Energy Research and Development Division

FINAL PROJECT REPORT

Lancaster Advanced Energy Community

California Energy Commission

Edmund G. Brown Jr., Governor

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PREFACE

The California Energy Commission's Energy Research and Development Division supports energy research and development programs to spur innovation in energy efficiency, renewable energy and advanced clean generation, energy-related environmental protection, energy transmission and distribution and transportation.

In 2012, the Electric Program Investment Charge (EPIC) was established by the California Public Utilities Commission to fund public investments in research to create and advance new energy solutions, foster regional innovation and bring ideas from the lab to the marketplace. The California Energy Commission and the state's three largest investor-owned utilities – Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company – were selected to administer the EPIC funds and advance novel technologies, tools, and strategies that provide benefits to their electric ratepayers.

The Energy Commission is committed to ensuring public participation in its research and development programs that promote greater reliability, lower costs, and increase safety for the California electric ratepayer and include:

- Providing societal benefits.
- Reducing greenhouse gas emissions in the electricity sector at the lowest possible cost.
- Supporting California's loading order to meet energy needs first with energy efficiency and demand response, next with renewable energy (distributed generation and utility scale), and finally with clean, conventional electricity supply.
- Supporting low-emission vehicles and transportation.
- Providing economic development.
- Using ratepayer funds efficiently.

Lancaster Advanced Energy Community is the final report for the Lancaster Advanced Energy Community Project (Agreement Number EPC-15-069, Solicitation Number GFO-15-312) conducted by Zero Net Energy (ZNE) Alliance. The information from this project contributes to Energy Research and Development Division's EPIC program.

For more information about the Energy Research and Development Division, please visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-327-1551.

ABSTRACT

In 2011, the City of Lancaster set a goal to become the first zero-net-energy city in California. Regulatory and pricing issues, including high upfront costs for renewable resources, burdensome interconnection applications for energy storage, and unproven business models for leading-edge clean energy technologies such as microgrids are significant barriers to advancing energy technologies at the scale Lancaster requires. This project addresses (1) how to make zero-net-energy residential communities possible from a financial and technical perspective, and (2) how to capture the value of distributed energy resources in a standardized and reliable manner to develop scalable business models and attract the financial investment necessary to support widespread use of clean energy resources.

Keywords: community choice aggregations, distributed energy resources, zero net energy, program design, valuation

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Introduction

The State of California has set ambitious goals towards zero-net energy (ZNE) and emissions reduction in the next few decades. In the *2007 California Strategic Plan*, the California Public Utilities Commission set the goal for all new residential construction to be ZNE by 2020, and for all new commercial construction to be ZNE by 2030. Similarly, in the Global Warming Solutions Act (Assembly Bill 32, Nunez, Chapter 488, Statutes of 2006), Governor Edmund G. Brown, Jr. set the goal that California would reduce greenhouse gas emissions to 40 percent below 1990 emissions levels by 2030.

To achieve these goals, California state agencies, local governments, and technology partners are collaborating on innovative solutions to help communities transition to an efficient, low-carbon economy using electricity generated from clean, renewable resources. These communities are investing in clean, resilient, affordable, and locally sourced electricity generation to help their residents and businesses move to zero-net energy.

One such community pursuing advanced energy measures is the City of Lancaster. The City of Lancaster is a charter city in northern Los Angeles County, in the Antelope Valley Region of California's High Desert. Since 2008, Rex Parris has served as the city's mayor and championed Lancaster as a showcase for renewable energy and clean transportation. In 2011, the City of Lancaster set a goal to become the first renewable energy-fueled city, defined as producing or procuring more electricity within city limits from renewable sources than is consumed. The city's goal has set a clear vision for city council, staff, and the public, while an emerging suite of complementary policies and programs is delivering strong economic and environmental benefits to local residents and the community as a whole.

Project Purpose

Despite the strong efforts from leadership of the City of Lancaster, barriers to zero-net energy remained. The Lancaster Advanced Energy Community Project explored scalable solutions to support Lancaster in its transition to zero-net energy and substantially reduced greenhouse gas emissions. In addition to creating immediate impacts within the City of Lancaster, these solutions were designed to be scalable broadly to other communities in California.

In particular, the City of Lancaster faced two hurdles. The city leadership wanted to create a zero-net energy residential subdivision for low-income residents but lacked the experience to configure or optimize the advanced energy system powering the community. The city and their electricity provider, Lancaster Choice Energy, has a mandate to use one percent of peak system load in energy storage. If not done in a way that maximizes the value of energy storage, such use can be extremely costly.

This advanced energy community project addressed both of these hurdles. In addition to supporting the City of Lancaster, the tools created in this project will allow other communities in California to achieve emission reduction goals by using affordable housing zero-net energy microgrids and value-creating distributed energy resource uses.

Project Process

The project team, with key stakeholders from the community of Lancaster, conducted the project. In Lancaster, the local community choice aggregation, Lancaster Choice Energy, was the lead local partner. As the local electricity provider for the City of Lancaster, Lancaster Choice Energy has its finger on the pulse of energy needs of the community. Throughout the project, it provided an invaluable perspective on what programs and technologies would be the best fit for the community. Additionally, they connected the project team to relevant stakeholders, and supported outreach to city officials.

The team also collaborated with the office of the city manager, the city housing authority, and other stakeholders within city government. The office of the city manager provided input as to which programs would be viable to roll out with city support. The city housing authority is managing the low-income ZNE development known as "Avenue I" and worked closely with the project team to ensure the microgrid design developed by the project team would fit Avenue I needs and budget. This close collaboration allowed for frequent feedback from community stakeholders and rapid iterations cycles. Through this collaboration, the project team was able to verify that the solutions being designed would be useable by community agents in real-world applications.

The project team also engaged with other key stakeholders in the community, including Southern California Edison's interconnection group and the Antelope Valley Transit Authority (which is integrating a fleet of 80 E [electric]-buses into their operating fleet). The project team also worked with the Lancaster City Schools (which is developing aggressive plans for energy storage and microgrid installations, in collaboration with Lancaster Choice Energy and the ZNE Alliance).

Six entities comprised the project team:

- **Zero Net Energy Alliance** was the project lead, managed collaboration and city interaction, and drove public/private partnership development.
- **ConSol** developed the policy framework for land-secured financing strategies that will enable residential communities to advance the zero net energy goals.
- **NHA Advisors** also supported the development of the land-secured financing analysis with their extensive experience providing financing expertise to municipalities.
- **Munitrend** created the financial model to forecast potential results of using land-secured finance to help residential communities achieve zero-net energy.
- **Energy Solutions** led the residential zero-net energy microgrid technical framework development as well as the microgrid cost/benefit analysis. Energy Solutions also managed customer and partner outreach for the distributed energy resources program. Distributed energy resources (DER) are small scale decentralized, community-generated energy systems such as rooftop solar photovoltaic (PV) panels, natural gas turbines, battery storage fuel cells or wind turbines, and are connect to the grid
- **Olivine** developed the DER valuation framework and models and supported the distributed energy resource program design.

The project team worked closely with organizations to ensure the project deliverables represented the best aggregate thinking and ensure consistency across key elements of the project.

Project Results

This project advanced two important clean energy developments in the City of Lancaster – a residential microgrid at the Avenue I subdivision, and a distributed energy resource program for the Lancaster "Green District." The Avenue I subdivision is a 75-unit single-family affordable-housing development sponsored by the Lancaster Housing Authority, designed to be zero-net energy with an islanding microgrid. Islanding mode are power plants or systems that operate in isolation from the local electricity distribution network. The Lancaster "Green District" program is an innovative program to use behind-the-meter energy storage at large Lancaster Choice Energy customer facilities, reducing customer demand charges while alleviating system peaks. In addition, the team developed tools that other communities can use to advance their own zero-net energy community goals. These include (but are not limited to) reports and tools addressing:

- Community distributed energy resource valuation frameworks and business models.
- Residential zero-net energy subdivision microgrid technical designs.
- Public/private partnership models to accelerate adoption of distributed energy resource.
- Community distributed energy resource permitting and interconnection.
- Land-secured financing for zero-net energy residential microgrids.

The list of 20 reports and tools created by the AEC project team is included in Appendix A.

For the microgrid work, the project team developed the technical framework and design for the planned Avenue I subdivision in Lancaster. While the framework provided to the City of Lancaster allows the city to choose between a variety of configurations, the cost/benefit analysis completed clearly demonstrated that all-electric homes using flywheels for energy storage allowed the lowest cost community configuration with the greatest emissions reduction impact. Flywheel storage uses kinetic or moving energy such as a spinning rotor or wheel operating in a vacuum to generate electricity. The project team worked with the Lancaster Housing Authority to ensure their building team is equipped to implement the framework. Lancaster Housing Authority and the project team have worked closely with their utilities consultant to ensure that the interconnection request is properly submitted and that architects and designers have the knowledge and expertise to execute the framework correctly.

Due to land availability constraints, it seems unlikely that Lancaster Housing Authority will be able to use flywheels at Avenue I. However, the City of Lancaster is planning to use the technical framework to develop several other zero-net energy residential microgrids within city limits. It is likely that flywheels will be used in other developments with fewer land availability constraints, such as the planned Sierra Highway development with more than 160 homes.

The project team also explored using land-secured financing to fund residential zero-net energy microgrids. While challenges still exist when using land-secured financing with funds for zero-net energy microgrids, the team identified potential paths forward and recommended policy changes for the State of California to further pave the way for using land-secured financing for zero-net energy. In particular, the project team recommended that Senate Bill 555 (Wolk, Chapter 679, Statutes of 2015) be amended to allow the use of community facilities districts to finance the construction of community solar generation on private land when linked to new construction. In addition, the case for using land-secured finance to fund residential zero-net energy construction would be strengthened if the 2019 revision of Title 24 requirements permitted off-site solar (as off-site solar is generally more cost-effective from a community perspective) to fulfill requirements. The financial and technical tools created to develop residential microgrids will be available to other communities, which will enable many more communities to capture the value that zero-net energy residential microgrids can deliver.

Similarly, the team worked with Lancaster Choice Energy to roll out the "Green District" distributed energy resource program. The "Green District" program creates both customer demand charge reduction savings and Lancaster Choice Energy procurement savings from energy storage by targeting customer electricity loads with peaks that occur during Lancaster Choice Energy system peaks. The "Green District" program leveraged work undertaken by the project team to analyze how the value potential of distributed energy resources could be optimized – with a particular focus on solar, energy storage, and energy efficiency. By strategically optimizing the value of the locations, configurations, and use cases of distributed energy resources, communities can rapidly realize the benefits of these installations, and in turn, further use DER installations. After completing initial program design, the project team identified a priority list of potential customers and began outreach to key targets. As a result, the project team and Lancaster Choice Energy have identified two pilot sites that are moving forward with storage. The project team and Lancaster Choice Energy plan to scale the "Green District" program to at least 250 customers during Phase II of the project. While the ease with which community choice aggregators can use on-bill financing may make this program particularly suitable for aggregators, with proper operational practices, a similar program could be used by most types of load-serving entities. Community choice aggregators are an alternative to the investor-owned utility that allows cities and counties to buy or pool their own electricity for residents and businesses within their locales.

The "Green District" program leveraged the DER valuation framework to identify how maximum value can be extracted from energy storage. Valuation framework considers variables like markets, competition, management and assets numerous times to build a reliable financial or "valuing" forecast. The DER valuation framework solved a major challenge in using DERs. Historically, identifying applicable value streams accurately and making direct comparisons between different DER technologies has been, at best, complicated and imprecise, and, at worst, unquantified and vague. This inability to value DERs in a standardized manner has hindered the widespread use of DERs. The DER valuation framework solves this problem and the project team expects that this framework will enable all stakeholders in the renewable energy economy (particularly load serving entities, end-use customers, and developers) to move forward with greater certainty regarding DER costs, value streams, business models, and program structures.

Moreover, the "Green District" program leveraged the public/private partnership framework developed during this project to create value for customers and Lancaster Choice Energy. Using best practices identified, the project partners selected an "enrollment" partnership model that would ensure the private partner and the public entity (in this case, Lancaster Choice Energy) were given incentives throughout program operations. The "enrollment" model was selected over the alternative "incentive" and "shared-value" models because it balanced a simple customer value proposition while ensuring that key actors provided incentives to optimize program outcomes. The project team plans to move forward with Engie Energy Storage as an implementation partner for the Green District program.

While this advanced energy community project was designed to allow the City of Lancaster to accomplish its emissions reduction goals, all of the tools and programs created during this project are designed to be scaled to other communities throughout California. Likewise, the distributed energy resource value optimization tools and the public/private partnership frameworks will be available to support use of similar programs in other communities.

The project team has outlined a comprehensive awareness and engagement plan to ensure the tools and frameworks developed in the Lancaster AEC Project are implemented broadly by other communities.

The team will create a website dedicated to the Lancaster Advanced Energy Community Project and related ZNE tools. This site will include the AEC project background, introductions and explanations of the deliverables developed, and links to the deliverables.

In addition to an accessible on-line database, the project team will continue using conferences and industry events to promote advanced energy community project findings. The team already has discussed advanced energy community project work at several workshops and conferences, including the American Council for an Energy-Efficient Economy and the Community Choice Aggregation summit, and has additional engagements identified. In addition, the ZNE Alliance is a key partner in the California Opportunities for Procurement (Cal-OP) initiative funded by the California Energy Commission, which will align major municipal and other (public and private) institutional purchasers of DERs and energy efficiency with best-in-class technologies and strategies to accelerate DER use and greenhouse gas reduction. The valuation, program, and policy frameworks developed in the Lancaster project will be embedded throughout the Cal-OP program, in collaboration with Lawrence Livermore National Labs, Energy Solutions, Prospect Silicon Valley, California Clean Energy Fund, Ecomedes, and other Cal-OP program leads.

Benefits Created Through the Lancaster Advanced Energy Community Project

Project work resulted in many benefits for different stakeholders. The project team categorized these according to stakeholders:

- **Benefits to Lancaster residents:** The "Green District" program helps Lancaster Choice Energy save on buying electricity during high priced periods. Lancaster residents will ultimately reap these benefits from lower electricity tariffs. Additionally, the emissions reductions achieved through AEC project work will support the city to achieve its energy, environmental, and public health goals.

- **Benefits to the Avenue I development residents:** Living within a zero-net energy microgrid community, residents will benefit from greater energy resiliency, resulting in fewer power outages. Additionally, this will likely occur at a lower long-term cost than comparable conventional developments. Depending on the final design chosen by the Lancaster Housing Authority, the project could save up to $272,000 compared to a conventional deployment.
- **Benefits to Lancaster Choice Energy:** This project will reduce Lancaster Choice Energy's system peak load by up to 1 megawatt and create savings of up to $175,000 annually in energy procurement. Additionally, the energy storage implemented through the "Green District" program will support Lancaster Choice Energy in achieving its energy storage goals.
- **Grid benefits:** The distributed energy resources program and the Avenue I microgrid project will reduce system load spikes, thus alleviating potential stress on the distribution circuits. Secondary effects of this reduction of stress on distribution circuits include fewer electricity outages and the need for fewer repairs. Additionally, value is often created by deferred maintenance resulting from reducing stress on distribution circuits.
- **Benefits to California:** This project reduces GHG emissions within the City of Lancaster, helping the state achieve its climate goals. Beyond this, the project is designed so that impacts achieved within Lancaster can be scaled broadly to other communities in California. Other communities in California can leverage the tools and frameworks developed, creating scalable emissions-reducing and energy-saving projects. Key project developments to reduce costs and increase feasibility of advanced energy communities for other communities include:
    - **Microgrid Technical Framework:** Finding a cost-effective way to create zero-net energy communities capable of operating independently from the main electricity grid (islanding) can provide residents greater energy resiliency, strengthen the grid, and help California achieve its emissions reduction goals. By designing a technical framework that can be scaled to other communities to simplify and streamline the process of microgrid development, this project provides opportunities for other communities to lower the costs and increase the feasibility and success of advanced energy communities.
    - **DER Valuation Framework:** As mentioned, accurately identifying value streams to make direct comparisons between different DER technologies have historically been, at best, complicated and imprecise, and, at worst, unquantified and vague. This has rendered it challenging for communities unexperienced in DER use to adopt and maximize DER opportunities. The project team designed the user-friendly DER community valuation framework to remove this obstacle to widespread DER use by allowing communities to easily understand the value proposition of different DERs, and move forward with greater certainty regarding DER costs, value streams, business models, and program structures.

- **Public/Private Partnership Development Framework:** With robust design strategies, public/private partnerships can leverage the best of what each sector has to offer. Public agencies bring knowledge of community needs and the ability to unite diverse stakeholder groups. Private partners bring efficient value propositions, technical knowledge and expertise, and the ability and resources to scale successful programs. Together, they can unlock value-creating, scalable and smart programs. However, they must be designed and deployed strategically to achieve these results. The program design framework developed through this project enables program designers to do just this - identify which program structure best positions stakeholders to optimize program outcomes.
- **ZNE Residential Community Land-Secured Finance Model:** The ZNE Subdivision Municipal Financial Model serves as a tool for cities, counties, developers, and other stakeholders to explore using land-secured financing to cover energy-related infrastructure costs for a new ZNE community. The model is intended to provide the user information on the general feasibility of financing community ZNE infrastructure with land-secured financing. To achieve this, the model helps answer one or both of these questions:
    1. What are the costs of the community ZNE facilities and what special tax rate would be required to finance these improvements with community facilities district bonds?
    2. At a specific Special Tax rate, what portion of a subdivisions ZNE infrastructure can be financed with community facilities district bonds?

  While additional resources would be required if a community chose to pursue land-secured financing, this tool enables communities to understand the foundational implications of this approach.

While the advanced energy community toolkit developed during this project was designed for application within communities in California, many of these tools can be extended to communities in states beyond California.

CHAPTER 1: Introduction

Purpose

The State of California has set ambitious goals towards zero-net-energy (ZNE) and emissions reduction in the next few decades. In the *2007 California Strategic Plan*, the California Public Utilities Commission (CPUC) set the goal for all new residential construction to be ZNE by 2020, and for all new commercial construction to be ZNE by 2030.[1] Similarly, in the Global Warming Solutions Act (Assembly Bill 32, Nunez, Chapter 488, Statutes of 2006), Governor Brown set the goal that California would reduce greenhouse gas (GHG) emissions to 40 percent below 1990 emissions levels.[2] To achieve these goals, California state agencies, local governments, and technology partners must collaborate on innovative solutions to transition to an efficient, low-carbon economy based on electricity generated from clean, renewable resources.

