thresholds where the microgrid will automatically disconnect to prevent electrical accidents.
	Final as-built drawing set	The "as-installed" blueprints that reflect the exact physical and electrical state of the system after construction provide the utility with a permanent and accurate record of the system they are authorizing to operate on their network.
Actions	Utility awareness test	This test to demonstrating the system's ability to isolate from the grid during a simulated failure while under utility supervision is required to satisfy the utility's legal safety requirements, confirming the microgrid will not "backfeed" electricity onto a dead utility line.
	Final AHJ sign-off	Coordinating a final walkthrough with local building and fire inspectors to close out all open permits is required to confirms the system meets all local fire, life-safety, and building codes.
Outputs	Permission to operate letter	Upon completion of requisite tests, this official legal authorization from the utility to begin permanent, energized, and parallel service marks the official "Commercial Operation Date" and allows the owner to begin accruing energy savings and incentives.

Final Handover

Inputs	Operations and maintenance manual	Procuring a comprehensive binder containing all component manuals, warranty certificates, and preventative maintenance schedules is vital and serves as the permanent "Owner’s Manual," providing instructions on how to troubleshoot issues and maintain the system's health.
	Emergency response plan	A clear, simplified guide for facility staff on how to safely shut down the microgrid during a site emergency is critical to protect personnel and property by ensuring site operators can react quickly if the automated systems require manual intervention.
Actions	Operator training sessions	Providing hands-on instruction to the owner's team on how to use the monitoring dashboard and interpret system alerts is essential.

Appendix A
Microgrid Implementation Details

	Digital credentials and admin rights transferal	Handing over the passwords and administrative control for the controller software and monitoring portals formally ends the developer's access and control, giving the owner full autonomy over their new energy asset.
Outputs	Final project closeout binder	The complete collection of all stamped drawings, permits, warranties, and the PTO letter delivered to the owner represents the final contractual deliverable, signaling the formal completion of the project and the start of the warranty period.

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Attachment

WRCOG Energy Resilience Plan 2.0 Regulatory Memo: “Pathways and Pitfalls to Local Government Microgrid Adoption to Address Reliability/Resiliency Issues”

POLICY ANALYSIS FOR THE PUBLIC AND PRIVATE SECTORS
M.CUBED

Pathways and Pitfalls to Local Government Microgrid Adoption to Address Reliability/Resiliency Issues[1]

Need for Increased Resiliency Prompts Interest in Microgrids

Electrical outages – including those associated with Public Safety Power Shutoffs (PSPS) – are causing local governments to examine the use of energy systems that can bolster reliability, especially during periods of extreme weather. An outage that occurs during high temperatures, rendering air conditioning inoperable, can make buildings unoccupiable, forcing municipal workers, students, and residents to stop work and study, and shelter elsewhere. Behind-the-meter (BtM) energy systems can support "resiliency centers;" community-based facilities designed for use during natural disasters and social disruptions that offer shelter and crises resources.

Historically, public and private sector entities have adopted fossil fuel backup generators (BUGs) to generate electricity during grid outages. However, BUG runtimes are constrained by air quality rules, and the need for diesel resupply. As costs for renewables and battery storage have declined, interest in deploying integrated systems as part of a localized energy grid that can operate independently or in conjunction with the main power grid has grown.

This brief provides an overview of the opportunities, challenges, regulatory issues, and economics associated with developing a microgrid at public sector facilities in Southern California. A microgrid is a local energy system that can disconnect from a utility's grid and operate autonomously to provide electricity. Microgrids can be attractive to

- Provide resilient electric power to critical infrastructure and other electricity consumers, ensuring that the facilities can continue to operate during power outages.
- Deliver energy services at a lower cost than grid power to isolated communities.
- In high fire risk areas, offer a lower-cost alternative to undergrounding distribution infrastructure.

A microgrid consists of one or more energy-generating components that can provide power in the event of a grid outage (see Figure 1). It includes control systems to interact with the local grid and dispatch power to loads, as well as equipment to manage the grid connection. A renewable-energy microgrid may incorporate solar generation and battery storage, which can provide significant value during grid-connected operation.

[1] Steven Moss, M.Cubed Partner, and Ari Halberstadt.

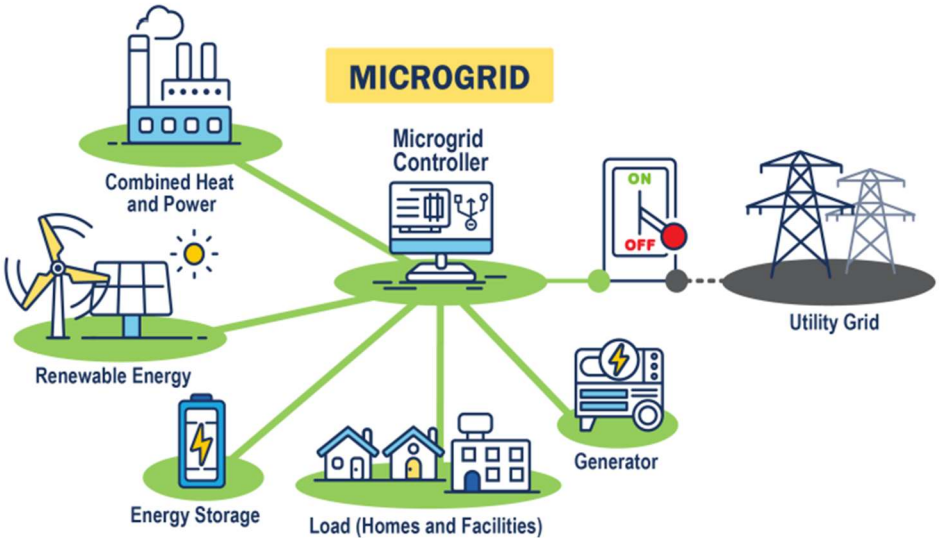


Figure 1 Components of a microgrid (US DOE 2024).

Microgrid use is growing. The majority of installed microgrids rely on conventional fuels, making up 80 percent of installed capacity (NARUC 2023), with natural gas predominating. However, microgrids incorporating renewable technologies like solar and battery storage are a significant proportion of installations.

In California, renewable microgrids are about twice as common compared to nationwide installations, with renewable technology microgrids accounting for 63% of installations since 2017, with nearly 50% omitting either diesel or natural gas generation, relying fully on renewable technologies (US DOE 2025). Factors affecting renewable technology adoption include public policies and financial incentives, as well as declining costs and increasing value streams available with renewable systems. Clean energy microgrid benefits include resilience, cost savings, grid services, and non-energy attributes, such as reduced emissions.

A variety of factors influence microgrid desirability and characteristics, including:

- Primary purpose (e.g., reliability, energy independence, economics, resiliency, wildfire management).
- The facilities to be served by the microgrid, their demands, and how facility services might shift during grid outages (e.g., typical day-to-day roles, as well as those catalyzed by outages, such as operating as resilience centers).
- Regulatory, technical, and financial aspects.

The most straightforward path for a microgrid is to provide BtM power to a single facility. A BtM installation is situated on the facility's side of the electric meter, governed by utility rules for connecting and operating a microgrid by a single customer. In contrast, a front-of-meter installation is linked directly to the electric grid and can provide service to it or to multiple customers. Current laws and regulations significantly constrain opportunities for such systems. As a result, front-of-meter systems are not common in California and generally require utility participation, whereas BtM systems can be more readily installed.

Microgrids incorporating renewable energy technologies can provide significant day-to-day value, particularly in facilities with high electricity consumption. While conventional generation technologies can provide additional resilience capacity, they operate as BUGs and cannot provide continuous value beyond resilience.

Microgrids can be part of a community resilience strategy, planned as part of climate adaptation goals. In this context, local governments might first undertake a high-level resilience analysis of their facilities and communities to select specific sites and resilience solutions. Decision and analysis frameworks can support this process. For instance, the U.S. Department of Energy's Designing Resilient Communities identifies four steps that address resilience drivers and selection of alternatives (Jeffers RF et al 2023). Similarly, WRCOG's Energy Resilience Plan utilizes a prioritization matrix to assist with selecting facilities for microgrids based on climate hazards, social vulnerabilities, a building's characteristics and power system. Such frameworks can identify a range of resilience issues and actions, leading to identification of microgrids as a resilience solution along with the sites they could benefit.

Legal and regulatory aspects

A variety of laws and regulations influence microgrid deployment, operation, value, and capabilities. Under the overall aegis of California Public Utilities Commission (CPUC) regulation,[2] each investor-owned utility (IOU) maintains their own microgrid rules and tariffs. Utilities manage and approve any interconnection of a microgrid to their systems. Their electric rates and opportunities for participation in grid services affect the financial value of customer-sited energy systems.

There are several types of utilities in California, each regulated under different regimes. These include IOUs, cooperatives, public utility districts, and water agencies. The CPUC directly regulates IOUs, the largest of which are Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). Municipal utilities, such as Los Angeles Department of Water and Power (LADWP), Riverside Public Utilities, Banning Electric Utility, Moreno Valley Utilities, and Corona Department of Water & Power, are not under CPUC authority; the cities they service are regulated by locally elected governing boards. Non-IOU energy service providers generally have more local autonomy and are subject to different governance and operating models. As a result, the issues and constraints affecting microgrids in IOU service territories are different from those sited within municipal lands.

Community Choice Aggregators (CCAs) are not utilities but purchase and provide generation over the incumbent IOU's infrastructure. CCAs offer distinct generation rates and may be involved in developing local programs, such as for microgrids and virtual power plants (VPP), a network of distributed energy resources (DER), like solar panels, batteries, and electric vehicle (EV) chargers, that are controlled and coordinated to function as a single, larger generator.

The regulatory regime under which microgrids operate affects considerations of where they can be installed, how they are allowed to operate, and what value they can provide.

[2] The Public Utility Code is the primary policy vehicle under which California electric utilities are governed.

Additional rules and design practices, such as electrical system codes and fire safety regulations, also influence microgrid characteristics. For instance, renewable energy and battery storage systems have specific requirements to ensure their safe operation and protection from fires.

Regulatory constraints on microgrid deployment in IOU territories effectively limit their use to a single metered property and constrain their total generating capacity. Public Utilities Code rule 218b, the "over-the-fence" decree, specifies that only an electric corporation can provide electricity to multiple properties, with limited exceptions. This requirement effectively makes it infeasible to provide microgrid services to numerous properties in territories regulated by the code. Additional rules, including Public Utilities Code Section 2827(c)(1) and related Net Energy Metering tariffs, limit the amount of energy that can be generated on a property to that property's annual consumption.

Though Rule 218b, and the CPUC's interpretation thereof, effectively prohibits multi-customer microgrids that are not utility-operated, there are limited opportunities to share financial value among facilities within IOU territory:

- The Net Billing Aggregation Sub tariff allows credits for generation to be shared among properties adjacent to a generator. This tariff enables excess power production from one facility to be credited against electric charges for a neighboring facility.
- Virtual Net Energy Billing (VNBT) empowers an owner of a multi-tenant property to allocate a renewable electrical generation facility's benefits to tenants across multiple units.
- The Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT) allows local and tribal governments and universities to share generation credits from a system located on one government-owned property with billing accounts at other government-owned properties. System size under RES-BCT is limited to five megawatts (MW), and bill credits are applied at the generation-only portion of a customer's retail rate.
- Customer facilities can also directly receive compensation for Renewable Energy Credits (RECs), though certification requirements may make this impractical for smaller generators. (CPUC 2025b).
- Microgrid advocates have pointed to possible over-the-fence workarounds, including organizing local energy systems under a homeowners' association structure; deploying them as part of greenfield developments; and detaching payments from direct energy services (e.g., parking fees for electric vehicle recharging).