To support these goals, the Lancaster Advanced Energy Community Project (AEC project), funded by the California Energy Commission, created scalable solutions to support communities to transition to ZNE and reduce emissions. These solutions developed specifically for the city of Lancaster are intended, however, to be widely applicable to other cities and communities. The objectives of the AEC project fall into three categories:

- Develop comprehensive and scalable financial, planning and program frameworks that can be used to accelerate ZNE goals for communities
- Develop innovative business models and policy frameworks that overcome adoption barriers for ZNE residential communities and community distributed energy resources (DERs)[3]
- Provide tools and training for other local governments, project developers, homebuilders, utilities, and other stakeholders on how to use the AEC project's technical and financial models to advance ZNE and DER projects such as solar and energy storage.

By producing and broadly disseminating these tools, and by continuing to support these efforts after Phase I of the AEC project finishes, the AEC project team is committed to accelerating local and regional efforts to achieve California's emissions reduction targets.

Approach

Throughout the AEC project, the ZNE Alliance collaborated with stakeholders from the City of Lancaster and their community choice aggregator, Lancaster Choice Energy (LCE), and the AEC

1 Full document available at: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5305

2 CA SB 32 detail available at: http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf

3 Distributed energy resources (DER) are small scale decentralized, community-generated energy systems such as rooftop solar photovoltaic (PV) panels, natural gas turbines, battery storage fuel cells or wind turbines, and are connect to the grid.

consulting team which included ConSol, Energy Solutions, Olivine, and NHA Advisors. The AEC project team also engaged with other key stakeholders in the community, including the Lancaster City Housing Authority, Southern California Edison's (SCE) interconnection group and the Antelope Valley Transit Authority (which is integrating a fleet of 80 E-buses into their operating fleet). The AEC team also worked with the Lancaster city schools (which is developing aggressive plans for energy storage and microgrid installations, in collaboration with LCE and the ZNE Alliance). The AEC project team shared early work products with stakeholders through the AEC Technical Advisory Committee for quick feedback of diverse perspectives.

AEC project work consisted of two focus areas. In the first, the AEC project team developed financing solutions and technical frameworks for ZNE residential microgrids. The team also analyzed how the value potential of DERs could be optimized, and how to leverage public/private partnerships to best capture this value. These processes and findings are discussed in the following chapters.

CHAPTER 2: Financing and Configuring ZNE Residential Microgrids

During the AEC project, the team investigated the financial and technical pathways to develop ZNE residential microgrids. Finding a cost-effective way to create zero-net-energy (ZNE) communities capable of operating independently from the main electricity grid (islanding) can provide residents greater energy resiliency, strengthen the grid, and help California achieve its emissions reduction goals. Additionally, designing a technical framework that can be scaled to other communities to simplify and streamline the process of microgrid development is critical in lowering the costs and increasing the feasibility and success of advanced energy communities.

Land Secured Finance for ZNE Residential Communities

ConSol examined the legal and policy support for using land-secured finance to help incorporate community solar and energy storage into residential ZNE communities. Key findings are summarized.

Land-Secured Finance

Historically, land-secured financing has been used to fund the basic infrastructure required for new developments, such as roads and sewage treatment facilities. The funding is raised by issuing bonds by a special tax district known as a community facilities district (CFD). Owners of the properties that benefit from the infrastructure agree to a lien on the property that is repaid through a special tax. The taxes raised are used to pay the debt service (interest and loan principal) and retire the bonds, which are secured using the property as collateral.

Establishing Community Facilities Districts

Land-secured financing can be used to finance infrastructure or improvements to existing communities, or to fund the infrastructure necessary to allow the building of new communities. In the former case, the CFD and imposing the associated tax must be approved by two-thirds of the voters in the district. In the latter case, the CFD can be formed at an early stage of development, where the only effective "voter" would be the developer (or a limited number of developers) of the planned community. This model removes the risk of the proposed tax being voted down. The developer is initially responsible for the full tax payment, with the burden shifting to the owners of the properties as the community is developed.

Legal Basis for Community Facilities Districts

Mello-Roos Act (1982)

The Mello-Roos Community Facilities Act of 1982 describes a mechanism for financing facilities and services by using special assessments within CFDs. It has been used to finance a wide variety of infrastructure projects in new residential development and within existing communities. Through this process, municipal bonds are issued to generate funding that can be invested into various forms of infrastructure. Mello-Roos districts are most often formed before the division and sale of lots, so existing residents do not shoulder the burden; only benefiting property owners repay the debt through special assessments guaranteed by property liens. Typical infrastructure improvements used for CFDs include sewers, landscaping, roads, and other amenities required to meet increased demands placed on local agencies as the result of new development.[4]

Use for Energy Efficiency Improvements and DERs

Several legislative changes have been made to expand the scope of facilities eligible for Mello-Roos financing to include energy efficiency and renewable energy generation. San Francisco and Berkeley were the first cities to fund clean energy using Mello-Roos under their city charter authorities.[5] State legislation as Senate Bill 555 (Hancock, Chapter 493, Statutes of 2011) provided statutory authority for this approach in 2011. SB 555 allows CFDs to finance renewable energy, energy efficiency, and water efficiency improvements on private property[6] by adding and amending language in sections of existing state codes pertaining to local government and CFDs.[7] SB 555 states:

"A district may also finance and refinance the acquisition, installation, and improvement of energy efficiency… and renewable energy improvements that are affixed, as specified in Section 660 of the Civil Code, to or on real property and in buildings, whether the real property or buildings are privately or publicly owned."[8]

Use for Distribution Infrastructure

State regulations also indicate that, in limited cases, CFDs may finance distribution infrastructure pertaining to renewable energy resources, such as the construction or undergrounding of electrical transmission lines. This may be initiated by the city to "provide access to those services to customers who do not have access to those services."[9] Use and conveyance of these facilities can be transferred to a public utility if the CFD is reimbursed in whole or in part. Work with utilities on the long-term operation of the infrastructure is necessary as the districts are prohibited from operating, maintaining, or having ownership interest in any facilities for the transmitting electrical energy.[10]

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4 Bort, D.; 2006, *An Introduction to California Mello-Roos Community Facilities Districts*, p.7 Orrick, Harrington & Sutcliffe LLC.

5 Kaatz, J. and S. Anders. 2014, *Residential and Commercial Property Assessed Clean Energy (PACE) Financing in the California Rooftop Solar Challenge Areas*, Center for Sustainable Energy.

6 California Stats 2011 Ch. 493

7 California SB 555 Bill Detail https://www.billtrack50.com/BillDetail/7979

8 California Gov't Code §53313.5(l)

9 California Gov't Code §53313.5(e)

10 California Gov't Code §53313.5(h)

Upfront payment for distribution line extensions, followed by long-term ownership and operation by the utility, is the typical process used for interconnecting new residential subdivisions in California. In this process, a homebuilder files an interconnection request with the utility or distribution service operation and provides an upfront cost-recovery payment to the utility for line planning and construction. After completing the homes, an allocation credit is then issued back to the builder on a per meter basis, under CPUC-approved rules.[11] Builders remain liable for distribution costs in excess of the allocation credit, potentially resulting in additional costs for the residential unit.

Limitations for New Home Construction

Language included in SB 555 indicates the authority is geared toward residential retrofitting rather than new building, with apparent limits to its application in new home construction (emphasis added):

*"This chapter **shall not be used** to finance installation of energy efficiency, water conservation, and renewable energy improvements on a privately-owned building or on privately-owned real property in connection with the **initial construction of a residential building** unless the initial construction is undertaken by the intended owner or occupant."*[12]

Financing Energy Efficiency Improvements Under Mello-Roos

Notwithstanding this restriction, Section 53313.5 of the California Government Code states that:

"A community facilities district may also finance the purchase, construction, expansion, improvement, or rehabilitation of any real or other tangible property with an estimated useful life of five years or longer or may finance planning and design work that is directly related to the purchase, construction, expansion, or rehabilitation of any real or tangible property. (…) A district may only finance the purchase of facilities whose construction has been completed, as determined by the legislative body, before the resolution of formation to establish the district is adopted pursuant to Section 53325.1, except that a district may finance the purchase of facilities completed after the adoption of the resolution of formation if the facility was constructed as if it had been constructed under the direction and supervision, or under the authority of, the local agency that will own or operate the facility."[13]

The SB 555 legislation restricts the use of CFDs to fund energy efficiency and renewable energy improvements for residential properties constructed by a merchant builder (California Gov't. Code §53313.5[l]). However, a careful read of the text indicates that this restriction may not apply if the renewable energy improvements are constructed on publicly owned land, creating opportunities for financing offsite solar. Furthermore, if a private party constructs the

11 Southern California Edison – Rule 15, Line Extension https://www.sce.com/NR/sc3/tm2/pdf/Rule15.pdf

12 California Gov't Code 53313.5(l)

13 California Gov't Code 53313.5

buildings, and that party retains the building and leases the units as opposed to selling them, they remain the "intended owner" and the restriction may not apply.

Application of Mello-Roos to Community Solar Facilities

A possible reading of the law would be that the construction of a community solar facility would not be an "energy efficiency improvement," but an infrastructure facility, more akin to a sewage treatment plant. Section 53313.5 would also allow a third party to build a solar facility and sell it to the CFD, as long as the facility is built "as if it had been constructed under the direction and supervision … of the local agency."[14] This transferred ownership model would allow using the tax equity investment to finance part of the construction costs, which would effectively reduce the cost to the CFD.

Avenue I Project

Land-secured financing was one of the options considered to fund the renewable energy infrastructure for the Avenue I project. The City of Lancaster owns Avenue I and is looking into the possibility of a larger citywide CFD for energy related improvements in new and existing communities. CFDs are not proposed for use at the Avenue I site since the local government has access to adequate funding sources to obtain renewable resources supporting its community choice aggregator (CCA) program. The microgrid configuration of the Avenue I project relies on numerous small rooftop solar and on-site storage systems located behind a master meter for the energy needs. Although the municipal bonds issued through CFDs could be used, in theory, to finance numerous smaller scale DERs owned by a single entity, it is more attractive to use in community-scale applications that consist of larger DER systems that require access to larger sums of capital for planning, permitting, and construction.

Next Steps for Exploring Land-Secured Finance

Transition to Zero-Net Energy

The *2016 Building Energy Efficiency Standards*, effective January 1, 2017, for the first time provided builders with the option to include on-site renewable energy generation to offset a portion of annual building energy consumption. To meet current 2016 Title 24 Building Energy Efficiency codes, homebuilders often choose this option for compliance, and use rooftop photovoltaic (PV) solar panels as a performance (rather than a prescriptive)[15] compliance measure. For future code cycles, solar will become a requirement in addition to building envelope improvements as state policymakers seek to achieve ZNE for all residential new construction—an objective stated in the California Public Utility Commission's (CPUC) *ZNE Residential Action Plan*.[16]

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14 California Gov't Code 53313.5

15 *Prescriptive code compliance* means that every component of the building meets a defined standard. Performance compliance does not require components to meet standards provided that the building as a whole uses no more energy than the same building built to prescriptive code.

16 *New Residential Action Plan 2015-2020 Executive Summary*. www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5307

Expanding the ZNE Definition

As written, the building code does not allow using offsite solar storage to meet energy efficiency compliance standards. The California Energy Commission, however, has drafted language for the 2019 code cycle that specifically addresses the possibility of using community solar and storage facilities to meet Title 24 requirements.

This draft language states:

"A community shared solar system, other community shared renewable system, community shared battery storage system, or combination of the aforementioned systems (hereinafter referred to as a community shared solar or battery storage system) may be approved by the Commission as a partial or total offset of an onsite solar electric generation system and/or battery storage system that is otherwise required by Section 150.1(b)2 of Title 24, California Code of Regulations, Part 6. To be approved the community shared solar electric generation or community shared battery storage system shall meet the following requirements…"[17]

The requirements are essentially:

- The solar facility is planned and permitted with the homes it is serving.
- The power provided is at least equal to the power that would be required for the dwelling units to meet code.
- The power is dedicated to the specific residences and may not be transferred to other buildings, and shall have a useful life of not less than 20 years.

The Energy Commission considered four possible models for offsite solar to explore if they meet the criteria established in the draft language. Table 1 shows the options considered (compared to onsite PV), with the dots representing matching attributes with onsite PV (green) and potential feasibility though not necessarily equivalence to on-site PV (yellow). The assignment of green or yellow values would depend on the ability of the model to be additional, dedicated, durable, temporal, quantifiable, verifiable, beneficial to home, enforceable and administratively feasible.

17 http://docketpublic.energy.ca.gov/PublicDocuments/17-BSTD-01/TN221247_20170920T143237_Draft_2019_Standards_Part_1_Chapter_10.pdf, Section 10-115a

Table 1: Models for Community Solar Facilities

	Additional	Dedicated	Durable	Temporal	Quantifiable	Verifiable	Benefit to homes	Enforceable	Administratively Feasible
Onsite PV	Green	Green	Green	Green	Green	Green	Green	Green	Green
PVs dc connected to home from other subdivision location	Green	Green	Green	Green	Green	Green	Green	Green	Yellow, Red
Green Tariff Shared Renewables Program (GTSR)	Green	Red	Red	Yellow	Yellow	Yellow	Yellow, Red	Red	Red
Builder PVs at other location sharing bill savings with homes	Green, Yellow	Green, Yellow	Green, Yellow	Green	Green, Yellow	Green, Yellow	Green, Yellow	Green, Yellow	Green, Yellow
Local Government Community Facilities District (CFD)	Green, Yellow	Green, Yellow	Green, Yellow	Green, Yellow	Green, Yellow	Green, Yellow	Green, Yellow	Green, Yellow	Green, Yellow

Source: California Energy Commission Community Solar Presentation, Page 7[18]

This policy change will open up using community solar facilities when developing new planned communities. For land-secured financing of community-scale renewables to work, there must be a way to ensure that the residents who have been assessed a property tax receive an equal or greater financial benefit from the shared generation or energy storage asset. In other words, the residents must receive a bill-credit from the electric utility that reduces their annual energy costs by an amount greater than the annual debt-service (tax assessment) for the renewable energy system. Otherwise, it is unlikely that this tool will have broad appeal.

In most of California, the CPUC sets rules (net-metering tariffs) for measuring “behind-the-meter” energy generation. These various net-metering tariffs apply to rooftop PV systems on single-family homes, as well as larger PV and storage systems that may be shared between groups of commercial buildings. There is no utility tariff (metering arrangement and rate schedule) that allows single-family homes to share off-site renewable generation. To apply the land-secured financing tool as envisioned in this report, new tariffs must be developed.

The next steps in developing the policy model for land-secured financing of community solar are to integrate:

- *Mechanisms for funding* the construction of the facility under existing laws.
- *Ownership models* ensuring that power generated is tied to the new construction to ensure compliance with building codes.
- *Tariff structures* to ensure that final property owners receive energy savings which at least match the tax burden they have assumed.

18 http://docketpublic.energy.ca.gov/PublicDocuments/17-BSTD-01/TN220861_20170823T094322_82217_Community_Solar_Presentation.pdf accessed 1/18/2018

Suitability of Land-Secured Finance for Renewable Generation and Storage

Using land-secured finance for CFDs to fund renewable generation and storage associated with a new development should be considered on a case-by-case basis, since there are advantages and potential disadvantages to this method of financing.

Advantages

Beginning January 1, 2020, proposed updates to the *Title 24 Building Energy Efficiency Standards* will require greater energy efficiency in new home construction. Solar generation and battery storage are anticipated to play a critical role in achieving code compliance. Outfitting homes with rooftop solar and battery storage technologies can add to the per-unit cost of residential construction by thousands of dollars. Homebuilders incur these costs, which are then rolled into the purchase price of a new home, resulting in a higher initial purchase price for homebuyers. Moving to off-site solar and storage provides the energy necessary for compliance to be purchased at a lower cost per kilowatt hour (kWh). Using a CFD to fund offsite solar rather than using conventional financing can lower the cost of borrowing because CFDs offer municipal bonds that are tax exempt and have attractive terms based on a high likelihood of repayment, because of the lien attached to the properties.

When the 2019 building code takes effect, offsite solar will become increasingly attractive as a compliance method for new developments. To be credited towards compliance, the solar generation must be dedicated, quantifiable, and verifiable. Using a CFD provides an administratively straightforward path to establishing these attributes because of the effective ownership of the generating facility by the houses in the CFD. This ownership is established by the CFD and maintained by the payment of the special tax.

Disadvantages

There are, however, potential disadvantages of using land secured financing.

- **Compliance**. Under current code, offsite renewables are not indicated as a Title 24 compliance option. Using a CFD to fund individual rooftop system introduces administrative and legal complexities, such as insurance or access for maintenance.
- **Default.** Using special taxes and a lien on the property to guarantee payment of the bonds creates a long-term obligation on the developer (initially) and the homeowner (after purchase). If the development is not completed, or sales of houses are below expectations, the obligation to pay the special tax remains attached to the lots. This adds barriers to resale of the lots.
- **Bond Market**. Issuing bonds is a market dependent event. If financial markets change between the initial planning of the development and forming the CFD, and issuing the bond, changes in interest rates may make the bond repayments prohibitively expensive. Given the time that is required between initial planning for a new development and the beginning of construction, this is a risk for the developer. Using conventional methods, the solar financing would most likely be established in parallel with financing of the development as a whole.

- **Tax Burden**. A special tax will appear on owners' property tax bills, which may deter buyers. CFDs that provide direct benefits to the assessed property are also not eligible for state and local income tax deductions for individuals or households.[19,20] The additional tax can lower the amount of the mortgage for which buyers can qualify, thereby limiting the pool of buyers. This applies not just to the initial sale, but also to subsequent resale (during the repayment period of the bonds), which can further deter buyers.

For more details on the path towards land-secured financing for community solar PV and efficiency upgrades, please see the **Legal and Policy Framework for Using Land-Secured Finance to Achieve ZNE** in Appendix A.

ZNE Residential Community Land-Secured Finance Model

The ZNE Subdivision Municipal Financial Model (model) serves as a tool for cities, counties, developers, and other stakeholders to explore using land-secured financing to cover energy-related infrastructure costs for a new ZNE community. The model is focused on two related analyses. It estimates the capacity of ZNE infrastructure necessary to support the community and estimates the tax rate required to fund this infrastructure with a CFD bond issue. Additionally, it estimates the maximum amount of bond proceeds that would be available to fund ZNE infrastructure for a given tax rate. Although the two analyses represent different approaches, combined they can be informative in exploring the feasibility of using CFD bonds for ZNE infrastructure.

Inputs and Assumptions

The model requires a minimum number of inputs to perform the two analyses and relies on documented assumptions for many of its calculations and output. In many cases, the user can override these assumptions if better project-specific information is available.

The model estimates energy consumption for the residential community based on characteristics of the proposed units. The estimated energy consumption is then used to estimate the capacity and cost of the community ZNE project. This can include community solar, storage, and distribution systems.

Model Intended for Planning Purposes

The model is intended to provide the user information on the general feasibility of financing community ZNE infrastructure with land-secured financing. To achieve this, the model helps answer one or both of the following questions:

1. What are the costs of the community ZNE facilities (community facility input page shown in Figure 1) and what Special Tax rate would be required to finance these improvements with CFD bonds?
2. At a specific Special Tax rate, what portion of a subdivisions ZNE infrastructure can be financed with CFD bonds?

19 Winston & Strawn, Briefing: Deductibility of Mello-Roos and Other Tax-related Assessments in California

20 https://www.ftb.ca.gov/law/meetings/attachments/090705/5.pdf

This model is for high level planning purposes. If an actual CFD financing is deemed feasible and pursued, the stakeholders would need to assemble a financing team to structure and issue CFD bonds. The stakeholders would also need to refine infrastructure and financing assumptions to a level of detail that is beyond the scope of this model.

Figure 1: ZNE Financial Model Screenshot – Inputs Page

District information

Parcel characteristics

Energy consumption and other calculations are based on the characteristics of the parcel types described below. Enter information on the floor area of each unit, the number of parcels, and the unit type. The model has two built-in residential unit types and allows for a custom unit type. The built-in unit types are based on the California Energy Commission Alternative Calculation Method Approval Manual

	Floor area (sq ft)	# of parcels	Unit type	Total sq ft
Parcel type #1	2,100	100	SF_2100	210,000
Parcel type #2	2,100	100	SF_2100	210,000
Parcel type #3	2,100	100	SF_2100	210,000
Parcel type #4	2,100	100	SF_2100	210,000
Parcel type #5	2,100	100	SF_2100	210,000
Total		**500**		**1,050,000**

Source: Munitrend analysis, 2017

This model is for high level planning purposes. If an actual CFD financing is deemed feasible and pursued, the stakeholders must assemble a financing team to structure and issue CFD bonds. The stakeholders must also refine infrastructure and financing assumptions to a level of detail that is beyond the scope of this model.

Analysis Not Covered by the Model

The model does not analyze the overall economic viability of developing a ZNE community. Many factors go into the decision to develop a ZNE subdivision, including political, regulatory, and economic factors. Homes in a ZNE community may or may not have higher construction costs and may have higher market values. The model assumes the decision to create a ZNE subdivision has been made and estimates the viability of financing certain community infrastructure through CFD bonds.

Next Steps

The model is intended to provide a planning-level analysis of the feasibility of using CFD bonds to finance ZNE community infrastructure projects. Figure 2 explains the fundamental calculations undertaken by the model. Should a municipality choose to move forward with CFD financing, a more refined analysis would be necessary. Consultants and legal counsel would be required to draft the legal documents, establish the final taxing methodology, and structure the bond issue for the municipality.

Figure 2: ZNE Financial Model Screenshot – Tax Rate Calculation

Tax rate given project cost		
Bond proceeds required		
Total project cost	A	8,392,742
Costs of issuance	B	419,637
Total par amount of bonds required	**C = A + B**	**8,812,379**
Bond issue assumptions		
Interest rate		5.00%
Term of bonds		20
Estimated annual debt service		707,128
Tax rate		
Annual debt service	A	707,128
Target debt service coverage	B	110%
Annual tax revenue required	**C = A x B**	**777,841**
Total square feet	D	1,050,000
Tax per square foot	**E = C / D**	**$0.74**

Source: Munitrend analysis, 2017

Technical Approach to Residential Microgrids

The AEC project team has developed a technical design toolkit for creating a ZNE residential master-metered community. In that process, the team collaborated with LCE and the Lancaster Housing Authority to work through technical challenges in the context of a real-world site, the planned "Avenue I" ZNE community microgrid.

Goals and Background

The goals of this project component were to create a comprehensive toolkit to guide local governments, project developers, and CCAs in developing master-metered ZNE communities and support LCE in developing the Avenue I community.

Avenue I is a 5.84-acre lot located in Lancaster between Avenue I and West Avenue H, and between Elm Avenue and Sierra Highway. The project is owned by the City of Lancaster and is planned for a single-family attached development of 75 units. There will be three floor plan options ranging from three to four bedrooms, and from 1,400 to 1,900 square feet. The entire development will include solar and energy storage to meet the electrical power demand of the community. LCE will own the community's DER assets and infrastructure, and operate control systems guiding energy generation and storage. The residential units will be operated by the Lancaster Housing Authority and rented as low-income units.

The project architect designed three conceptual plans for the development and is obtaining tentative tract map approval. Once the Lancaster Planning Commission and City Council approve the tentative tract map, the architect will develop the project's architectural and construction documents and prepare to break ground on the project. The AEC project team's work will provide a reference to understand the trade-offs and benefits of different aspects of a residential microgrid. Based on research, analysis, and modeling, the AEC project team will recommend a technical design of the community microgrid to the city of Lancaster. The recommendation will include component sizing, technical schematics, and controls that can be incorporated into the architectural and construction documents. Additionally, the technical design outlines the project's interconnection requirements and process needed to integrate the community microgrid into the larger grid.

Stakeholder Perspectives

The AEC project team identified market actors who may be involved in the design, development, operation, and maintenance of a residential microgrid. Each market actor has a unique role to play and a different definition of successful implementation. Table 2 presents the market actors, their roles, what defines success from their perspective, and barriers to achieving success.

Table 2: Market Actors Involved in the Design and Implementation of Residential Microgrids

Market Actor	Roles	Definition of Success	Primary Barriers
Developer	• Oversee design, development, financing, and deploying residential microgrid • Hire design/build contractors • Secure project financing	• Profit on design and sale of developed resources • Establish market differentiation by showcasing innovative design and financial models • Reduce time and cost of distribution and interconnection	• Limited use of residential microgrids on which to base design, financing, implementation • Technology risk relative to operational, performance, and maintenance challenges
Builder	• Design and build high-efficiency homes • Sell homes	• Profit on building sale • Adhere to building code requirements	• Incremental cost to build high-efficiency homes • Ability to sell homes in microgrid:

		• Establish market differentiation by showcasing innovative design • "Easy" design process • Streamlined permitting process	○ Lack of consumer demand for ZNE buildings ○ Concern that microgrid could limit homeowners' ability to control their own loads • Increased burden on builder to meet more restrictive design requirements • Increased burden of collaborating with more entities during the design phase
Consultant for Grid Infrastructure	• Design distribution system for microgrid development • Build distribution system for microgrid development	• Profit on design (or design/build) • Adhere to all code requirements • Establish market differentiation by showcasing innovative design	• Limited existing residential microgrid designs upon which to base designs • Increased design burden relative to typical distribution system design • Increased burden of collaborating with more entities during the design phase
Financer	• Provide financing for microgrid design and development	• Profit on financing • Minimize risk of default • Establish market differentiation by showcasing innovative design	• Residential microgrids are new to the industry and therefore pose risk. • Uncertainty about financial model of microgrid operation • Uncertainty about technical feasibility of microgrid

Building Officials	• Confirm buildings are compliant with all relevant building code requirements	• Compliance and enforcement that protects public safety • Some AHJs may define success by fast and easy application processes	• High-efficiency designs may use technologies that are new to building officials, which could slow down approval process
Homeowner	• Purchase or rent home • Live in home within the microgrid • Participate in load management strategies • Pay for energy and energy services	• Home has high potential to appreciate over time • Reliable access to the comforts and amenities provided by energy (like heating, cooling) • Energy cost savings • Seamless interaction with energy provider • Seamless load management	• Uncertainty about long-term financial implications of home within microgrid • Need to feel comfortable with more active management of energy loads • Misperceptions that "ZNE" means no energy cost • Energy costing for microgrid needs to be intuitive
Load Serving Entity (LSE)	• Build and maintain distribution system within microgrid • Manage electricity reliability within the microgrid • Manage how microgrid interacts with larger grid • Offer incentive programs for load management	• Streamlined billing for energy users within microgrid • "Easy" operation of microgrid • Availability of grid resources	• Cost to complete design review and approval for a microgrid resource are higher than costs to approve traditional resources • Billing individual energy users within the microgrid could be complicated and/or time consuming

Utility	• Approve microgrid connection to larger grid • Provide electricity to the microgrid when necessary	• Microgrid provides resource to help manage reliability of larger grid • Microgrid helps defer distribution system upgrades	• Operating the microgrid (or working with the microgrid operator) could require more resources than maintaining relationships with typical customers
Microgrid Manager	• Manage microgrid to achieve desired use case • Establish desired control strategies for resources within the microgrid	• Profit from management services • Achieve the success metrics defined by the use case(s) • Establish market differentiation by demonstrating successful management of residential microgrid	• Uncertainty about financial model of microgrid operation • Uncertainty about technical feasibility of microgrid • Limited existing residential microgrids in operation upon which to base control strategy
Control Service Provider(s)	• Manufacture and sell controls for resources within the microgrid • Provide control services • Implement control strategies to achieve goals for desired use case	• Profit from sale of controls and/or control services • Cost effective to manage the aggregated load of all the houses within a community • Integrate a fleet of endpoints for participation in demand response and wholesale markets	• Limited existing residential microgrids in operation upon which to base control strategy • Residential microgrids are not a typical business model, so may not fit within control service providers' standard offerings

Demand Response Provider / Aggregator	• Aggregate demand response resources from microgrid with other resources • Manage bids into wholesale markets (if applicable)	• Profit from role aggregating demand response resources • Offer seamless experience for microgrid operator and/or homeowners	• Uncertainty about the reliability of demand response resources from microgrid • Potential metering, telemetry, and the like, if managing multiple loads or load centers
Solar Photovoltaic Service Provider	• Own, operate, and maintain solar photovoltaic resources	• Profit from role owning and operating battery resources • Offer seamless experience for microgrid operator and/or homeowners	• Uncertainty of the role of batteries in the system for energy storage, reliability, and the like
Battery Service Provider	• Own, operate and maintain storage resources, potentially in conjunction with solar PV governance	• Profit from role owning and operating battery resources • Offer seamless experience for microgrid operator and/or homeowners	• Uncertainty of the role of batteries in the system for energy storage, reliability, and the like
Municipal Government	• Establish local ordinances and zoning rules that could support microgrids • Collect property taxes • Potential to provide financial incentives for microgrid projects	• Leadership in energy and climate action on a local level • Reliable revenue from property taxes	• Uncertainty about microgrid technical and economic feasibility

Homeowners Association (HOA)	• Maintain community resources, including community solar or battery storage resources • Market, manage, and sell homes • Collect HOA dues • Potential to provide incentives for microgrid projects	• Maintain or increase home values • Maintain community resources	• Uncertainty about requirements for managing microgrid resources • Uncertain financial model associated with managing all or part of the microgrid • Uncertainty about how microgrid could impact home sales and property value

Source: Energy Solutions analysis, 2017

Microgrid Use Cases

After considering input from stakeholders including LCE and the Lancaster Housing Authority, the AEC project team identified three potential use cases for the Avenue I microgrid: resiliency and excess generation (R&EG), energy bill savings (EBS), and emissions reductions (ER). These use cases are the foundation of the technical design analysis as they affect the load estimate, DER components, sizing configurations, and control strategy required for the microgrid. For example, the resiliency use case would be designed to maximize the microgrid's islanding capability, which requires larger generation and storage components. The project team analyzed the cost, energy performance, and emissions results of each use case to optimize the microgrid design for the final recommendation. Table 3 summarizes the use cases analyzed.

Table 3: Summary of Microgrid Use Cases Considered

Use Case	Objectives	Design Consideration	Value Streams
Resiliency & Excess Generation (R&EG)	• Highly reliable • Maximize islanding capability • Support loads with DERs • Support future electric vehicle (EV) penetration	• Initially oversized PV/storage capacity to support future EV loads • Battery sized to meet 2030 EV penetration, PV sized to meet 2045 EV penetration.	• Participate in demand response or wholesale programs using excess generation • Near complete functionality in the event of grid outages or natural disasters

Energy Bill Savings (EBS)	• Minimize the cost of energy • Maintain some islanding capability	• Reduced islanding capability allows for smaller PV/storage	• TOU price arbitrage • Some functionality in a grid outage or natural disaster •
Emissions Reductions (ER)	• Minimize energy related emissions	• All-electric homes • Consider life-cycle emissions	• Climate action plan goals

Source: ZNE Alliance

Technical Design Process

To properly size and model the microgrid, the AEC project team estimated the electrical load generated by the Avenue I community. The largest contributors to the load are the homes and the anticipated number of electric vehicles into the community by 2045.

Next, generation and storage components were sized to achieve the targeted islanding capability in the EBS and R&EG use cases, and to minimize life-cycle emissions in the ER use case. The design and operation of each use case was then optimized to achieve the lowest net present cost as constrained by the sizing requirements. The AEC project team also considered each use case's ability to participate in demand response and wholesale electricity market programs, and accounted for these value streams in the net present cost optimization.

To assess the various combinations of microgrid infrastructure and operational strategies, the AEC project team developed models of the project using the HomerPro microgrid simulation software.[21] A visual representation of the key inputs and outputs of the modeling process is shown in Figure 3.

Assumptions

The AEC project team made the following high-level assumptions when developing the project's technical design:

- **Grid Embedded Microgrid**. The AEC project team did not consider scenarios in which Avenue I is an independent, off-grid community.
- **100 Percent Renewables Design**. Given the city of Lancaster's commitment to climate change mitigation and renewable energy laid out in its draft Climate Action Plan, only designs with renewable energy generation[22] were considered. No on-site diesel or gas electricity generation was considered.
- **Islanding Capability**. While various definitions of "microgrid" exist, the AEC project team assumed the defining characteristic of a microgrid is its ability to disconnect and "island" from the larger macro-grid. Thus, cases in which the project operates strictly as a net-

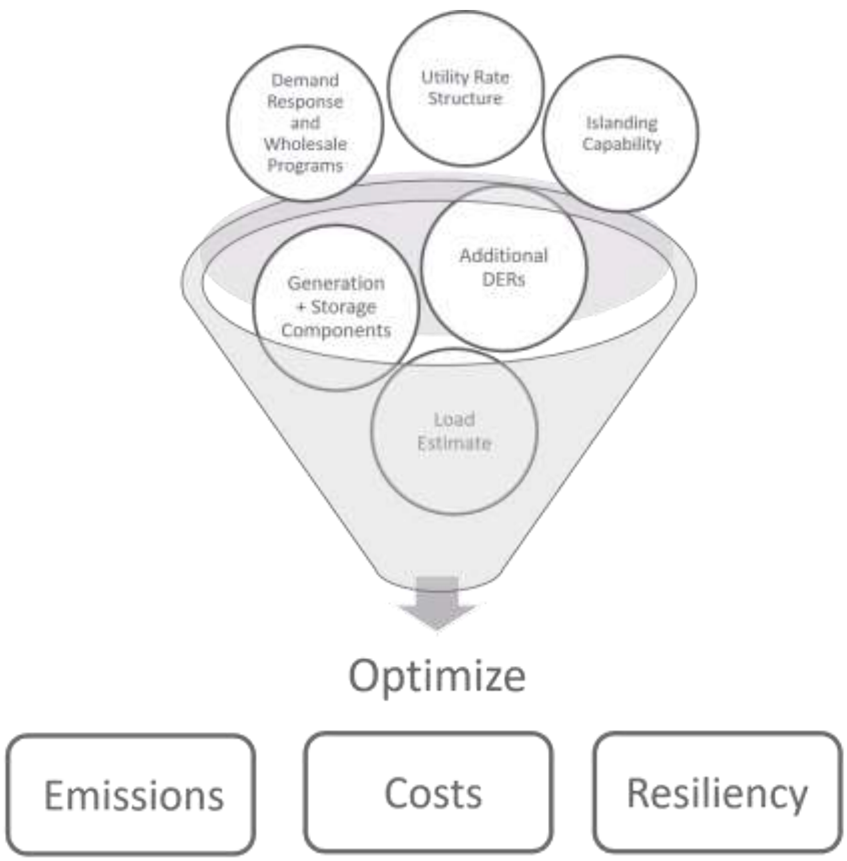
21 Homer Pro Software, https://www.homerenergy.com/homer-pro.html.

22 Lancaster's ZNE Ordinance requires that each home has at least 2 watts/ft^2 of installed solar. Therefore, only solar generation was considered as a renewable energy source for the Avenue I microgrid.

metered, community solar development without energy storage infrastructure were not considered. While the targeted islanding capability varies by use case, only designs with some combination of generation and energy storage were considered. Also, implicit in this assumption is that the microgrid must capable of re-synchronizing with the macro-grid after any islanding event (planned or unplanned).

- **25-year Period of Analysis.** The AEC project team chose 25 years (2020-2045) as the period to analyze various design configurations and performance. Due to the stage of project development, the AEC project team assumed that Avenue I would not likely be operational until approximately 2020. Projecting out 25 years from that point allows for considering storage replacement costs, changes in utility rates, and EVs without introducing amplified levels of uncertainty into the analysis.
- **Lancaster ZNE Ordinance**. The AEC project team assumed Avenue I's compliance with the 2017 Lancaster ZNE Ordinance. Since behind-the-master-meter generation is essential to the microgrid operation, the AEC project team constrained the design options to ensure each home in Avenue I has at least 2 watts/ft^2 of installed solar.