In 2018 the California Legislature passed Senate Bill (SB) 1339, with the goal of facilitating microgrid commercialization. In 2021, the CPUC authorized the $200 million Microgrid Incentive Program (MIP), of which $83.3 million was allocated to SCE, $17.5 million for SDG&E, the remainder to PG&E. MIP projects can receive up to $15 million. MIP microgrids would be utility-operated and would not provide value to customers other than resiliency (Cohn L 2024).

The IOUs are working with the CPUC to further develop this program, including creating multi-property microgrid operating agreements and related rules and procedures. (CPUC 2025, SCE 2025). The program allows microgrids to serve multiple properties, but unlike behind-the-

meter systems, constraints on their operation, particularly during grid-connected conditions, limit the economic value.

In March 2025, PG&E selected nine community-driven microgrids for up to $43 million in grant funding, located in Humboldt, Lake, and Marin counties, with four serving tribal communities. PG&E opened a second funding application window in April 2025.

SCE's MIP handbook outlines participation requirements, including eligibility and project lifecycle across five project stages: consultation, application, studies, contracting and development, and operations (SCE 2025).

Each IOU has a Rule 21 tariff, which specifies the process for interconnecting generating facilities to the grid, including renewable systems and microgrids. The IOU must approve connections, as well as how a microgrid connects and disconnects. Interconnection issues can significantly impact microgrid projects. There may be delays associated with utility review and project compliance.

In 2023, California passed SB 410, which directed the CPUC to establish average and target time periods for establishing grid connections and upgrades. In 2024, the CPUC established energization targets and timelines for the three IOUs (CPUC 2024a), and issued an order for Limited Generation Profiles (LGP), designed to minimize a renewable energy project's grid impacts and avoid infrastructure upgrades that could prevent a project from advancing (CPUC 2024b, IREC 2024). LGPs specify the amount of power a facility can export to the grid at various times during the year, allowing a project to be sized to maximize its benefits while staying within grid constraints.

Conventional generation resources can bolster reliability, but their operation is generally limited to emergencies. The California Air Resource Board (CARB) regulates emissions from BUGs and constrains their use to periods of power loss or energy crisis. Backup generators must be tested periodically for compliance with emission and safety regulations and operational readiness, including under NFPA 110 and local air district rules (CARB 2025, Duthie Power 2020, NFPA 2025, South Coast Air Quality Management District 2025). BUGs do not offer additional value associated with reducing grid purchases, rate arbitrage or participating in demand response (DR) programs.

Technical aspects

Different production, storage, and management components can be incorporated into a microgrid to maximize resiliency and economic value. Renewable energy systems, especially those relying on solar generation and battery storage, offer significant benefits, with the ability to operate continuously during grid-connected conditions. For instance, local solar generation can directly reduce retail grid purchases. Energy storage systems can be charged during the day to power a facility at night, while also enabling it to shift energy consumption to times when rates are cheaper. Additional value can be derived from participation in programs like DR and VPP. Renewables can also help address local government or Tribal clean energy and emissions objectives, supporting achievement of Climate Action and Adaptation Plans.

Conventional power sources, like fossil gas, diesel generators or combined heat and power systems, can provide power independently or as backups when solar generation or battery storage capacity is insufficient. These conventional technologies, though, require a steady fuel supply, which may be interrupted during a disaster. In addition, they need regular testing to ensure they can operate during a grid outage. Since 2000, 57% of microgrids installed in California incorporate solar or wind; 44% exclude any diesel or gas generation (US DOE 2025).

A microgrid will have a DER management system. Critical loads that must be powered during a grid outage may be isolated from ordinary loads with separately energized circuits. Load management can be integrated alongside the microgrid controller to shed and adjust loads during islanded operation. A microgrid will feature interconnect devices, which allow it to safely connect and disconnect from the bulk grid, maintain a local electric grid when grid-disconnected, and ensure supply to critical loads.

A site will typically have a diversity of electric loads, which can be adjusted to optimize resilience, economic value, and energy services provision. Loads might include HVAC or EV charging, which have significant flexibility as to when and how much they operate. Building energy management systems and EV charge controllers can be integrated into a microgrid's control system. During islanded operations, flexible loads can be reduced when power is scarce, extending resiliency, or increased when more supply is available for cooling or vehicle charging. Like energy storage systems, these flexible loads can be managed during grid-connected operations to maximize the energy system's economic value by enabling capabilities such as load shifting, peak shaving, tariff arbitrage, and DR program participation.

Microgrid components must work correctly together to ensure that power quality is maintained. Facility systems and equipment will only operate within a range of power quality factors. While microgrid components may have been certified for individual operation, they must also be evaluated as a system. During island mode, hazardous conditions, such as possible power back feeding, must be considered and addressed from the design phase through commissioning and operations.

Various vendors and approaches are available to design microgrids. Sandia Labs provides a high-level conceptual method of microgrid design (Broderick R et al 2022) in two phases. Foundational design elements consist of safety, security, reliability, sustainability, and cost-effectiveness. In phase 1, system boundaries are defined, stakeholders identified, critical loads enumerated, threats identified – such as natural disasters – and policy constraints captured. In phase 2, possible solutions are formulated and analyzed to determine whether they meet phase 1 objectives.