Figure 3: Modeling Approach for the Avenue I Microgrid



Source: Energy Solutions analysis, 2017

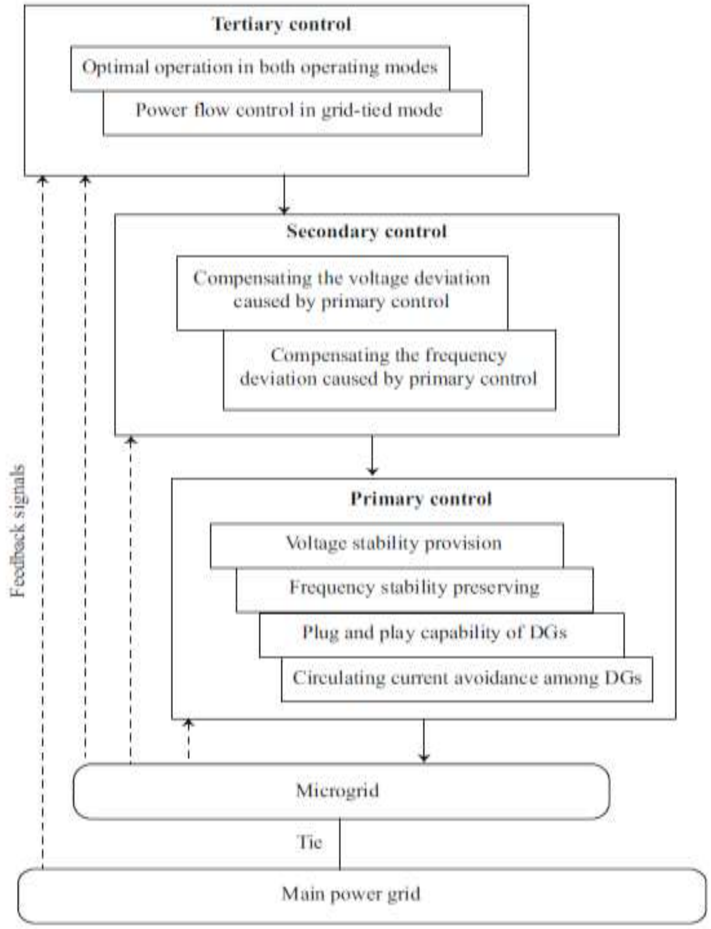
Control Systems

A microgrid's controls are responsible for managing power balance, demand side management, and economic dispatch. Efficient controls and control schemes make the microgrid resilient in its operation in both grid connected and islanded modes. To achieve resiliency, the controller must coordinate generation and load components stably and reliably. Control of a microgrid relies on numerous devices and strategies:

1. Smart meters provide real-time power information such as voltage and frequency while tracking grid and microgrid conditions for precise load distribution as well as power purchases and sales.
2. Supervisory Control and Data Acquisition software using an interconnected network (Wi-Fi) must be implemented for control of all resources within the microgrid.
3. Protective relays, inverters, and reactive equipment balance the energy present in the grid.
4. Control strategies must be implemented for each microgrid based on the available resources, load types, and other factors. Control strategies can be broken down into two types:
    a. Centralized: A control scheme using a single central controller that requires extensive communication between the central controller and controlled units. The central controller makes all decisions.
    b. Decentralized: A control scheme accomplished with local controllers at each available unit. These controllers only receive data from locally measured data and use self-regulation techniques to maintain tolerance within the larger grid.

Often a combination of centralized and decentralized strategies can be hybridized into a hierarchal control structure as shown in Figure 4. In this hierarchal control, primary control is decentralized to local units, which in this project are represented by controllable inverters at the PV and battery energy storage system installations. Secondary control is typically centralized via a central controller at the point of common connection (PCC) with the incumbent utility. The central controller aggregates the individual data from the decentralized controllers to correct deviations and coordinate connection with the incumbent grid. Tertiary control defines "smart grid" or "next-level" microgrid controls, which includes participation with utility demand response (DR) programs or wholesale market events.

Figure 4: Hierarchal Control Structure for Microgrids



Source: Bidram, A. and Davoudi. A. Hierarchical Structure of Microgrids Control System. IEE Trans. Smart Grid, vol. 3, no. 4, pp. 1963-1976, Dec 2012.

For the Avenue I microgrid, primary and secondary control will be necessary for smooth operation of the microgrid. Tertiary control will be optional, but will optimize the performance of the microgrid. DER level inverters will constitute the primary control (locally managing energy from the distributed solar and storage) and a microgrid central controller (MGCC) will constitute the secondary and tertiary control (balancing energy within the system and coordinating participation in wholesale and DR events). A final design and control structure will be included in the final technical design report.

Design Results

Implementation Assumptions

The final microgrid design will use a MGCC for coordination with the main grid at the PCC. DC-to-AC inverters will be used in tandem with solar installations on the rooftops of the Avenue I homes, a conversion rate of 96 percent is assumed based on average inverter efficiencies from California Solar Initiative's online database. Bi-directional capabilities for the battery storage systems (DC-coupled) and controlled EV charging capability are assumed.

Sizing Considerations by Use Case

The AEC project team explored the three use cases for the Lancaster Avenue I microgrid. Each of the three use cases requires a different sizing of components, but all use cases are some combination of solar PV generation and battery storage.

Energy-Bill Savings (EBS)

In the energy-bill savings (EBS) use case, the overall goal of the microgrid is to reduce the individual customer's energy bill. Given the associated capital costs of energy storage, the highest bill savings would be achieved with a typical PV solar installation. To maintain microgrid capabilities, the use case was modeled to constrain islanding capabilities to a minimum of 30 percent, and a maximum of 90 percent.

To maximize the net benefits delivered by the microgrid in this use case, the sizing of the PV generation should be sufficient to take advantage of programs such as net energy metering (NEM). Participating in these programs will allow the Avenue I community to have lower monthly energy bills and recuperate costs by selling excess energy back to the grid via direct solar generation or dispatched battery storage. However, given the proposed ownership structure (LCE owns the energy assets in Avenue I) whether or not Avenue I participates in LCE's NEM program is a topic for future consideration. In the model, Avenue I is allowed to export energy to the grid, but is not compensated via a NEM sell back rate. Avenue I is assumed to be enrolled in SCE demand response (DR) programs, and the model accounts for these value streams.

Maximizing the energy bill savings for the customer also benefits LCE by minimizing the costs incurred by the CCA. As the CCA is responsible for the cost of the batteries, LCE will have a lower upfront cost as it will purchase less generation and storage equipment. Furthermore, LCE can recover upfront costs quicker by potentially increasing its profit margins in the customer rate payments for the EBS use case (which still could be lower than the rates for the resilience & excess generation use case).

Emissions Reduction (ER)

In the emissions reductions use case, PV and storage components are sized to minimize life-cycle emissions from the project's energy use (electric and natural gas in the mixed-fuel case) and microgrid infrastructure during the 25-year analysis period. Given the significant impact of primary natural gas consumption in Avenue I homes (for space and water heating, cooking, clothes drying), the emissions reduction case is likely to favor an all-electric house design. The avoided cost of natural gas infrastructure (including meters and pipelines) is accounted for in the model. Additionally, grid interactive heat pumps are assumed for water heating because the microgrid will have a sophisticated central controller. Design configurations for the emissions reduction use case are constrained by a minimum 40 percent islanding capability and a maximum 90 percent from the cost implications described.

Lifecycle emissions are accounted for by the following methods:

- **Grid emissions.** The 2016 hourly California grid mix is used to generate hourly lifecycle emissions factors. These emissions factors account for the full life cycle of electricity production, including embodied emissions in power plant construction. Using hourly emissions factors helps to account for the time-varying nature of emissions associated with grid electricity. To account for a progressively cleaner grid mix in the future, the emissions from grid electricity in each year are adjusted according to the Energy Information Agency (EIA) *Annual Energy Outlook*.[23]
- **Microgrid Infrastructure.** Emissions from microgrid PV, converter, and battery components are analyzed using emissions factors from the following life cycle stages: raw materials, manufacturing, transportation, operation, and end of life.
- **Natural Gas.** In the mixed-fuel cases, emissions from primary natural gas consumption are analyzed.

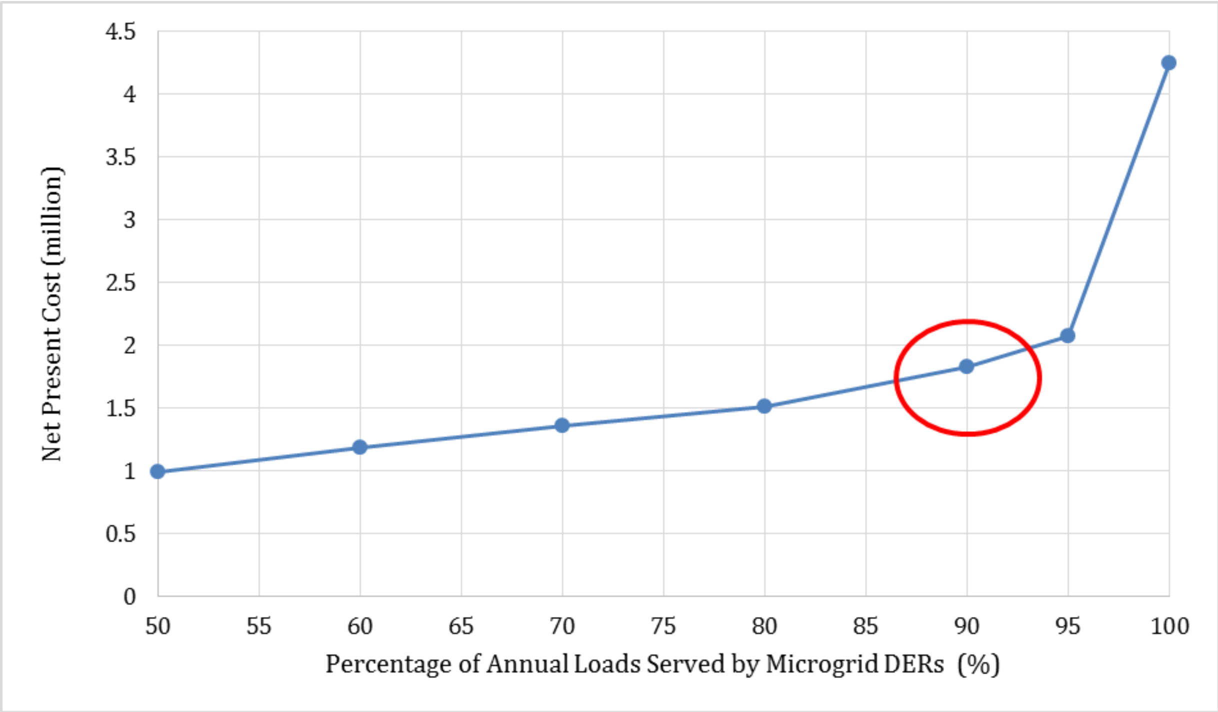
Resiliency and Excess Generation (R&EG)

In the resiliency use case, the generation and storage assets of the project are designed to maximize the microgrid's capability to island from the grid. Islanding capability is measured by the percentage of annual load that can be met by the microgrid when islanded. If cost were no object, the microgrid would ideally be able to meet 100 percent of its annual loads when islanded. However, substantially lower costs and significant functionality can still be achieved by enabling the microgrid to meet a lower percentage of annual loads.

Figure 5 shows the net present cost of generation equipment increases substantially when designing microgrids to have an islanding capability greater than 90 percent. Since solar panels do not supply a consistent amount of energy, the microgrid would not be able to meet 100 percent of the annual load without significantly oversizing both the solar generation and battery storage. The cost of oversizing these components greatly outweighs the benefits received from them, thus leading to the exponential increase in net present cost. To maximize islanding capability while avoiding the exponential increase in net present cost, all use cases were constrained to maximum islanding capabilities of 90 percent of the annual load.

23 *Annual Energy Outlook 2018*, U.S. Energy Information Administration. January 5, 2017. www.eia.gov/aeo.

Figure 5: Relationship Between Microgrid's Islanding Capability and NPV of Generation Components



Source: Energy Solutions analysis, 2017

Results by Use Case

Results by use case are summarized in Table 4. The preferred house type model (all electric or mixed fuel) for each use case is highlighted in green.

For the resiliency use case, both columns are highlighted because there is ambiguity about which scenario should be preferred. From a cost perspective, mixed-fuel homes are preferred as they can deliver the desired electrical islanding capability at much lower cost than all-electric homes. However, a major benefit of the all-electric design is that Avenue I would truly have the ability to island from all central infrastructure in the event of natural or other disasters that might compromise central gas infrastructure.

For the EBS use case, mixed-fuel homes are preferred because energy services can be delivered to Avenue I at lower cost than in the all-electric scenario. Both of the results have relatively low islanding capabilities and PV system sizes that minimally comply with the city of Lancaster's ZNE Ordinance (2 watts/ft^2). While operational natural gas costs are not included in the above NPC calculation, they are estimated to be $29,727 per year for the whole community, and thus while they will add something to the total NPC, it is not enough to favor all-electric designs.

Table 4: Results by Use Case

Design Component	RE&G – All Electric	RE&G – Mixed Fuel	EBS – All Electric	EBS – Mixed Fuel	ER – All Electric	ER – Mixed Fuel
Islanding Capability	90%	90%	30%	40%	90%	90%
PV System Size	692 kW	445 kW	255 kW	255 kW	692 kW	445 kW
Storage Size	1,629 kWh	1,482 kWh	325 kWh	325 kWh	2,418 kWh	1,482 kWh
Lifecycle Emissions (over 25 years)	4,019 mtCO2e	6,046 mtCO2e	4,303 mtCO2e	6,401 mtCO2e	981 mtCO2e	4,091 mtCO2e
Net Present Cost (NPC) or Lifecycle Cost (25 years, 5 percent discount rate)	$2.70 million	$2.70 million	$2.31 million	$2.38 million	$2.98 million	$2.69 million
Levelized Cost of Energy (LCOE)	$0.22/kWh	$0.19/kWh	$0.16/kWh	$0.17/kWh	$0.20/kWh	$0.19/kWh

Source: ZNE Alliance

For the emissions reductions use case, all-electric designs are strongly preferred. The DER sizing and islanding capability turned out to be the same as in the resiliency use case, but a different control strategy was implemented, to prefer the use of DER resources to grid electricity. This raised the NPC of the microgrid, but drastically reduced emissions. In the all-electric scenario, life cycle emissions are less than a quarter of other all-electric scenarios. The same control strategy was used in the mixed-fuel case. While these lowered emissions relative to the mixed fuel scenarios in the other use cases, the primary natural gas consumption resulted in emissions of over four times that of the all-electric design.

Hybrid Use Case

Recognizing that LCE and the City of Lancaster would ideally like to prioritize emissions reductions, energy bill savings, and resiliency in the Avenue I microgrid, the AEC project team analyzed the results from the three use cases and proposed a recommended design configuration that balances the goals of each use case. Additionally, the recommended hybrid approach accounts for the practical realities and spatial constraints of installing the proposed system at Avenue I. The recommended Avenue I microgrid is summarized in Table 5.

Table 5: Results of Hybrid Use Case

Design Component	Hybrid Use Case – All Electric
House Type	All-electric
Islanding Capability	50%
PV System Size	450 kW (6kW per home)
Storage Size	1,005 kWh (equivalent to 1 Tesla Powerwall per home)
Lifecycle Emissions	2,106 mtCO2e
NPC (25 years, 5 percent discount rate)	$2.17 million
LCOE	$0.13/kWh

Source: Energy Solutions analysis, 2017

The hybrid use case strikes a balance in cost, emissions, and resiliency, as well as the spatial considerations of the proposed Avenue I site. For more details on the technical design aspects of the Avenue I hybrid use case see the **Lancaster Advanced Energy Community Microgrid Technical Design, Control System Specification, and Interconnection Report**, described in Appendix A.

Permitting and Interconnection Opportunities

As part of the Avenue I Technical Design, the AEC project team analyzed the interconnection process for the microgrid at Avenue I. The AEC project team communicated with representatives at Southern California Edison (SCE) to provide information to LCE on the process and requirements for a fast-tracked interconnection application.

Interconnection Agreement Process

The project is a unique use case showing a cluster of single-family homes that will tie into one master meter. The development then qualifies under Rule 21 for the standard Net Energy Metering (NEM) tariff, Version 2.0. Version 2.0 guarantees compensation for surplus electricity generated for 20 years at the retail rate, but stipulates that the customer that receives compensation is on a time-of-use tariff. For the project to apply for interconnection, the applicant must submit:

- Standard NEM application for the master meter
- Single line diagram
- Plot plans

- A final inspections job card
- A completed interconnection agreement
- A completed Form 16-344 because the solar PV and storage will exceed 10kW. This is the interconnection agreement for NEM projects of less than 1 MW where there is a single meter tied into the distribution grid.

The aggregate load of the generation and storage components is sized to ensure the generation and energy storage can meet the peak load of the community. To be eligible for the Fast Track process, the generating facility must have a gross nameplate rating below 3 megawatts (MW) tied into one of three line circuits, 12 kilovolts (kV), 16kV, or 33kV. The project will be considered a commercial load because of the single-point of interconnection (the line will tie into a 12kV circuit in Lancaster).

The applicant must submit the documents listed, which initiates the interconnection review and process. After receiving documents, the distribution provider, in this example SCE, will verify the forms are correct and initiate a Fast Track evaluation. Not all microgrids will be able to fast track their interconnection request, however, after reviewing circuit lines near the site area on SCE's DERim GIS Web Map,[24] there appears to be adequate capacity on nearby circuits for the project to tie into the grid without requiring additional front-of-the-meter infrastructure. Further communication with SCE, as the project enters the development stage, will validate this and determine the circuit best suited for interconnection.

Figure 6 describes the Fast Track process and highlights the various requirements to ensure the project's interconnection to SCE's circuits is seamless and technically feasible. LCE engineers will review the electrical specifications of the microgrid development and work in tandem with developers to ensure Fast Track can be met. The Fast Track process begins with an initial review and if required, a supplemental review follows. While filling out the interconnection application, Form 14-957, the application must specify which, if any, rebate programs the applicant is applying to receive. Since the battery storage components of Avenue I's microgrid are eligible for rebates through the Self-Generation Incentive Program, the applicant must provide information about the program for which they are applying.

As there will be one point of interconnection and the project is sized less than 1 MW, the customer will pay a $75 fee for interconnection. A supplemental review may be required should the project fail any screens in the initial review. The supplemental review includes several additional electrical tests about the amount of capacity on the distribution circuit, power quality and voltage, safety, and reliability.[25] Absent the ability to Fast Track interconnection into SCE's T&D infrastructure, a detailed study of the effects of the interconnection is required. A detailed study makes the interconnection process a yearlong endeavor (compared to about a month for a fast track process). The interconnection agreement determines:

24 Southern California Edison's Distributed Energy Resource Interconnection Map. Southern California Edison. http://www.arcgis.com/home/webmap/viewer.html?webmap=e62dfa24128b4329bfc8b27c4526f6b7.

25 Choi, C. Rule 21 Generating Facility Interconnections. Southern California Edison.

- Required facilities and upgrades (atypical for Fast Track applications)
- Financial responsibility for the facilities
- Tax information required

Once the interconnection agreement is finalized, the microgrid construction begins and the customer receives permission to operate.[26] The full fast track process is described in Figure 6. Based on the AEC project team's evaluation of the Avenue I site and requirements, the presumption is that Avenue I will qualify for Fast Track.

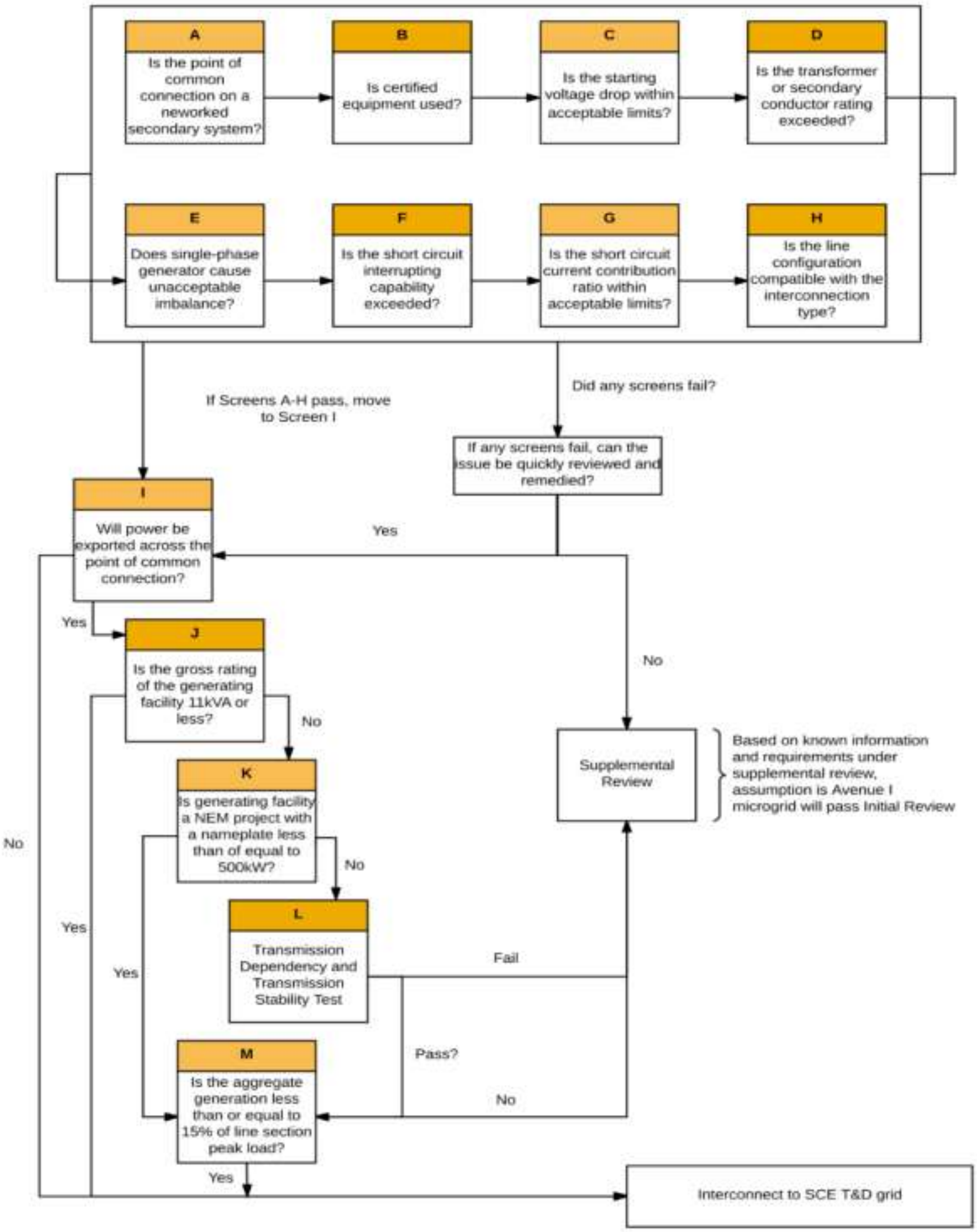
Interconnection Lessons Learned

Residential microgrids may be an increasingly attractive option as Title 24 is updated in 2019 to require all new homes to be zero-net energy, which will also require solar PV and battery storage. The Avenue I project is a model case for what a distributed future may look like. Numerous opportunities have surfaced to improve the interconnection process for similar developments and described as.

- **Streamlining the interconnection process for determining a residential microgrid tariff.** Residential microgrid projects would initially appear to qualify for virtual net energy metering (NEM-V) and net energy metering aggregation (NEMA). However, the ownership structure of the homes and metering requirements appears to disqualify the Avenue I project from eligibility. The NEM-V tariff applies to multi-family properties, with multiple meters receiving bill credits from renewable generation (such as solar panels), while the NEMA tariff is intended for single customers with multiple meters on the same property, or on adjacent or contiguous properties, to use renewable generation to serve the aggregated load behind all eligible meters. Avenue I aggregates load through a single point of interconnection and appears to rule out these tariffs. These issues may create confusion for future applicants of net energy metering programs. The process should be easy to understand to provide incentives for further interconnection of distributed energy resources.
- **Incentive or net energy metering benefits for microgrid developments in transmission-constrained areas.** The current tariffs do not account for value of distributed resources to the grid for resilience and locational price. Including these values in future tariff designs would encourage residential microgrid development. It may be less expensive for microgrids to be built in transmission-constrained areas than new transmission and distribution infrastructure. By incentivizing development near the source of consumption, whether it is through lower billing rates, an alternative rate structure, or a one-time incentive payment, the distribution system operator can save money and maximize reliability in constrained territories. IOUs can actively recruit microgrid development in areas or forecasted to expect issues with grid reliability, such as in Central Orange County resulting from the closure of the San Onofre Nuclear Generating Station.

26 SCE's Generator Interconnection Process. Southern California Edison. April 2017.

Figure 6: Fast Track Process for Interconnecting to SCE Circuits



Source: Choi, C. Rule 21 Generating Facility Interconnections. Southern California Edison.

For more information about filing interconnection applications for residential ZNE communities, please see the Residential Subdivision Permitting and Interconnection Challenges and Opportunities, described in Appendix A.

CHAPTER 3: DER Value Creation

In addition to exploring options for residential ZNE microgrid development, the team also analyzed how to maximize the value created from DER programs. Working in concert with LCE, the AEC project team developed a complex model to analyze the potential for value creation in various DER program technical configurations, and then unpacked how to best support them with sustainable and scalable partnerships between public agencies and private partners. Finally, the team designed an energy storage program with LCE to maximize value for LCE and its customers.

Community DER Valuation Framework

Objectives

The purposes of the DER community valuation framework are:

1. To develop a user-friendly valuation method and tool that analyzes DERs in a standardized yet flexible manner to accurately assess their value in dynamic market conditions.
2. To enable load serving entities (LSEs), end-use customers, and developers to comprehensively assess the impact of alternative DER programs under a variety of future wholesale power cost and ancillary service scenarios and prices, using diverse business models, technology ownership structures, and program delivery mechanisms.
3. To support developing viable business models and financial investments that will accelerate broad deployment of DERs in California and other states.

Historically, identifying applicable value streams accurately and to make direct comparisons between different DER technologies has been, at best, complicated and imprecise, and, at worst, unquantified and vague. This inability to value DERs in a standardized manner has hindered the widespread use of DERs. The project team intends and expects the DER community valuation framework will enable all stakeholders in the renewable energy economy to move forward with greater certainty regarding DER costs, value streams, business models, and program structures.

Components of Analysis

The DER community valuation framework is built on a common set of data variables, assumptions, equations, and methods that ensure a standardized approach to evaluating DER measures. The framework includes: 1) a program-level performance projection for each proposed DER measure; 2) documenting the program's energy and capacity impacts, and; 3) identifying corresponding benefit and cost impacts within a specified program context from the LSE and customer perspectives. These impacts, benefits, and costs are analyzed and quantified via a discounted cash flow (DCF) model and evaluated over the life of the DER program.

The key to the standardized valuation process is to ensure that all measures are analyzed under a common set of economic variables, using a consistent analytic method. The DCF method ensures an equitable analytic approach, which results in DER program-specific cash flows on an annual and cumulative basis over the lifecycle analysis period. The annual cash flows are then used to calculate standard economic metrics for each DER program. This standardized valuation platform is used for calculating DER value from the LSE and the customer perspectives.

In developing the DER valuation framework, a step-by-step process was devised to identify, analyze, and design technology- and service-based DER programs. This process included:

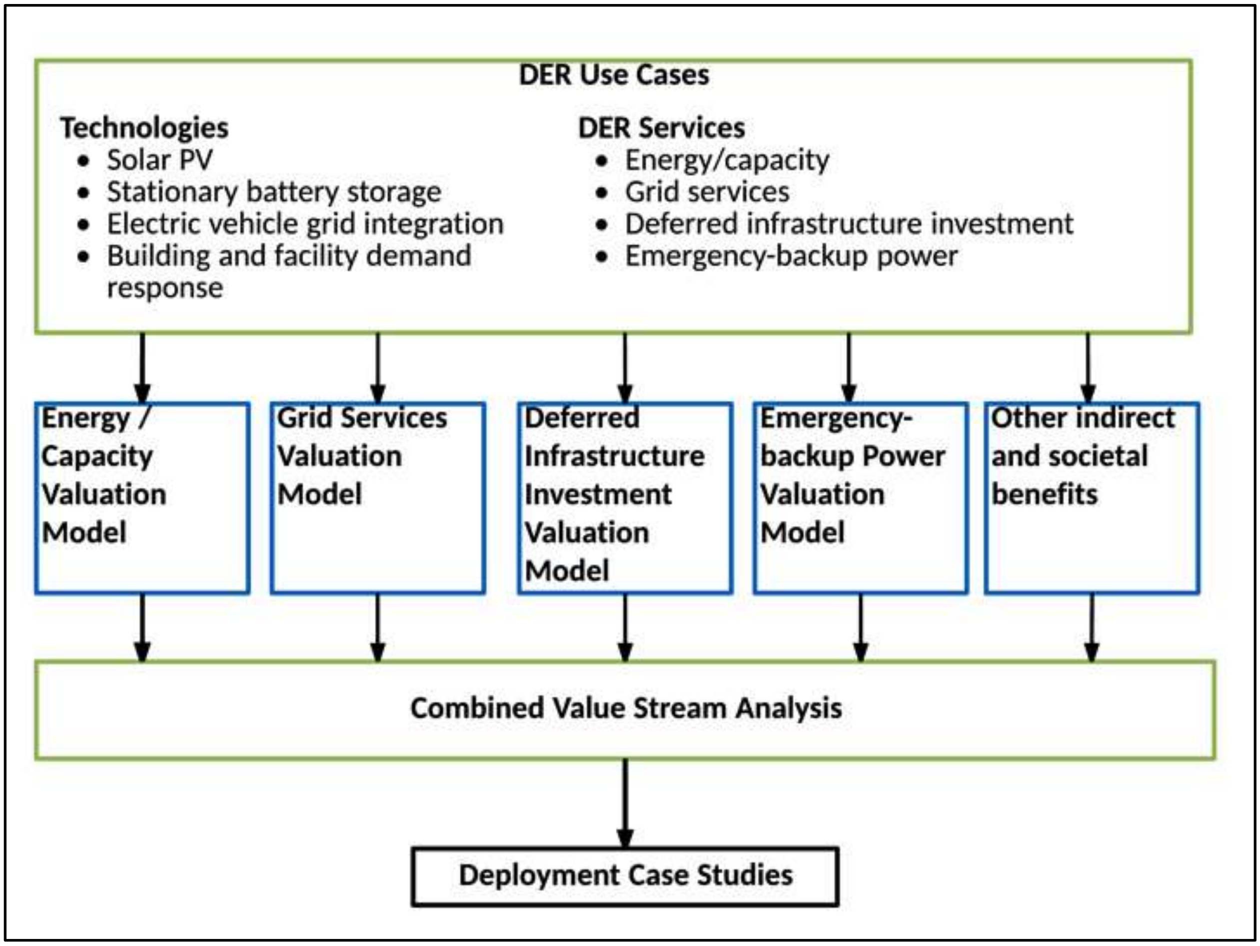
- Identifying applicable DER use cases
    - DER technologies (Solar photovoltaic (PV), solar plus battery storage systems, EV smart charging)
    - DER services (demand response)
- Identifying and analyzing applicable value streams.
- Developing business model scenarios.
- Developing program design characteristics.
- Modeling and analyzing DER technology and services:
    - Impacts
    - Costs
    - Benefits
    - Annual and cumulative cash flows
- Valuing specific DER use cases through assessing economic metrics
- Demonstrating the DER Valuation Framework via the development of DER program deployment case studies

Figure 7 illustrates this step-by-step process. The process, framework, and tools developed provide a comprehensive structure that can be easily applied to LSEs ensuring the DER program use cases are properly identified and screened, and their effects and value can be accurately analyzed to support decision-making on the design and use of high-value DER programs.

DERs and DER Use Cases

The DERs considered by this valuation framework study were selected based on their ability to provide a range of different services and value streams to LSEs in general, and to CCAs and their customers specifically. DER technologies and services selected for analysis using this valuation framework can be either in front of the meter or behind the meter, and are defined as grid-connected technology assets located on the low-voltage electrical distribution network. Examples of DERs include renewable generation sources such as PV systems, flexible loads such as integrated smart building systems, electric vehicles, and stationary battery storage.

Figure 7: Flow Chart of DER Community Valuation Methodology



Source: Olivine analysis, 2017

The Distributed Energy Resource Valuation Model (DER-VM), developed as a spreadsheet-based tool from the valuation framework, is comprised of four separate modules, each corresponding to a specific DER use case. These four use cases were selected for valuation tool development and demonstration:

- Subscriber-based local community solar
- Customer-sited solar plus stationary battery storage
- Electric vehicle smart charging and battery storage
- Customer aggregated demand response in the LCE service area

The DER valuation framework was used to develop the DER-VM, which provides consistent results that inform stakeholders on the benefits and costs, and allows for direct comparisons between DER use case options and business models. For each use case module, the analysis begins with input of common assumptions used throughout the use case analysis. LSE and end-use customer specific inputs are then accepted by DER-VM before displaying impacts, benefits, and costs related to the adoption of the specific DER program. From the impacts, benefits and costs, a discounted cash flow (DCF) analysis is applied to determine the economic metrics detailed in Table 6.

Table 6: Economic Metrics Calculated by the DER-VM

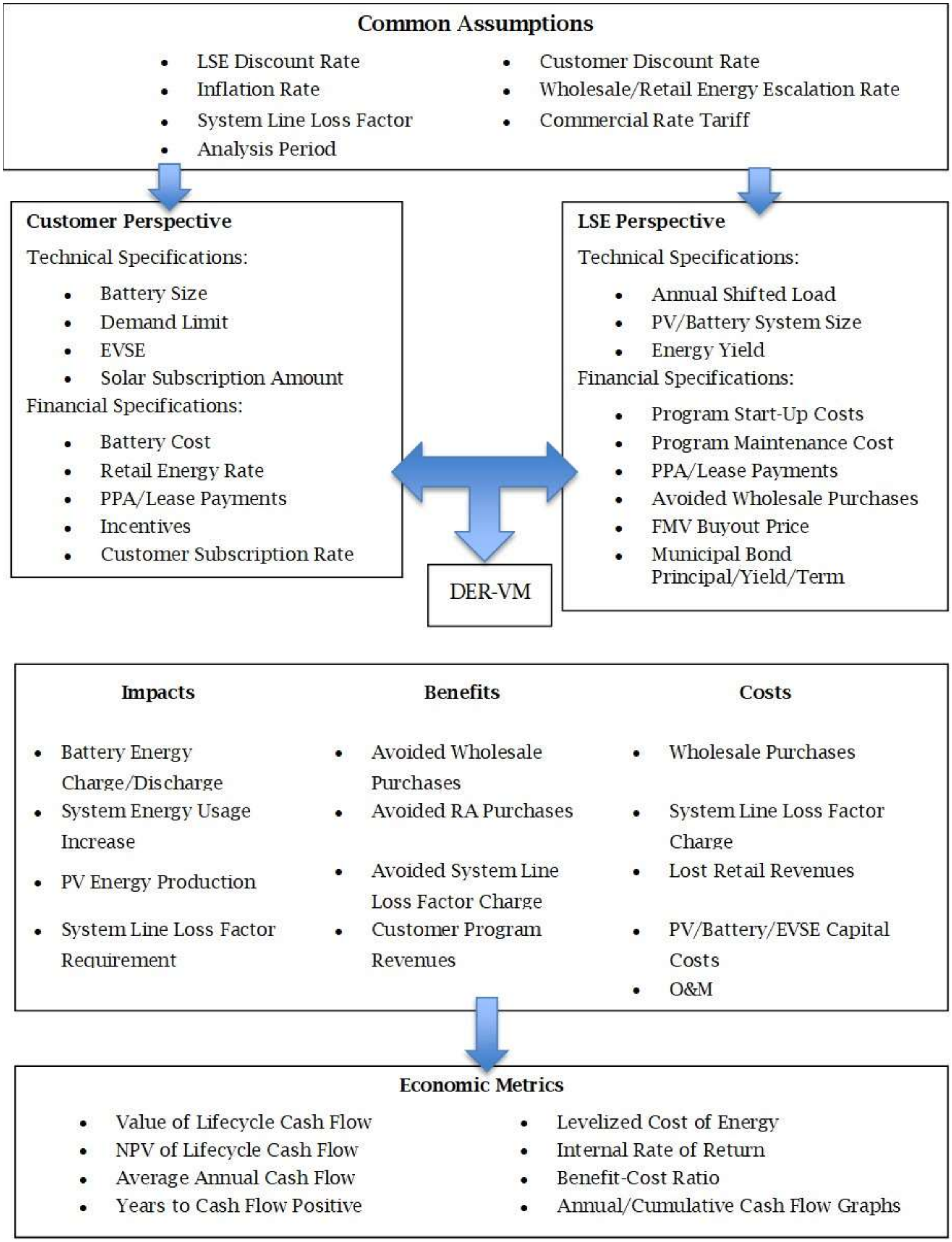
Economic Metric	Units	Description
Nominal Value of Lifecycle Cash Flow	$	Nominal sum of annual cash flows over analysis period
NPV of Lifecycle Cash Flow	$	NPV of cash flows over analysis period
Average Annual Cash Flow	$	Nominal average annual cash flow over analysis period
Years to Cash Flow Positive	Yrs.	Number of years until cash flow positive. If result reads “#N/A,” scenario does not reach cash flow positive over analysis period.
Levelized Cost of Energy	$/kWh	NPV of the unit-cost of energy over analysis period
Internal Rate of Return	%	Discount rate at which NPV of cash flows over analysis period is equal to zero
Benefit-Cost Ratio	Unitless	Discounted cash flow benefits divided by discounted cash flow costs Values > 1 = net benefit Values < 1 = net cost

Source: Olivine analysis, 2017

The metrics considered by the valuation framework provide important economic benchmarks to evaluate the feasibility of a DER resource or program. These metrics aid in the decision-making process by measuring the value of an investment in a DER resource or program. The purpose of this valuation methodology is not to calculate precise future values based on the above metrics, since the exact market conditions in the future can only be estimated. Rather, this framework provides enough information to determine whether a DER project or program is economically feasible or infeasible, a sense of the magnitude of economic value compared to the initial investment, and the likely ongoing costs of maintaining the project or program. The DER-VM economic metrics can be used to compare DER program business models for specific use cases to determine the optimal model for implementation. Additionally, the metrics can be used to compare DER programs among one another. However, as the DER-VM model was designed to screen for and optimize individual program design strategies, and to compare results against other DER program resources, it is critical that key input values be consistent across the programs (for example, expected program life, discount rates, etc.)