National Association of Regulatory Utility Commissioners (NARUC) offers a different overview of microgrid design, starting with preliminary considerations to final interconnection (NARUC 2021b). Initial design questions include the desired fuel mix, value stacking opportunities, and operating modes. This is followed by designation of critical loads and energy efficiency options; assessment of multifacility-specific aspects, where allowed; selection of

generation and storage resources; cost evaluation; hardware selection including software, inverters, communication, and controls; and grid interconnection.

Microgrids are a potential element in a facility-specific energy strategy, which may include energy efficiency to reduce consumption, onsite generation and storage that provide local energy services, and load control to reshape building loads and provide grid services. Reducing energy consumption can lower energy bills and lessen the system size needed to provide resilience, thus reducing costs. During islanded operations, while providing power to the facility, a microgrid can also serve as a resilience center, offering services to the community or other entities.

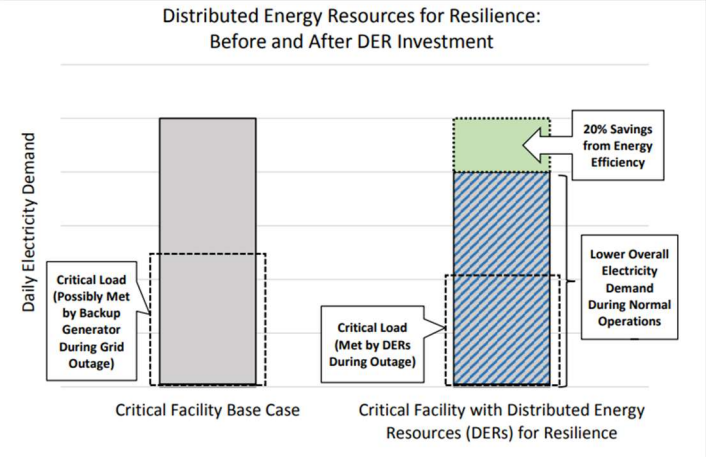


Figure 2 Electricity usage before and after DER investment. (US DOE 2019.)

Financial and Non-Financial Aspects

Microgrids can serve to reduce electric bills, earn revenue for grid services and exported power, and increase resiliency. Many factors influence microgrid economics, including upfront and operating expenses, energy costs, resiliency value, and the types of services the microgrid can provide. In addition, microgrids span a range of sizes and capabilities: small systems serving individual facilities, those incorporating a mix of generating technologies, large campus and community-wide systems.

Costs are influenced by project attributes, as well as fragmented markets, supply chain challenges and variable contracting terms, which can increase costs for project developers. Limited local government staff resources and expertise can hamper microgrid deployment. Grouping multiple projects together and creating streamlined procurement, financing, and contracting terms could lower overall costs.

California offers several microgrid incentive and funding programs (see, e.g., CalOES 2023), including:

- Microgrid Incentive Program provides limited funding to local and tribal governments, administered through the investor-owned utilities, for certain microgrids.
- California Infrastructure State Revolving Fund (ISRF) offers low-cost direct loans to local governments and nonprofits sponsored by public agencies.
- California Lending for Energy & Environmental Needs (CLEEN) provides loans to projects to help meet the state's greenhouse gas reduction, water conservation, and environmental preservation goals.
- The California Energy Commission (CEC) offers funding opportunities, some of which may be available for microgrid projects (see https://www.energy.ca.gov/funding-opportunities/solicitations).
- Utilities offer incentives, including, for instance, credits or rebates for equipment and payments for demand response capacity.

Collaborations with other entities, such as CCAs, can facilitate creation of streamlined microgrid programs. For example, Ava Community Energy – formerly East Bay Community Energy – which serves Alameda County and part of San Joaquin County, developed a streamlined microgrid program for participating jurisdictions (Wood E 2023). The CCA studied hundreds of critical facilities for hazard exposure, community service, and renewable energy potential, identifying sites suitable for microgrid deployment. It then developed a standard power purchase agreement, which participating cities would commit to in advance of deploying projects. This created a portfolio of projects with standardized terms that developers were more incentivized to bid on, as compared to one-off projects. Through public solicitation, Ava selected Gridscape as the project developer and Sunwealth as the investment firm. As part of the program, Sunwealth signed a single power purchase agreement with Ava, which then facilitated all 30 projects planned for the first phase of the program.

Renewable energy systems and microgrids can unlock a range of value streams during grid-connected operation. Value stacking creates revenue streams associated with electric bills savings from reduced consumption and peak demand; shifting energy use to times when it is less costly through energy arbitrage; participation in DR and aggregation programs; sale of excess energy; and provision of grid services. The value that can be achieved through each of these operating capabilities depends on utility rates, participation rules, and programs.

Emergency Load Reduction Program (ELRP) pays $2/kWh during certain load reduction events (CPUC 2025x, SCE 2025x). The ELRP pilot runs through 2027.
CPUC 2025x, Emergency Load Reduction Program, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/emergency-load-reduction-program
SCEC 2025x, Emergency Load Reduction Program (ELRP) FAQs, https://www.sce.com/factsheet/elrp_faq

Under DR programs, facilities adjust their energy use on a stipulated number of occasions, such as during extreme heat events that place significant strain on the power grid. DR programs are administered by utilities and the California Independent System Operator (CAISO); participation may be direct or through aggregators that enable entities with different capabilities or lower load reduction capacity to participate. VPPs are offered through third-party companies, which aggregate load from multiple sites and provide payments when they adjust their demand in

response to grid signals. Excess energy can also be sold back to the utility, though this currently provides lower value than other opportunities, as payments vary by hour and are much lower than retail electricity rates. These programs can provide both upfront enrollment incentives, as well as ongoing participation payments. Large energy storage systems may also be eligible to participate in additional grid support services.