A simplified flow chart of the DER-VM is shown in Figure 8.

Figure 8: Flow Chart for DER-VM



Source: Olivine analysis, 2017

Value Streams

The impacts, costs, and benefits analyzed by the DER valuation framework are largely a function of the potential value streams associated with specific DERs. For example, each potential value stream has a quantifiable impact resulting from the DER implementation, and there are technology-specific costs and benefits associated with capturing that value stream. The potential value streams identified for further analysis with DER-VM were categorized as follows:

Wholesale Energy Procurement Offsets

Wholesale energy procurement offsets occur when DERs reduce system hourly energy requirements that otherwise would have to be met by procurement on the wholesale market. A major goal of many DER technologies and services is to reduce wholesale energy procurement during hours of high priced energy. Through strategic targeting of energy reductions during these high priced hours, DERs can provide significant value to LSEs as avoided costs of energy procurement. Examples of mechanisms that can be deployed to achieve energy procurement offsets include direct load reduction (through DR or distributed generation), energy arbitrage (through behavioral DR or storage), or supply-side generation.

Resource Adequacy

Resource adequacy (RA) is a contracted capacity requirement decided by the CPUC to ensure that the California ISO will have sufficient capacity reserves to meet peak load requirements reliably. System, local, and flexible RA can provide significant value, depending on the location and operating characteristics of the DER. DERs can add RA value without directly participating in the wholesale market by acting as a load-modifying or supply-side resource. In these cases, the DER supply can be incorporated into the load forecasts, which in turn determine the LSE's RA obligations.

Ancillary Services

DERs can participate in the ancillary service market, run by the California ISO, by the regulation, spinning reserve, and non-spinning reserve products. These services assist in maintaining grid frequency to the acceptable 60 hertz (Hz).

Deferred Infrastructure Investment

Targeted DERs can be used to delay or prevent costly infrastructure upgrades. Well-managed DERs can reduce the costs of integrating increased penetration of variable generation and electric vehicle charging on the distribution system. The value of infrastructure deferral will depend on the operational use and the specific location of the DER resources. DERs can prevent the necessity for new transmission lines, substations, distribution line capacity upgrades, and transformer upgrades. Demand response, solar PV, storage, EVs, and load management can contribute to potential deferrals or elimination of distribution system upgrades if they are sited and operated in a manner that relieves transmission and/or distribution congestion during high-stress periods.

Customer Value Streams

Customers have several ways to capture value streams through DERs. LSE customers can save money through reducing their energy use by participating in demand response programs (and potentially receive revenue payments from wholesale market participation), installing building energy management systems and smart technologies, installing distributed generation resources such as rooftop solar, or by a combination of these. Customers on a time-of-use (TOU) rate tariff can also save money by shifting consumption from high-price to low-price times of day through behavioral modifications, smart technologies, and energy storage systems. Finally, retail customers with a monthly demand charge based on the highest use during a month (and potentially an additional demand charge based on highest use in a specific time of day) can save money with DERs that reduce customer peak load.

Other Indirect and Societal Benefits

Outside of quantitatively evaluated value streams, there may also be qualitative benefits that may not be directly monetized by the LSE or its customers. These benefits may still serve to meet broader regulatory and societal goals. For example, qualitative value streams may be provided by greenhouse gas reductions, local air pollution mitigation, or regulatory compliance with renewable energy or storage procurement mandates.

Categories of Analysis

Throughout the valuation framework and DER-VM, value streams are evaluated and quantified in terms of their impact, benefits, and costs. A sample screenshot of a portion of the impacts, benefits, and costs sections of a DER-VM use case Pro Forma is provided as Figure 9.

Impacts

The impact analysis portion of the DER Community Valuation Framework centers on quantifying the electrical impacts of a particular DER use case directly monetized by the LSE or the customer. From the LSE perspective, three general categories were considered in the valuation framework annual energy impacts, annual aggregated resource adequacy (RA) yield, and annual avoided system line losses.

Leading impacts from the customer perspective can be defined as annual energy impacts and monthly/annual peak demand reductions.

Benefits

The benefits analysis of the DER valuation framework is designed to capture all of the benefits that are directly monetized as a result of the implementation of DER use cases from the LSE and customer perspectives. From the LSE perspective, benefits included: 1) annual wholesale energy procurement offsets value; 2) annual aggregated resource adequacy yield value; 3) annual avoided system line loss factor charges; 4) program subscriptions and shared revenue savings and; 5) increased retail revenues.

Impacts from the customer perspective are summarized as: 1) annual energy impacts and; 2) monthly/annual peak demand reductions.

Figure 9: Screenshot DER-VM Impacts, Benefits, and Costs Pro Forma

PROJECT DESCRIPTION 1(a): MW$_{AC}$ Community Solar Photovoltaic Plant/Single Axis Tracking/Wholesale PPA w/ Buyout - LCE Perspective				
IMPACTS	1	2	3	4
Annual Energy Production (MWh)	7,346	7,309	7,273	7,236
Annual Aggregated Resource Adequacy Yield	15.95	15.87	15.79	15.71
Annual System Line Loss Factor Requirement (MWh)	389	387	385	384
Annual Energy Production (MWh) (Analysis Period)	7,346	7,309	7,273	7,236
[Dummy Variable]				
[Dummy Variable]				
BENEFITS				
Avoided Wholesale Energy Purchases	$165,947	$169,246	$172,609	$176,040
Avoided Resource Adequacy Purchases	$7,440	$7,588	$7,739	$7,893
Avoided System Line Loss Factor Charges	$8,795	$8,970	$9,148	$9,330
Customer Subscriber Revenues	$756,633	$752,850	$749,086	$745,341
[Dummy Variable]				
[Dummy Variable]				
Annual Benefits	**$938,816**	**$938,654**	**$938,583**	**$938,604**
Annual Benefits (Analysis Period)	**$938,816**	**$938,654**	**$938,583**	**$938,604**
COSTS				
Annual PPA Costs	$367,298	$365,461	$363,634	$361,816
Lost Retail Revenues	$468,158	$477,462	$486,952	$496,630
Program Administration Costs	$60,000	$7,500	$7,659	$7,821
[Dummy Variable]				
[Dummy Variable]				
Annual Costs	**$895,456**	**$850,424**	**$858,245**	**$866,267**
Annual Costs (Analysis Period)	**$895,456**	**$850,424**	**$858,245**	**$866,267**

Source: Olivine analysis, 2017

Costs

The cost analysis portion of the valuation framework focuses on quantifying the costs directly related to implementing and operating DER projects from the LSE and customer perspectives. From the LSE's perspective, costs include 1) DER implementation costs (capital, installation, operations and maintenance [O&M], PPA contracts); 2) wholesale energy procurement costs; 3) lost retail revenues and; 4) incentives that are paid to customers to encourage participation in the DER program.

Costs from the customer perspective may include increased energy costs for premium services (for example, community solar), equipment purchase or lease costs, and operation and maintenance costs for any purchased equipment.

Key Findings

In the beginning of the framework development process, the DER-VM was intended to be a single spreadsheet-based module that incorporated a number of DER programs. The rationale for this originally proposed format was that it would be easier to compare the economic metrics among the programs, and to run sensitivity analyses on common economic inputs easily. Upon constructing the model, the decision was made to create separate DER program modules. The driver behind this decision was that program lifecycles often differ depending on the DER technology. Analysis periods are typically set to the expected life of the DER program, which in turn are tied to the expected life of the DER technology. Alternatively, the analysis period could include DER replacement costs and be set to multiples of the expected life of the DER. For example, solar PV is generally analyzed under a 25- to 30-year lifecycle, as opposed to battery storage, which is often analyzed under a 10-year or shorter lifecycle. For emerging technologies like electric vehicle supply equipment (EVSE), there is not yet a standard industry-accepted analysis period. Another consideration in building separate valuation modules was the spreadsheets were becoming too large and the models were taking too long to calculate results or update. As a result, the individual DER modules are more user friendly than a larger model that takes a long time to run or may even become unresponsive.

One of the key takeaways from developing the DER community valuation framework was the effect that energy and RA values have on the results. The framework used a conservative 2.5 percent annual increase in energy and RA prices for the life of the program. With energy and RA prices low, DER programs may not show the level of economic value that they otherwise would if energy and RA prices rise faster than estimated. Framework users should assess low, medium, and high scenarios for these prices to capture the full range of economic value possibilities.

Another key finding was creating a flexible framework was crucial because the value of DER programs depends on multiple variables that are site-specific. The same DER program can potentially provide different amounts of value at different sites. For example, benefits from RA value depend in part on the location of the resource. Certain areas may require capacity, resulting in higher RA value. Rate structures of LSEs and program design/operation costs are also variables that have an impact on the economic value of a program, and thus the framework must be able to adapt to these site-specific characteristics. For example, TOU periods are likely to shift in the coming few years; these impacts on LCE and customer value should be taken into consideration when analyzing and designing DER programs. “Dummy variables” were also added to DER-VM for users to incorporate any value streams that come to fruition in the future as market conditions continue to evolve, or for LSEs with different operating characteristics (for example, LSEs that own and operate the distribution system).

Consistency in the metrics used to evaluate DER programs from LSE and customer perspectives was also an important consideration. With the DCF methodology, the economic metrics used to evaluate DER programs in the framework are the same across all the use cases analyzed. The ability to see the effects of varying assumptions quickly also provides the opportunity for more granular analyses. For example, the discount rate can be varied with all other assumptions held constant and the economic metrics then update in real time.

Opportunities for Further Development

In future iterations of the framework and DER-VM, key features can be incorporated to increase its flexibility and robustness. For example, adding in additional business models to analyze evolving industry procurement practices would add to the robustness of the model. Another example would be adding a Power Purchase Agreement (PPA) business model to the customer-sited solar plus stationary storage and the electric vehicle smart charging and battery storage modules to capture this emerging procurement trend for end-use customers.

An additional opportunity for further development of the DER-VM is to enhance the modeling capabilities of managing the battery system charging schedules for the battery-related use cases. With the current iteration, the battery will charge from the grid at the soonest available opportunity, with the only constraint being keeping the facility demand below a set threshold. More wholesale procurement offset value can be extracted by directing battery charging to strictly off-peak times. This is a function of the third party model used as an input to the DER-VM, but could be built in to the DER-VM in the future.

Finally, the framework provides more robustness by linking all of the modules to aggregate the impacts, benefits, and costs of the four modules (or a subset of selected measures) to provide an LCE system impact analysis. By looking at system level impacts of a diverse set of DER programs with an LSE's service area, the LSE can have a better understanding of how DERs can work together to reduce procurement costs, rather than looking at these impacts exclusively by individual DER resource.

Using the DER Valuation model, the team analyzed a series of projects for the City of Lancaster. Some of these demonstrated a strong value proposition for Lancaster and LCE, some less so. Since concluding the analysis, the project team has been collaborating with LCE to advance the highest-value projects towards implementation. Additionally, the project team took the most value-creating elements from the DER Valuation analysis and layered them to create a compelling DER Program design for LCE and the city of Lancaster.

Projects Explored in Valuation Exercise

A number of DER projects were analyzed for LCE through the DER-VM. The following are brief summaries of the DER project use cases explored in the valuation exercise for LCE.

Subscriber-Based Local Community Solar

This use case is defined as the procurement of a 3 MW single-axis tracking solar PV system to be sited at a city-owned property to support a local community solar program. Community solar is a front-of-the-meter solar PV system that, through voluntary participation, provides energy or financial benefits or both to community members. The community solar program designed and evaluated for LCE was based on a customer subscription model, where the customer pays a modest premium for locally generated solar energy. The customer subscribes to a set amount of capacity and then purchases the amount of energy generated from that capacity reservation each month.

From LCE's perspective, implementing a community solar program has relatively neutral economic impacts during the analysis period. The potential program was designed to ensure that no net costs would be shifted to LCE or non-participating customers. This was done by setting the customer subscription rate so that LCE's economic metrics were all neutral or slightly positive. By designing the program in such a manner, all of the project and program costs would be borne by the subscribers, including the lost revenues resulting from subscribers not purchasing rate-based energy from LCE. As such, a community solar project is technically and economically viable. However, if LCE were to proceed with a program, they must be confident that a market would exist to support the premium product. As LCE's current 100 percent Smart Choice premium product has a low subscription rate, it is unlikely that such a venture would be successful in current market conditions. If LCE wanted to move ahead with a community solar offering, it may also be prudent to start with a smaller size PV system (<1 MW) to gauge demand before proceeding with a larger offering.

Tables 7 and 8 provide the DER-VM output for the Community Solar Program Use Cases from the LCE and customer perspectives, respectively.

Customer-Sited Solar Plus Stationary Battery Storage

Under Assembly Bill 2514 (Skinner, Chapter 469, 2013), CCAs must procure energy storage capacity equal to 1 percent of their annual peak load by 2020. For LCE, this equates to about 2 MW of storage capacity. For this use case, the project team evaluated adding stationary battery storage equipment at five municipal facilities with existing solar PV in Lancaster.

From LCE's perspective, the economic value of adopting battery storage is close to negligible over the analysis period. This is because batteries simply shift facility energy and demand requirements from one time to another. As a result, the volumetric energy sales from LCE to the customer do not change significantly. In fact, LCE would probably see a slight increase in energy sales from battery storage units as the round-trip efficiency of battery charging and discharging results in about a 15-20 percent increase in energy requirements related to battery use. However, this increase typically occurs during low-cost off-peak hours so the revenues from the customer stay about the same.

From the end-use customer's perspective, there is a net economic benefit over the analysis period. Much of this benefit stems from the reduction of facility demand charges. However, because of the nature of the loads that were analyzed for LCE, the optimal battery sizes were quite small, generally less than 40 kWh/40kW. This is because the peak period durations in these facilities were too long for a battery to reduce peak loads economically. While larger batteries could reduce these loads, the cost of a sufficiently large battery bank is uneconomic at current price levels. However, further investigations with battery suppliers will be undertaken to determine if newly developed shared savings business models could improve the value proposition. In addition, as battery prices continue to decline (at a rate of approximately 7 percent per year), the economics of battery systems will improve.

The analysis also found that a lease business model (and likely a PPA model as well) provided more value than a direct purchase. As a public tax-exempt entity, the city is precluded from realizing the tax advantages from the ITC and accelerated depreciation in a direct purchase model. In a lease model, however, the third-party system owner would be able to claim the tax incentives and pass them through to the city in the form of lower lease payments.

Table 7: Economic Metrics for 3 MW Community Solar Program – LCE Perspective

	CS PPA	CS PPA with Buyout	CS Bond Purchase
Nominal Value of Lifecycle Cash Flow	$158,545	$164,427	$143,285
NPV of Lifecycle Cash Flow	$147,245	$46,335	$22,637
Average Nominal Annual Cash Flow	$7,927	$8,221	$7,164
Years to Cash Flow Positive	1	1	1
Levelized Cost of Energy	$50/MWh	$55/MWh	$132/MWh
Internal Rate of Return	—	—	—
Benefit-Cost Ratio	1.04	1.16	1.00

Source: Olivine analysis, 2017

Table 8: Economic Metrics for 3 MW Community Solar Program – Customer Perspective

	CS PPA	CS PPA with Buyout	CS Bond Purchase
Nominal Value of Lifecycle Cash Flow	($978)	($1,025)	($1,725)
NPV of Lifecycle Cash Flow	$3,800	$3,837	$4,396
Average Nominal Annual Cash Flow	($33)	($34)	($58)
Years to Cash Flow Positive	—	—	—
Levelized Cost of Energy	$0.10/kWh	$0.10/kWh	$0.12/kWh
Internal Rate of Return	—	—	—
Benefit-Cost Ratio	0.78	0.77	0.67

Source: Olivine analysis, 2017

Entries labeled "—" indicate either negative cash flow through the analysis period or zero initial investment, thus IRR is not relevant.

The project team also evaluated large commercial customers for this use case, and confirmed that multiple uses out of a single battery storage bank are difficult to obtain. This is because batteries may be at a minimum state of charge due to responding to one use, leaving no capacity for additional uses. The analysis did show that the highest value stream was from demand charge management.

Tables 9, 10 and 11 provide the DER-VM output for the solar plus stationary battery program use cases from the LCE and municipal customer perspectives, respectively.

Table 9: Economic Metrics – Solar plus Battery Storage – LCE Perspective

	Lancaster City Hall	Clear Channel Stadium	City Park	Maintenance Yard	Lancaster Performing Arts Center
Battery Size	40 kWh/ 40 kW	25 kWh/ 12.5 kW	5 kWh/ 1.8 kW	10 kWh/ 10 kW	20 kWh/ 20 kW
Nominal Value of Lifecycle Cash Flow	$1,769	$1,030	$12	$307	$134
NPV of Lifecycle Cash Flow	$1,314	$771	$9	$228	$100
Average Nominal Annual Cash Flow	$177	$103	$1	$31	$13
Years to Cash Flow Positive	1	1	1	1	1
Levelized Cost of Energy	$0.28/kWh	$0.39/kWh	$0.33/kWh	$0.32/kWh	$0.30/kWh
Internal Rate of Return	-	-	-	-	-
Benefit-Cost Ratio	1.60	1.25	1.18	1.38	1.20

Source: Olivine analysis, 2017

Table 10: Economic Metrics – Solar plus Battery Storage – Customer Perspective with Direct Purchase

	Lancaster City Hall	Clear Channel Stadium	City Park	Maintenance Yard	Lancaster Performing Arts Center
Battery Size	40 kWh/ 40 kW	25 kWh/ 12.5 kW	5 kWh/ 1.8 kW	10 kWh/ 10 kW	20 kWh/ 20 kW
Nominal Value of Lifecycle Cash Flow	$19,511	$6,482	($92)	$4,355	$6,478
NPV of Lifecycle Cash Flow	$15,210	$4,476	($327)	$3,342	$4,719

Average Nominal Annual Cash Flow	$1,951	$648	($9)	$435	$648
Years to Cash Flow Positive	6	7	-	6	7
Levelized Cost of Energy	$4.00/kWh	$2.55/kWh	$22.55/kWh	$4.10/kWh	$8.78/kWh
Internal Rate of Return	18.3%	10.1%	-0.8%	16.5%	12.4%
Benefit-Cost Ratio	1.41	1.19	0.91	1.36	1.28

Source: Olivine analysis, 2017

Table 11: Economic Metrics – Solar plus Battery Storage – Customer Perspective with Lease

	Lancaster City Hall	Clear Channel Stadium	City Park	Maintenance Yard	Lancaster Performing Arts Center
Battery Size	40 kWh/ 40 kW	25 kWh/ 12.5 kW	5 kWh/ 1.8 kW	10 kWh/ 10 kW	20 kWh/ 20 kW
Nominal Value of Lifecycle Cash Flow	$30,954	$12,257	$972	$7,216	$12,200
NPV of Lifecycle Cash Flow	$27,196	$10,756	$849	$6,339	$10,712
Average Nominal Annual Cash Flow	$3,095	$1,226	$97	$722	$1,220
Years to Cash Flow Positive	1	1	1	1	1
Levelized Cost of Energy	$1.78/kWh	$1.27/kWh	$9.13/kWh	$1.83/kWh	$3.46/kWh
Internal Rate of Return	-	-	-	-	-
Benefit-Cost Ratio	2.65	1.93	1.55	2.54	2.60

Source: Olivine analysis, 2017

Electric Vehicle Smart Charging and Battery Storage

The city has a network of Level 2 EV chargers that are a mix of "dumb" and "smart" chargers. Smart chargers typically respond to time-of-use tariffs, demand response events, or other grid signals, and are cognizant of individual driver preferences for state of charge and timing of charge. There are more than 20 public charging stations throughout the LCE service area. This use case analyzed a smart charging strategy or stationary battery storage at city EV charging stations that are separately metered from the rest of the facility. (Notably, "dumb" chargers can be retrofitted for "smart" operational capabilities with a relatively low-cost add-on module.) The use cases evaluated the potential impacts of these strategies on demand charge reduction versus a business-as-usual scenario.

From LCE's perspective, the economic value of adopting a smart charging strategy or battery storage system is negligible during the analysis period. Similar to the previous use case, smart charging and battery storage shift load from one-time period to another, and are largely neutral in terms of energy consumption – except for the battery energy storage's conversion efficiency losses. The additional energy usage results in a negligible incremental cost increase as the additional energy is being consumed at off-peak periods when wholesale power costs are low. The analyses showed very similar economic values to LCE for the battery storage and smart charging technology options. Battery storage, however, does have the benefit of supporting LCE's storage mandate requirements.

From the end-use customer perspective, both technologies can provide significant savings from demand reductions. If the customer already has a smart charger, then employing a strategic smart charging strategy has superior economic value compared to a battery storage system. However, if there is an existing "dumb" charger, then the battery storage technology option will provide the highest value to the customer. The capital cost of procuring or upgrading EVSE(s) capable of implementing a smart charging strategy is a key factor at the city facilities evaluated. However, the increasing adoption rate of EVs implies potential for greater use of EVSE and more opportunities to manage demand charges through smart charging and battery storage strategies.

The use cases evaluated used available data and represented unique charging situations. The City Hall station is a free charging facility with three J-1772 Level 2 EVSE and two Tesla-only charging units. The second station evaluated was at the Metro Link station, which just recently opened to the public and has not been operational long enough to establish a consistent use pattern. With more than 20 charging stations in its service area, and more likely to come, this DER strategy has the potential to provide customers with lower charges on their electric bills, which could translate into lower costs to charge EVs, at little or no cost to LCE.

Tables 12 through 14 provide the DER-VM output for the EV charging use cases with a 30 percent demand reduction target from the LCE and City Hall municipal customer perspectives, respectively.

Table 12: 30 Percent Demand Reduction at City Hall EV Charging Station – LCE Perspective

	EV Smart Charging	EV Stationary Storage
Demand Limit / Battery Size	30%	30 kWh/30 kW
Nominal Value of Lifecycle Cash Flow	$28	$9
NPV of Lifecycle Cash Flow	$21	$7
Average Nominal Annual Cash Flow	$3	$1
Years to Cash Flow Positive	1	1
Levelized Cost of Energy	$0.08/kWh	$0.02/kWh
Internal Rate of Return	-	-
Benefit-Cost Ratio	1.17	1.07

Source: Olivine analysis, 2017

Table 13: 30 Percent Demand Reduction at City Hall EV Charging Station – Customer Perspective with Direct Purchase

	EV Smart Charging	EV Stationary Storage
Demand Limit / Battery Size	30%	30 kWh/30 kW
Nominal Value of Lifecycle Cash Flow	$4,883	$1,759
NPV of Lifecycle Cash Flow	$2,805	$1,466
Average Nominal Annual Cash Flow	$488	$176
Years to Cash Flow Positive	8	4
Levelized Cost of Energy	$9.04	$3.36
Internal Rate of Return	7%	1%
Benefit-Cost Ratio	1.16	1.09

Source: Olivine analysis, 2017

Table 14: 30 Percent Demand Reduction at City Hall EV Charging Station – Customer Perspective with Battery Lease

	EV Stationary Storage
Demand Limit / Battery Size	30 kWh/30 kW
Nominal Value of Lifecycle Cash Flow	$2,393
NPV of Lifecycle Cash Flow	$603
Average Nominal Annual Cash Flow	$239
Years to Cash Flow Positive	9
Levelized Cost of Energy	$4.81/kWh
Internal Rate of Return	0%
Benefit-Cost Ratio	1.02

Source: Olivine analysis, 2017

Customer Aggregated Demand Response in the LCE Service Area

This use case for LCE was defined as a day-ahead DR program demonstrating the capability of aggregating customer facilities to provide wholesale grid services. The use case was designed as a technology-neutral program, and simply models financial impacts to the LSE and customers. The services provided through the DR program include strategic energy reduction and system RA capacity.

The case studies examined illustrate the potential business cases for large commercial/industrial aggregation versus a small/medium business customer aggregation for a demand response program. A program involving only small/medium business in the Lancaster-designated Business Boulevard area may not have enough facility load to justify a large-scale demand response program. Even with full customer participation, the RA quantity available for DR is only 0.1 MW, and that number may decline as RA hours shift towards later in the day in future years. The business boulevard use case was barely revenue-neutral for LCE, even with no equipment costs and a low annual program cost. This suggests that it is difficult to design a financially viable demand response program that is centered on customers with mostly low annual loads, unless there is a large total aggregation and the incremental cost per customer is minimal.

In contrast, a program with the top 20 customers may be profitable for LCE assuming annual program costs of $25,000 per year, fewer dispatched events, and a potential slight change in the demand charge rate structure. Part of this discrepancy is that the retail energy rate for smaller customers is higher because larger customers pay higher demand charges. However, additional analyses are ongoing regarding the rate shifts that may be required to make up for a loss in demand charge revenues due to the DR program option. Even if larger customers are more difficult to register per customer, the load reduction potential of larger customers can be higher by more than an order of magnitude.

The value of DR from the LSE perspective is highly sensitive to program costs, enrollment rates, loss in demand charge revenue, and resulting net revenue assumptions. A low trigger price, as was the case for the business boulevard case study, can lead to significant LSE savings if retail energy rates are low during high-priced hours in the market. However, if time-of-use periods change and evening hours become more expensive at the retail level, the LSE savings may diminish greatly. The avoided energy procurement value may be significantly lower if there are no heat waves or generation shortages. The RA value for DR resources will be more significant if there are fewer dispatched events or if the LSE is short on procurement and must pay premium RA prices. A large customer program may be fully sustaining on RA value alone, while a smaller aggregation depends on market revenues to overcome project-related costs.

The DR use cases show that there is significant value to be realized if programs are designed and implemented to generate significant revenue for program participants, while minimizing inconvenience or productivity to customers. The project team’s lead consultant for the valuation model, Olivine, Inc., is an industry leader in demand response and will be available to assist LCE in the design, implementation, and management of a DR program that targets high-priced wholesale energy procurement offsets and RA value. In the context of a potential Phase 2

AEC initiative, Olivine will also be available to assist in designing programs targeted to different customer segments ranging from large commercial and industrial, to small and medium businesses, and eventually residential customers as well.

Tables 15 and 16 provide the DER-VM output for the Demand Response Use Cases for LCE's Top 20 customers and an aggregation of the boulevard customers from the LCE and City Hall municipal customer perspectives, respectively.

Best Practices in Public/Private Partnership Development

Public/Private partnerships leverage the best of what each sector has to offer. Public agencies can bring knowledge of community needs, the ability to unite diverse stakeholder groups, low-cost capital, and potential access to large aggregations of residents. Private partners bring efficient value propositions, technical knowledge and expertise, and the ability and resources to scale successful programs. Together, they can unlock value-creating, scalable, and smart programs.

The AEC project team examined several characteristics of Public/Private Partnerships. First, the potential for value creation was explored with a focus on how stakeholder incentives could be aligned to maximize value and enhance program outcomes. Three types of programs were examined in context of value creation and variability: *incentive, enrollment, and shared value.*

Table 15: Economic Metrics – Demand Response Use Cases – LCE Perspective

	Top 20	The BLVD
Value of Lifecycle Cash Flow	$19,241	$5,368
NPV of Lifecycle Cash Flow	$11,987	$2,117
Average Annual Cash Flow	$1,924	$537
Years to Cash Flow Positive	5	7
NPV of Project-Related Costs	$0	$0
NPV of Total Costs	$236,552	$32,685
NPV of Benefits	$248,539	$34,802
NPV of MWh	5	187
Levelized Cost of Energy	$0.00/kWh	$0.00/kWh
Internal Rate of Return	31.8%	11.3%
Benefit-Cost Ratio	1.05	1.06

Source: Olivine analysis, 2017

Table 16: Economic Metrics – Demand Response Use Cases – Customer Perspective

	Top 20	The BLVD
Value of Lifecycle Cash Flow	$10,353	$3,050
NPV of Lifecycle Cash Flow	$9,113	$2,685
Average Annual Cash Flow	$1,035	$305
NPV of Annual Costs	$0	$0
NPV of Annual Benefits	$9,113	$2,685
NPV of kWh	26,289	14,107

Source: Olivine analysis, 2017

Incentive

Incentive programs sponsored by public agencies are perhaps the most ubiquitous of program types examined. In an incentive program, funds are provided by a public agency to shift the value proposition of a decision maker toward a more energy efficient technology or a DER. Generally, incentive programs involve a finite engagement between stakeholders: an end user redeems an incentive, works with a public agency or private partner to deploy the intervention, and then continues to maintain the intervention independently.

Benefits of Incentive Programs

Incentive programs are relatively simple to implement, as a public agency simply has to make funds available to end customers. While incentives can take the form of tax rebates, incentives upon purchase, or incentives provided through a partnership with a private partner, in each form, the provider has minimal avenues of engagement once the incentive is redeemed. This is the greatest strength of incentives – they can be extremely simple for a public agency to implement and are an excellent option when resources are constrained.

Drawbacks of Incentive Programs

What makes incentives an ideal choice when program administrator resources are constrained is exactly what can create drawbacks. Once the end user redeems the incentive, the public agency generally has no ongoing role. Most or all of the responsibility for optimization of program outcomes then falls in the hands of the end user. While this is appropriate in instances where the end user is the only stakeholder with the ability to optimize program outcomes (as in the case of an EV purchase described below), this can have tremendous downsides as well.

For example, consider the case of a utility program designed to lower residential loads by providing incentives for refrigerator upgrades. If an end user redeems an incentive for an efficient refrigerator, the public agency benefits if the end user replaces the old, inefficient refrigerator with the new purchase. However, the end user may choose to move the old refrigerator to the garage, increasing load and creating the opposite effect than what was intended. With this typical incentive program structure, the public agency's role ends with incentive redemption (unless contractually stipulated otherwise), and this role may significantly limit the agency's ability to achieve the desired outcome (energy use reduction).

Best-Fit Programs for Incentives

Because of the simplicity of implementing, this type of program design is best for situations in which resources are constrained, or with technologies with little opportunity or benefit for multiple stakeholders to cooperate to ensure best performance. As the end user retains all control over program outcomes, a best-fit program would be one that only required engaging end users to ensure success. One example of an incentive program where design is aligned with program objectives is the Sonoma Clean Power (SCP) Drive Evergreen program (Table 17).

Table 17: Incentive Example – Drive Evergreen with Sonoma Clean Power

Sonoma Clean Power's Drive Evergreen Program		
Category	Incentive	
Description	SCP partnered with local dealerships to offer SCP customers a dual discount: a direct incentive for EV purchase from SCP and a discount on purchase price from the dealer	
End User *(EV buyer)*	Initial Role	Purchase car, redeem incentives
	Operational Responsibility	Driving habits, maintenance ensures vehicle efficiency and performance are maximized
Private Partner *(Car dealer)*	Initial Role	Offer vehicle discount
	Operational Responsibility	No ongoing role
Public Agency *(Sonoma Clean Power)*	Initial Role	Offer financial incentive
	Operational Responsibility	No ongoing role

Source: https://sonomacleanpower.org/your-options/evergreen/, accessed 11/12/2017

Enrollment

The second type of program explored is one in which a customer enrolls in a particular service provided by the public agency, generally in concert with a private partner. The customer agrees a set fee in exchange for a set outcome or service. This is essentially the opposite of the incentive structure from a value volatility perspective, as the responsibility for ensuring that value is created falls into the hands of the private partner and/or the public agency sponsoring the program.

Benefits of Enrollment Programs

Enrollment programs can be very effective when little ongoing engagement is required from the end user. As the responsibility for optimizing value creation is in the hands of the private partner or the public agency, the end user can be uninformed or even absent without affecting program outcomes.

Downsides of Enrollment Programs

An inverse of the benefit, as end users pay a fixed price for program participation, they do not share in any of the value volatility, and thus have no incentive to optimize program outcomes over time.

Best-Fit Programs for End-User Enrollment

Ideal programs for the enrollment structure are ones in which the responsibility for any ongoing operations is controlled by the private partner or the public agency. Accordingly, the enrollment structure is well suited for scenarios when ongoing operations are sufficiently complex that the end customer is effectively prevented from successful optimization and one of the other stakeholders must assume responsibility.

One example of this program design is local green tariffs like the Marin Clean Energy (MCE) Local Sol program (Table 18). To support the Local Sol option for end users, MCE partners with renewable developers to create local generation projects. To access this near-zero carbon electricity, MCE customers enroll in the "Local Sol" tariff, priced at a 14.2 cents per kWh, approximately twice the price of MCE's base rate. While MCE and the private partner (in this case a solar developer) manage the solar installation to ensure optimum operations, end users participate simply by enrolling and paying the fixed additional rate.

Table 18: Enrollment Example – MCE's Local Power Tariff

<table>
<tr><th colspan="3">Marin Clean Energy's Local Sol Program</th></tr>
<tr><td>Category</td><td colspan="2">Enrollment</td></tr>
<tr><td>Description</td><td colspan="2">MCE partners with local renewable developers by offering a feed-in tariff to purchase the electricity generated by prospective projects. The feed-in tariff is directly tied to the price of electricity charged to customers – 13.9 cents per kWh (plus a .04 cent administrative fee) who enroll in the premium Local Sol tariff. Projects that have been funded to date include a landfill gas-to-energy project at the Redwood Landfill, solar projects on rooftops at the airport, shopping plazas, and a solar installation on a brownfield at the Richmond Chevron Refinery (in process).</td></tr>
<tr><td rowspan="2">End User
(Ratepayer)</td><td>Initial Role</td><td>Enroll in tariff</td></tr>
<tr><td>Operational Responsibility</td><td>No ongoing role after enrollment</td></tr>
</table>

Private Partner *(Solar developer)*	Initial Role	Build and operate renewable project
	Operational Responsibility	Opportunity to project recover costs through efficient operations
Public Agency *(MCE)*	Initial Role	Market to and enroll customers, ensure pipeline of renewable projects aligns with customer demand, oversee renewable project development and operation
	Operational Responsibility	Need to ensure that both customer and developer value propositions are satisfied

Source: https://www.mcecleanenergy.org/100-local-solar/, accessed 11/15/2017

MCE's Local Sol program is an excellent example of an environmentally beneficial program that is most appropriate for the straightforward enrollment program design. As end users, in this case, Local Sol tariff enrollees, are not in a position to impact the efficient performance of the solar developments, there is no need to reward them for marginal gains in efficiency. Instead, paying a flat rate per kWh for electricity is appropriate given the nature of their participation.

Shared Value

The third revenue model is the shared value model, in which all stakeholders share the program's value volatility to optimize performance. The shared value model can take various forms. In many cases, the technology supplier (often the private partner) accepts an ongoing stream of future shared savings as payment for the technology installation, rather than an upfront payment. This ensures that the private partner is only paid if the program is successful in creating value. In other structures, private partners receive an ongoing share of variable performance benefits, depending on the value created.

Benefits of Shared Value Programs

Stakeholders that receive a share of program savings are incentivized to ensure that value creation is optimized. In programs that require engagement from the three stakeholder types (public agencies, private enterprises, and end-use customers) to ensure optimal performance, a shared savings model with inclusive participation of each stakeholder can ensure that the program maximizes value.

Upfront program financing can be a barrier for many end users and public agencies. By using shared savings payment instead of upfront payment, many agencies and customers can move ahead with implementing value-creating efficiency or DER installations with minimal or no requirements for upfront capital. By overcoming the barrier of securing upfront funding, this design unlocks many opportunities.

Downsides of Shared Value Programs

Shared savings programs are complicated to administer and to ensure appropriate distribution of value created. It is very important that clear contracts be in place to specify how value will be delivered under various performance scenarios. For the value of savings to be monetized, there must be a pre-intervention baseline in place that all parties agree upon. While this sounds simple in practice, it can be fraught with challenges. One notable challenge is aligning on a method to incorporate the impact of non-program interventions that impact performance. For example, if energy storage is installed to mitigate demand charges, and the installer plans to be paid by an ongoing portion of demand charge savings, all parties must be clear on the implications of other efficiency measures (for example, a more efficient HVAC system).

Best-Fit Programs for Shared Value Structure

The most appropriate programs for shared value are those that require ongoing engagement by all parties to optimize benefits, or ones in which upfront capital is a barrier to program implementation. As long as the program outcomes are reliable enough to secure financing (either external or from private partners), the shared value model can be highly effective. Table 19 highlights a capital-intensive application – energy storage – in which a no-money-down shared savings model has been implemented by the manufacturer's "Power Efficiency Agreement" program structure. In this case, the solution provider – Green Charge Networks (now owned by Engie, a large French utility) – has the deep pockets required to finance tens of millions of dollars of energy storage for installations that may have longer payback periods.