Value streams can be significant. For instance, a behind-the-meter commercial-scale photovoltaic plus storage system providing 0.5-megawatt storage, one MW generation, and four hours of energy storage in PG&E's territory could offer nearly $400/MWh just from bill savings, demand response participation, and local incentive payments (Lazard 2025).

NREL researchers modeled the value of conventional diesel as compared with renewable energy solar plus battery storage microgrids in SCE territory (Marqusee J et al 2021). The renewable microgrid consisted of 8.2 MW solar plus a 4.3 MW / 12.9 MWh storage system. Pre-microgrid life-cycle costs were $142 million; costs with a diesel microgrid $154 million; while costs for a renewable-energy microgrid were $142 million; comparable to costs without a microgrid. The net-present cost with the diesel microgrid was $12 million, but -0.2 million with the renewable microgrid. That is, the renewable microgrid provided a slightly positive value, significant savings compared with the diesel microgrid option.

A real-world example is provided by Direct Relief's microgrid, also in SCE territory. The system consists of a 320-kW solar array, 676 kWh battery storage, and 600 kW diesel generator. Following a year of operation, it incurred a blended premium from the microgrid power purchase agreement along with electricity purchases from SCE of $0.0056/kWh, or about a 3% increase in electricity costs. This premium was paid to ensure resilience of critical infrastructure while offsetting about 57% of grid electricity usage (Clean Coalition 2025).

These examples illustrate potential value from a renewable energy microgrid; actual worth depends on a variety of factors. For instance, since the NREL and Direct Relief case studies up-front equipment costs have declined due to technological advancements but increased because of changes to government policies (e.g., tax code and tariff changes). Simultaneously, electricity rates have risen. Site load characteristics, operation of a renewable energy system, and the programs it participates in all affect its economics.

Ownership and operating models impact microgrid economic value, including up-front costs, financing and operating costs, as influenced by available programs and incentives. There are a variety of possible models, including:

- Individual or direct ownership. In this model, the facility owner also owns the renewable energy systems and microgrid and typically contracts with service providers for maintenance and operating support, such as battery scheduling or participation in programs like virtual power plants. This option allows the owner to capture the largest share of value but also requires them to raise capital and take responsibility for maintenance and operation. It also affects the forms of capital and incentives available to finance the system. For instance, a local government may be able to access low-cost

financing but not have access to some tax benefits. If financing is constrained, a local government may want to consider alternatives, such as third-party ownership (see below).

- Third party ownership (TPO). A service provider installs, owns, and operates the system. The facility operator/owner purchases power from the third-party, typically through a power purchase agreement (PPA), which enables the power user (purchaser) to pay a pre-negotiated electricity price. System construction and operating costs are covered by the third party, which recoups its expenses over time from electricity sales and other revenue streams. In this model the facility owner (e.g., local government) does not have to pay for the system directly. It offloads operating and financing responsibility to the TPO, but at a cost of some of the financial value and flexibility otherwise available from the system.

- Energy services agreements (ESAs) are similar to third-party ownership, except additional services may be provided beyond energy sales. For instance, an ESA could include implementing energy efficiency measures at contracted facilities.

- Utility ownership and/or control. The utility owns and operates the system, more common for front-of-meter systems. In the case of microgrids, the facility (or facilities) benefit from increased resilience, but do not reap day-to-day operational value. For instance, under MIP the microgrid is managed by the utility while customers continue to pay regular retail rates. This significantly reduces the value available from the system to primarily resilience.

The technology and policy landscapes that impact system economics are subject to rapid change. Battery storage has seen dramatic cost declines in recent years, significantly altering its economics, promoting increases in installed storage capacity. Solar and wind have also seen significant price declines. At the same time, supply-chain issues can lead to delays for power equipment, including generators and transformers.

Recent federal law changes eliminate renewable generation technology credits by 2027. Energy storage credits will be maintained until 2033, after which it phases down until it is eliminated in 2036. Projects beginning construction after December 31, 2025, will be subject to Prohibited Foreign Entities restrictions; the impact on specific developments will depend in part on the sources of project components. (Nowak BJ and Delano PJ 2025).

While policy and incentive changes will raise renewable energy project costs, they do not necessarily make them uneconomical. Retail energy costs in California are high and projected to keep rising; local renewable energy projects and microgrids may remain economical even with the loss of former tax value.

Avoiding power losses to critical facilities can have significant financial and nonfinancial benefits. A distributed energy system provides day-to-day operational value, while a microgrid provides resilience value while incorporating other energy systems. Estimating the value of resilience can help to assess a microgrid's worth, beyond the day-to-day operational value of local energy systems.

The resilience value can be significant. Determining a monetary value for resilience can be complex, necessitating an understanding of the likelihood of power interruptions, associated potential lost value, as well as the worth that can be provided by a microgrid during islanded operation. While no single method exists to value resilience, several publicly available approaches and tools have been developed. These include the US Department of Energy's Interruption Cost Estimate (ICE) Calculator, which provides estimates and calculations of the costs of power loss; NREL's Customer Damage Function (CDF) calculator to estimate losses to specific facilities; a Social Burden Method which considers communal burden inconveniences; the Power Outage Economics Tool (POET) to estimate the cost of long-duration outages; Federal Emergency Management Administration's Benefit-Cost Analysis Toolkit, which provides values for lost emergency services; as well as Sandia National Labs Resiliency Node Cluster Analysis Tool (ReNCAT). Valuing resilience is further complicated when considering long duration outages, the societal costs of widespread outages, and the increasing quantity of services, such as electric vehicles, that can be supported by resilient energy systems. (See Rickerson W et al 2022.)

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Western Riverside Council of Governments Joint Meeting of the WRCOG Executive Committee and Supporting Foundation Board of Directors

Staff Report

Subject: Western Riverside County Clean Cities Coalition Activities Update

Contact: Taylor York, Program Manager, tyork@wrcog.us, (951) 405-6751

Date: May 4, 2026

Recommended Action(s):

1. Receive and file.

Summary:

The Western Riverside County Clean Cities Coalition is implementing over $3M in State-funded projects to help members navigate clean vehicle policies, deploy zero-emission vehicles and infrastructure, train fleet technicians, and build partnerships that support community goals.

Purpose / WRCOG 2022-2027 Strategic Plan Goal:

The purpose of this item is to provide an update on the activities of the Western Riverside County Clean Cities Coalition. This item is aligned with WRCOG's 2022-2027 Strategic Plan Goal #5 (Develop projects and programs that improve infrastructure and sustainable development in our subregion).

Discussion:

Background

The Western Riverside County Clean Cities Coalition was established as a WRCOG Program in 1997 and is part of a national network (https://cleancities.energy.gov/) of approximately 75 Coalitions supported by the U.S. Department of Energy. The Coalition brings together local government and private industries to expand the use of alternatives to petroleum fuel and promote education and technical assistance in support of advanced technologies in transportation. Coalition activities and those of its stakeholders also help municipalities manage the expanding use of Alternative Fuel Vehicles (AFV) in the subregion while promoting resources that strengthen AFV infrastructure. Coalition stakeholders include public and private fleets, local and state agencies, fuel providers, technology manufacturers, local educational institutions, and more.

Activities from Coalition stakeholders reduce millions of gallons of petroleum fuel use and thousands of

tons of greenhouse gas emissions each year. This is achieved through adopting fleet vehicles, deploying AFV fueling and charging infrastructure, and acquiring funding from state, federal, and local programs.

Present Situation

Coalition Funding Update: Coalition funding through the U.S. Department of Energy has been restored following a period of uncertainty in federal grant activity over the past year, during which federal coalition funding was not available, and the traditional funding cycle was disrupted.

A new coalition cooperative agreement has now been issued, initiating a new five-year grant cycle with agreements to be issued annually. The cooperative agreement structure provides a task-based scope of work for coalitions, allowing for greater flexibility and alignment with evolving program priorities while continuing to support regional coordination, technical assistance, and project development.

Funding for this year has increased slightly to $138,000 compared to the previous Cooperative Agreements funding of $116,000.

Western Riverside Municipal Green Zones: In 2025, WRCOG launched a $1.35M grant-funded initiative to accelerate the deployment of zero-emission vehicles (ZEVs) and charging infrastructure. The project is being carried out in partnership with the Cities of Banning and Moreno Valley, Riverside County Purchasing and Fleet Services, and the Riverside County Transportation and Land Management Agency, with funding provided through the California Air Resources Board (CARB) and California Energy Commission's (CEC) Sustainable Heavy-Duty Initiatives for Future Technology (SHIFT) Program.

The project continues to make significant progress, with most vehicles now deployed. Recent deployments include two Rivian electric vehicles, three Ford F-150 Lightning pickup trucks, a Toyota BZ4X, and one Rizon electric dump truck, along with the charging infrastructure necessary to support operations.

To support safe and effective fleet adoption, WRCOG conducted a multi-day technician training February 24–26 and March 3–4, 2026, training 12 technicians from partner agencies. The training focused on increasing technical knowledge of electric vehicles and improving safety practices when servicing and maintaining ZEVs.

Project activities will continue to focus on community engagement, data collection, and documentation of best practices, which will be incorporated into a comprehensive ZEV Deployment Toolkit to support future deployments across the region.

Clean Mobility Options Program: Through the Clean Mobility Options Program (https://cleanmobilityoptions.org), WRCOG was awarded a $1.8M grant to launch a zero-emission community car-share program across the subregion. The project will deploy 15 vehicles at sites located in multiple WRCOG member jurisdictions.

Project partner and mobility operator Electric Vehicle Get In Drive Everywhere (EVGIDE) will own and operate the fleet. The initiative also includes development of a mobility-as-a-service platform that will connect regional transit and mobility options in a single, user-friendly system. To ensure long-term sustainability and direct benefits to disadvantaged communities, WRCOG will lead robust engagement

with community members, municipalities, and stakeholders.

The project is currently in the final stages of the planning phase. WRCOG staff are working with member agencies - including the Cities of Corona, Hemet, and Moreno Valley - to finalize suitable deployment sites. Next steps are focused on finalizing locations, completing development of the supporting application software, and installing signage and striping at designated parking spaces.

The EVGIDE project continues to advance, with vehicle deployments anticipated to begin in June. WRCOG and EVGIDE are currently conducting community outreach to raise awareness of the program and encourage participation, with a focus on ensuring accessibility and benefits to priority communities.

Zero-Emission Vehicle Network: The Coalition facilitates the Inland ZEV Network to help members navigate State ZEV policies and deploy ZEVs into their fleets. In partnership with the Southern California Clean Cities Coalition, hosted by the Southern California Association of Governments, WRCOG continues to grow this effort with the goal of expanding a regional resource for the entire Inland Empire.

The Network provides a forum for information sharing, partnership-building, and collaborative problem-solving. Its purpose is to expand knowledge of ZEV technologies, support fleet adoption, and help participants navigate the policies driving California's clean transportation transition. Participants include local agencies, utilities, public and private fleets, regulators, educational institutions, manufacturers, fuel providers, and community partners.

Planning is currently underway for the 2nd Annual Inland Zero Emission Vehicle Network Expo, which will take place on August 27, 2026, at the Riverside Convention Center. Building on the success of the inaugural event, the Expo will continue to provide a forum for regional collaboration, technical training, and industry engagement to support ZEV deployment across the Inland Empire. Nearly 150 attendees participated last year, including fleet operators, industry representatives, educators, utilities, vehicle manufacturers, and community groups. The event features a state and regional policy forum, along with workshops on vehicle and infrastructure deployment, workforce development and training, project and grant funding, compliance and regulations, and much more. An expo showcases ZEVs ranging from light-duty car-share vehicles to heavy-duty electric dump trucks and box trucks.

The Network also convenes regularly through meetings, site visits, and tours of ZEV fueling, charging, and manufacturing facilities—offering members hands-on exposure to new technologies that can advance their fleet goals. The next regular Network meeting will be held virtually on May 13, 2026, at 1:00 p.m. WRCOG Clean Cities member jurisdictions continue to play a key role in this effort.

For information on how to participate in the Network, please contact Taylor York at tyork@wrcog.us.

Prior Action(s):

None.

Financial Summary:

This item is for informational purposes only; therefore, there is no fiscal impact. All activities as part of the Western Riverside County Clean Cities Coalition are budgeted under the Clean Cities Program budget (Fund 120), which is funded by member agencies, the Department of Energy Clean Cities

Cooperative Agreement, and other periodic grant funding.

Attachment(s):

None.

Western Riverside Council of Governments Joint Meeting of the WRCOG Executive Committee and Supporting Foundation Board of Directors

Staff Report

Subject: Regional Food Rescue Program Activities Update

Contact: Dr. Olivia Sanchez, Program Manager, osanchez@wrcog.us, (951) 405-6721

Date: May 4, 2026

Recommended Action(s):

1. Receive and file.

Summary:

Senate Bill (SB) 1383, Organics Waste Reduction (OWR), requires local jurisdictions to reduce organic waste disposal and implement edible food recovery programs, placing greater emphasis on local government compliance, monitoring, and enforcement. This update reflects WRCOG's Regional Food Rescue Program as it moves into year three, serving the current participants, which include the Cities of Jurupa Valley, Murrieta, and Perris, through a regional approach that educates commercial edible food generators, expands access to food recovery organizations, conducts inspections, and documents compliance through a centralized platform. As the Program continues, participating jurisdictions will maintain annual inspections and ongoing education to support sustained compliance with SB 1383 requirements.

Purpose / WRCOG 2022-2027 Strategic Plan Goal:

The purpose of this item is to provide an overview of the Regional Food Rescue Program. This effort aligns with WRCOG's 2022-2027 Strategic Plan Goal #6 (Develop and implement programs that support resilience for our region) and sub-goal #6.3 (Continuing to support the Solid Waste and Recycling Program).

Discussion:

Background

California's SB 1383 mandates a 50% reduction in organic waste disposal from 2014 levels by 2020 and a 75% reduction by 2025, as well as recovering 20% of edible food for human consumption by 2025. To comply with these requirements, WRCOG, in collaboration with MSW Consultants, developed the Regional Food Rescue Program, which involves multiple cities. Site visits and inspections were

conducted, resulting in food donations. Moving forward, cities must enforce Program requirements and penalties through annual inspections and ongoing education to ensure continued compliance with SB 1383.

WRCOG's Program was developed and implemented to assist its member agencies in meeting SB 1383's requirements for edible food recovery. This Program aims to educate commercial edible food generators (CEFGs) about their food donation obligations, increase access to food recovery organizations (FROs), monitor compliance, and identify gaps in food recovery capacity.

The Program included the previous participating Cities of Jurupa Valley, Moreno Valley, Murrieta, Perris, and San Jacinto. The team leading this effort included WRCOG staff, MSW Consultants, DeGrave Communications, and Mariposa Eco Consulting. The online platform and database, Careit, documented rescue efforts, recorded tons of food donations, and documented inspections for both the CEFGs and the FROs.

Present Situation

During year one of the Program, foundational outreach and education efforts were prioritized to build awareness and drive participation among CEFGs and FROs. Initial inventories were developed, partnerships were established, and entities were onboarded to support compliance with SB 1383. A multilingual outreach campaign was developed and supported through workshops, social media, newsletters, and coordinated education with the Riverside County Department of Environmental Health.

In year two, the Program shifted from outreach to a stronger focus on compliance. CEFG and FRO inventories were refined using improved data on business operations and square footage, yielding more accurate inspection lists and implementation records. Inspections were conducted in the then five participating Cities of Jurupa Valley, Moreno Valley, Murrieta, Perris, and San Jacinto. Results showed strong overall compliance, with 86% of CEFGs and 95% of FROs meeting SB 1383 food recovery requirements. Jurisdictions initiated early-stage enforcement for non-compliant entities, with plans for follow-up inspections and, if necessary, the issuance of formal Notices of Violation.

The Program is anchored by the Careit platform, which serves as a centralized tool for matching food donors and recovery organizations, tracking donations, managing records, and generating reports. Use of Careit has enabled participating jurisdictions to meet multiple SB 1383 requirements, including outreach documentation, inspection tracking, compliance monitoring, and complaint management, while also allowing WRCOG to monitor Program performance at a regional level.

Over the past three years, from September 2023 to the present, the Program has achieved significant, measurable outcomes. A total of 18,846,522.7 pounds of food were recovered through 16,257 donations, resulting in an estimated 25,925.04 tons of carbon dioxide emissions avoided. These metrics demonstrate the Program's substantial environmental and resource conservation benefits, in addition to its core objective of increasing food recovery and supporting community needs.

Year three focuses on maintaining compliance and improving Program accessibility and consistency. This includes developing onboarding videos for CEFGs and FROs to provide clear, standardized guidance on program requirements, thereby supporting continued compliance and reducing administrative burden.

The Program is expected to sunset in June of 2026, as local jurisdictions have primarily relied on SB 1383 grant funding to implement edible food recovery and food rescue programs. These funds must be fully expended by November 2026, and no additional OWR funding allocations are anticipated. As a result, jurisdictions are encouraged to proactively plan for long-term Program sustainability by identifying strategies to absorb ongoing costs or secure alternative funding to continue SB 1383 compliance activities, including edible food recovery and food rescue programming.

Prior Action(s):

None.

Financial Summary:

Activities related to SB 1383 are included in the Agency's adopted budget for Fiscal Year 2025/2026 under the Solid Waste Fund (130).

Attachment(s):

None.

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COVER PAGE
MEMORANDUM OF UNDERSTANDING
AMENDMENT NO. 1
No. M-018-25

SCAG Overall Work Program (OWP) No: 305-4927.04

MOU No: M-018-25
MOU Execution Date: February 19, 2025
Agency Contact: Christopher Tzeng (ctzeng@wrcog.us)

Sub-Recipient Name: Western Riverside Council of Governments
Sub-Recipient's UEI No: C589CLZSR4J7
MOU Amount: $1,402,933.58

Subaward Period of Performance Start Date: See Section 37
Subaward Period of Performance End Date: June 30, 2026

Type of Contract: Project Specific
Method of Payment: See Section 6 of this MOU

Project Title: Western Riverside Council of Governments REAP 2.0 Subregional Partnership 2.0 Program Grant

Project Description: Western Riverside Council of Governments will utilize REAP 2.0 funding for eligible uses and activities as provided in the Subregional Partnership Program Guidelines.

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AMENDMENT NO. 1
TO
MEMORANDUM OF UNDERSTANDING
No. M-018-25

BETWEEN THE
SOUTHERN CALIFORNIA ASSOCIATION OF GOVERNMENTS AND
WESTERN RIVERSIDE COUNCIL OF GOVERNMENTS FOR
REAP 2.0 SUBREGIONAL PARTNERSHIP 2.0 PROGRAM GRANT

(SCAG Project/OWP No. 305-4927.04)

This Amendment No. 1 ("Amendment") to the underlying Memorandum of Understanding No. (M-018-25) ("MOU") is by and between the **SOUTHERN CALIFORNIA ASSOCIATION OF GOVERNMENTS** ("SCAG") and **WESTERN RIVERSIDE COUNCIL OF GOVERNMENTS** ("WRCOG"), subsequently herein referred to as the "Sub-Recipient," for a Subregional Partnership ("SRP") 2.0 Program Grant. SCAG and the Sub-Recipient are individually referred to herein as "Party" and may be collectively referred to herein as "Parties."

RECITALS

WHEREAS, the Parties entered into the MOU dated February 19, 2025; and

WHEREAS, Section 11 of the MOU permits the Parties to amend the MOU through written amendment; and

WHEREAS, the purpose of Amendment 1 is to amend Section 4 (Project Management): the SCAG Project Manager and Section 5 (Funding) to reflect funds directed to the Riverside County Revolving Loan Fund and funds returned to SCAG.

NOW THEREFORE, IT IS MUTUALLY AGREED THAT:

1. Section 4 (Project Management) subsection (c) is amended to read:

   b. For purposes of this MOU, Sub-Recipient designates the following individual(s) as its Project Manager:

   Kaitlin McCafferty
   Associate Regional Planner
   (213) 630-1538
   Mccafferty@scag.ca.gov

   Sub-Recipient reserves the right to change this designation upon written notice to SCAG.

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2. **Section 5 (Funding) sub-section (a) is amended to read:**

   a. SCAG's contribution to the Projects is funded wholly with REAP 2.0 funds, in an amount not to exceed $1,402,933.58 ("Grant Funds"). The individual Projects shall be funded as follows ("Project Funds"):

      Housing Technical Assistance – $1,402,933.58

      Pursuant to WRCOG Executive Committee action, Sub-Recipient requested that $200,000 in grant funds (from the initial award of $1,629,834.00) is to be redirected to the County of Riverside, Riverside County Revolving Loan Fund and $26,900.42 in unallocated grant funds is to be returned to SCAG for reprogramming.

[Signatures on Following Page]

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SIGNATURE PAGE TO
AMENDMENT NO. 1
TO
MEMORANDUM OF UNDERSTANDING
NO. M-018-25

IN WITNESS WHEREOF, the Parties have caused this Amendment No. 1 to be executed by their duly authorized representatives as of the dates indicated below:

SOUTHERN CALIFORNIA ASSOCIATION OF GOVERNMENTS ("SCAG")

DocuSigned by:
By: Cindy Giraldo 00E46B3F0E8F43F...
Cindy Giraldo
Chief Financial Officer

4/20/2026
Date

APPROVED AS TO FORM:

DocuSigned by:
By: Richard Lam D5866DAB132A453...
Richard Lam
Senior Deputy Legal Counsel

4/20/2026
Date

WESTERN RIVERSIDE COUNCIL OF GOVERNMENTS ("Sub-Recipient")

DocuSigned by:
By: Christopher J. Gray 1C62143FCB06496...
Christopher Gray
Interim Executive Director

4/20/2026
Date

APPROVED AS TO FORM:

DocuSigned by:
By: E54DE3F1B3634C0...
Steven DeBaun
General Counsel

4/20/2026
Date