Table 19: Share Value Example – Green Charge Networks

<table>
<tr><th colspan="3">Green Charge Networks' Power Efficiency Agreement</th></tr>
<tr><td>Category</td><td colspan="2">Shared Value</td></tr>
<tr><td>Description</td><td colspan="2">Green Charge Networks installs energy storage at a customer site and then manages ongoing maintenance and operations. In return, Green Charge Networks takes a portion of energy bill savings for a set period.
These installations can be in partnership with the local utility (such as in the case of the energy storage installation at the Lancaster Museum of Art & History). However, utility participation is not necessary for the program.</td></tr>
<tr><td rowspan="2">End User
(System Host)</td><td>Initial Role</td><td>Sign up with Green Charge Networks, potentially through a utility co-marketing arrangement</td></tr>
<tr><td>Operational Responsibility</td><td>Collaborate with Green Charge Networks if necessary to ensure effective operations are maintained (in this case, site host role is minimal as storage operations are automated)</td></tr>
<tr><td rowspan="2">Private Partner
(Green Charge Networks)</td><td>Initial Role</td><td>Install storage and solar</td></tr>
<tr><td>Operational Responsibility</td><td>Optimize system once operating</td></tr>
<tr><td rowspan="2">Public Agency
(Local Utility)</td><td>Initial Role</td><td rowspan="2">Optional: can partner to provide customer outreach support, potential other source of financing.</td></tr>
<tr><td>Operational Responsibility</td></tr>
</table>

Source: http://www.greencharge.net/business-government/savings/, accessed 12/1/2017

DER Program Proposal

By taking the areas of highest value creation from the DER valuation model and layering them, the AEC project team created a proposed DER program to be implemented in partnership with LCE. The program, known as the Lancaster "Green District," positions LCE as a business partner with large, commercial, and industrial customers, and creates positive revenue streams for LCE and its customers.

Program Overview

The program combines two elements, a building energy management system to reduce peaks and lower building load, and a solar and battery storage deployment. These elements work together to reduce demand charges and manage loads.

Key Insight

Building multiple value streams for battery storage has created much excitement among storage program designers. While multiple value streams are possible in certain contexts, however, in many situations they require having separate load allocated for each purpose. For instance, if a battery is to be used primarily for demand charge mitigation, it must have capacity allocated to manage demand charges on a daily basis. While it could potentially be used for frequency regulation during off-peak hours, it would not be able to provide back-up power reliably in the case of grid outages, as the outage could occur when the charge is depleted after demand charge mitigation. Given this, much consideration must be given to where multiple value streams can be derived from the same energy storage capacity.

The team reviewed many options. Ultimately, after assessing load profiles for large users, the team found many users with on-premise load peaks that coincided with system load peaks. By mitigating loads and discrete LCE customers, the batteries could be used to offset SCE demand charges and reduce system load peaks during SubLAP price spikes, which require LCE to procure costly electricity when under-procured. Figure 10 demonstrates one such customer cost scenario.

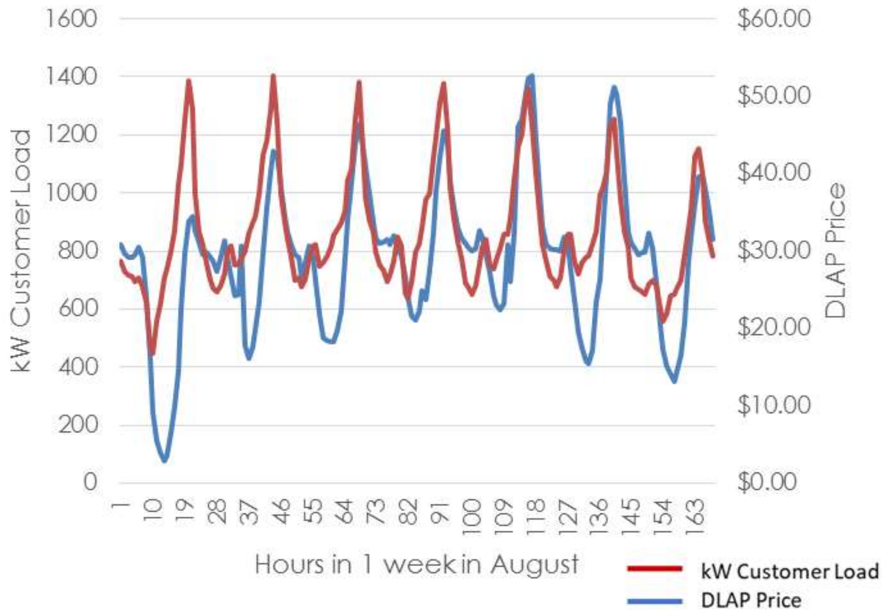
Essentially, by targeting only customers with coincident demand peaks, dual value streams can be achieved.

Enrollment

The team has designed a Green District enrollment process together with Lancaster Choice Energy. Once eligible customers have been identified and a clear value proposition has been outlined for each customer, the AEC project team will support LCE in initial outreach. Multiple steps are undertaken to verify eligibility and customer willingness to participate (Figure 11).

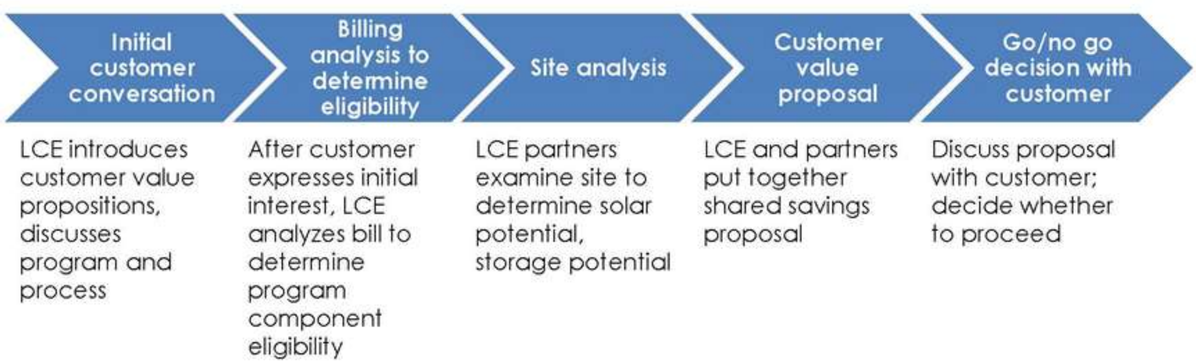
By ensuring customers are enrolled with full knowledge of the value potential of the program, program outcomes will be optimized.

Figure 10: DLAP Price Coincidence with Large User Load Peaks



Source: ZNE Alliance analysis, 2017

Figure 11: Green District Enrollment Process



Source: ZNE Alliance analysis, 2017

Next Steps

Two efforts are under way to ensure successful rollout of the DER program. First, the AEC project team is in conversation with energy storage providers to identify an appropriate partner to support the team with storage installation expertise. Ideal partners will have experience with major commercial and industrial installations and will be able to implement a shared savings approach. Additionally, private storage partners must be willing to engage in a long-term partnership with the city of Lancaster and LCE.

Second, the AEC project team is analyzing the load profiles of the largest 50 LCE customers to understand which would be good candidates for the program. From these customers alone, the project team estimates that there is up to 1 MW of coincident peak load that could be mitigated with battery storage. Removing 1 MW of load during LCE system peaks could save up to $175,000 annually in procurement costs. Once appropriate candidates have been identified, the AEC project team, together with LCE, will begin outreach to these large users. The AEC project team plans to have multiple signed contracts for storage by the conclusion of the project.

CHAPTER 4:
Benefits, Next Steps, and Conclusion

AEC Project Benefits

The benefits created by the AEC project are widespread. This AEC project will have significant effects on the City of Lancaster, and the scalable toolkit developed by the team provides resources for planning similar AEC projects that have the potential to benefit other communities in California and other states.

Benefits to the Lancaster Community

Benefits created during the AEC project are categorized by primary recipient and summarized.

- **Benefits to Residents of Lancaster:** As a not-for-profit entity, LCE uses any leftover revenue after costs to either repay the city of Lancaster for formation costs or increases programs available to customers. Either way, LCE passes any gains either directly to the city or to residents of Lancaster. As the "Green District" program is designed for Lancaster Choice Energy to save on procurement during high priced periods, the residents of Lancaster should ultimately reap the benefits of lower electricity tariffs. The Lancaster Housing Authority plans to use the housing design and energy infrastructure of the Avenue I development for all city-sponsored housing developments. The Lancaster Housing Authority estimates that these could be applicable to six or more communities during the next ten years, or about 1,000 homes. This means that 1,000 Lancaster families have the potential to reap the benefits of the Avenue I homeowners – lower energy bills, a cleaner environment, and greater energy resiliency. Lancaster has set the challenging goals of becoming the first zero-emission city in California. The GHG emissions reductions achieved through AEC project work will support the city in achieving this ambitious goal, and also create lower energy costs and improve public health outcomes for city residents.
- **Benefits to Residents of the Avenue I development:** Residents of the Avenue I affordable housing development will benefit from greater energy resiliency, potentially at a lower long-term cost. The mandate for the Avenue I community developers is to produce ZNE homes at a relatively affordable price for homebuyers – $350,000 or less per home. Under the microgrid design developed by the AEC project team, Avenue I homebuyers receive an affordable house equipped with near-ZNE solar PV energy generation and battery energy storage. Homeowners will have a lower energy bill – a benefit that extends for the 25 plus year lifetime of the PV panels – and have more electricity resiliency in the event of a grid outage. The Avenue I project demonstrates that innovative energy developments in residential housing can be distributed across all income levels.
- **Benefits to LCE:** The AEC project will reduce LCE's system peak load by approximately 1 MW, which creates procurement savings of up to $175,000 annually. As discussed, LCE is required to procure enough storage to cover 1 percent of peak load. Storage procured

through the “Green District” program and through the Avenue I microgrid will support Lancaster Choice Energy in achieving this goal.
Additionally, the “Green District” and the Avenue I microgrid have the potential to create curtailable load for demand response. An additional benefit of curtailable load is that it can be used to satisfy RA requirements. If RA value continues to rise, as many analysts predict, this could become a valuable asset for LCE.

- **Grid Benefits:** The distributed energy resources program and the Avenue I microgrid project result in reduced system load spikes and strengthen the grid. Additionally, both have the potential to produce curtailable resources that could be used by a demand response program. These resources could be used at a California ISO-level demand response program or a program instituted by LCE. These benefits will be further amplified by adopting Avenue I energy management strategies and the construction design in the Lancaster Housing Authority’s other developments. Scaling the Avenue, I microgrid design within city limits should further reduce system load spikes and strengthen the grid.
- **Benefits to California:** The Lancaster AEC project reduces GHG emissions, which will help the state achieve its emissions reduction goals. The scalable toolkit created has the potential to scale the impacts described above to many communities in California.

Potential Benefits of a Scalable Toolkit

Throughout AEC project work, the team kept a key project objective in mind – transforming AEC project work into tools that could be adopted by other communities looking to achieve similar outcomes. To organize and make this available to stakeholders from other communities, the team is creating a website database which will include all relevant deliverables, as well as instructions for how to deploy them to create advanced energy communities and discussed in the next section.

As other California communities can leverage the tools and frameworks developed during this project, all of the benefits described have the potential to be scaled significantly. To ensure that the potential benefits of the ZNE toolkit created throughout the AEC project are realized, a detailed information and technology transfer plan has been developed.

Next Steps

The AEC project team has outlined a comprehensive awareness and engagement plan to ensure the tools and frameworks developed in the Lancaster AEC Project are implemented broadly by other communities.

The team will create a website dedicated to the Lancaster AEC project and related ZNE tools. This site will include the AEC project background, introductions and explanations of the deliverables developed, and links to the deliverables.

In addition to an accessible on-line database, the AEC project team will continue using conferences and industry events to promote AEC project findings. The team already has discussed AEC project work at several workshops and conferences, including ACEEE and the

CCA summit, and has additional engagements identified. In addition, the ZNE Alliance is a key partner in the California Opportunities for Procurement (Cal-OP) initiative funded by the California Energy Commission, which will align major municipal and other (public and private) institutional purchasers of DERs and energy efficiency with best-in-class technologies and strategies to accelerate DER use and GHG reduction. The valuation, program, and policy frameworks developed in the Lancaster AEC project will be embedded throughout the Cal-OP program, in collaboration with Lawrence Livermore National Labs, Energy Solutions, Prospect Silicon Valley, CalCEF, Ecomedes, and other Cal-OP program leads.

The benefits of this AEC project in developing microgrids in residential communities and optimizing the use of DERs, are clear to the Lancaster AEC project team and the Lancaster community. The AEC project team intends these benefits will be widely shared throughout the state of California and beyond.

Conclusion

The Lancaster AEC project supported the City of Lancaster in its role as a leader of communities that are responding proactively to the challenges posed by human-caused climate change. Thanks to City of Lancaster leadership that understands the business, human, and environmental case for DERs and renewable microgrids, the city is positioned at the leading edge of this movement. The City of Lancaster is now using its Lancaster Choice Energy authority to advance energy technologies and policies broadly in partnership with other communities in the Los Angeles Basin. Each community that adopts the solutions developed during this AEC project, and pioneered by Lancaster, further builds momentum for ZNE solutions, and paves the way for adoption by other communities. Through widespread uptake of these value-creating solutions, the AEC project team is dedicated to ensuring that California will achieve its clean energy and climate goals.

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GLOSSARY

Term	Definition
DCF (Discounted Cash Flow)	Discounted cash flow is a way of finding out whether a capital investment is worth making. Using the Net Present Value method, income expected from the asset during each year of its future life is discounted, specifically reduced, to allow for the delay in receiving that income, using an interest rate (discount rate) based on the cost of capital. If the total of these discounted annual returns is greater than the capital sum needed to buy the asset now, the investment may be considered profitable.
DR (Demand Response)	Providing wholesale and retail electricity customers with the ability to choose to respond to time-based prices and other incentives by reducing or shifting electricity use, particularly during peak demand periods, so that changes in customer demand become a viable option for addressing pricing, system operations and reliability, infrastructure planning, operation and deferral, and other issues.
EPIC (Electric Program Investment Charge)	The Electric Program Investment Charge, created by the California Public Utilities Commission in December 2011, supports investments in clean energy technologies that benefit electricity ratepayers of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company.
EVSE (Electric Vehicle Supply Equipment)	The charging equipment used to supply an electric charge on an electric vehicle battery.
HOA (Homeowner Association)	A private association formed by a real estate developer with the purpose to govern a community’s covenants, conditions, restrictions, and by-laws.
LCE (Lancaster Choice Energy)	The Community Choice Aggregator, and Load Serving Entity, providing energy and energy services within Lancaster, CA.
LCOE (Levelized Cost of Electricity)	The cost of energy from an electricity resource that is based on the system's installed price, its total lifetime cost, and its lifetime electricity production. It is calculated by dividing the net present value of the annual system costs by the net present value of the system’s energy production over its expected life.
LSE (Load Serving Entity)	Entities that have been granted authority by state or local law, regulation or franchise to serve their own load directly through wholesale energy purchases.
MCE (Marin Clean Energy)	A Community Choice Aggregator serving Marin and Napa Counties.
MGCC (Microgrid Central Controller)	A device that oversees the operation and control of the microgrid whose function is to properly balance the generating capacity of DERs with the microgrid’s total load.

NEM (Net Energy Metering)	A state-mandated program through which utility customers with behind-the-meter renewable generating facilities smaller than 1 MW can receive bill credit and payment for power not used on-site and delivered to the grid (causing the meter to “run backwards”).
NEMA (Net Energy Metering Aggregation)	A program that allows a single customer with multiple meters on the same property, or on adjacent or contiguous properties, to use renewable generation (for example solar panels) to serve the aggregated load behind all eligible meters and receive the benefits of Net Energy Metering (NEM).
NEM-V (Virtual Net Energy Metering)	A mechanism that encourages community solar by enabling investors or subscribers of a solar facility to benefit from their share of the electricity generated as if that share were generated behind their meter.
PCC (Point of Common Connection)	The point in an electrical system where multiple customers or multiple electrical loads may be connected.
PPA (Power Purchase Agreement)	A contract between an electricity producer and customer, in which the consumer purchases a specified amount of electricity for a specified period of time (usually 10-20 years) at a specified price (usually below short-term market rates). Solar power purchase agreements are frequently used by load serving entities to purchase renewable energy from local sources. There is almost no up-front cost to the LSE, and the producer takes on the construction, maintenance, and risk of the system.
RA (Resource Adequacy)	A program that ensures that adequate physical generating capacity dedicated to serving all load requirements is available to meet peak demand and planning and operating reserves, at or deliverable to locations and at times as may be necessary to ensure local area reliability and system reliability.
SCP (Sonoma Clean Power)	A CCA and not-for-profit public agency, independently run by the cities of Cloverdale, Cotati, Fort Bragg, Petaluma, Point Arena, Rohnert Park, Santa Rosa, Sebastopol, Sonoma, Willits, Windsor, and the counties of Sonoma and Mendocino with the goal to invest in renewable power and local jobs.
Smart grid	Smart grid is the thoughtful integration of intelligent technologies and innovative services that produce a more efficient, sustainable, economic, and secure electrical supply for California communities.
TOU (Time of Use)	Electricity prices that vary depending on the time periods in which the energy is consumed. In a time-of- use rate structure, higher prices are charged during utility peak-load times. Such rates can provide an incentive for consumers to curb power use during peak times.

APPENDIX A: Deliverables Created for the AEC Project

Following is a summary of all the major deliverables created for AEC project purposes. This list, as well as links to each deliverable, will be available at www.znealliance.org.

Residential Microgrids

Finance

- **Legal and Policy Framework for Using Land-Secured Finance to Achieve ZNE:** An analysis of the possible routes and barriers to using land secured financing to fund community scale solar facilities, covering current laws and building codes, and concluding with recommended policy and code updates to streamline this financing process.
- ZNE Community Financial Model deliverables:
  - ***ZNE Community Financial Model Report.*** A report describing the ZNE Community Financial Model, including assumptions, inputs, and interpretation of output.
  - **ZNE Community Financial Model.** An Excel-based financial model that estimates energy consumption, generation and storage needs, project costs, and financing costs for a ZNE community.
  - ***Municipal-Financed ZNE Community Market Characterization, Challenges and Opportunities Report.*** A report covering the assumptions and inputs, outputs, key performance indicators and known issues of the ZNE Community Financial Model.

Technical

Technical Framework and Specification deliverables:

- ***Technical Requirements and Customer Needs Report.*** A discussion of the value, design, and operation of microgrids for residential communities, including how microgrids fit into California's current energy landscape, market actors involved in developing and maintaining a residential microgrid, and identifying critical market facilitation needs and opportunities.
- **Control System Specification.** An in-depth analysis of the microgrid control system, including control strategies, components, communication protocol, cybersecurity, and technical schematics.
- **ZNE Subdivision Technical Design.** A technical design of City of Lancaster's Avenue I residential microgrid, including use case analysis, community load summaries, component sizing, participation in demand response programs, and technical schematics that will be incorporated into architectural and construction documents.
- **Residential Subdivision Permitting and Interconnection Challenges and Opportunities.** An outline of the residential microgrid's interconnection requirements, including the

process for Lancaster Choice Energy (LCE) to own the transmission and distribution assets within the microgrid community, and requirements and opportunities to integrate the community microgrid into Southern California Edison's larger grid.

- **Cost-Benefit Analysis.** An economic analysis for the trade-offs associated with the use case and sizing of the residential microgrid to maximize cost-effective grid and customer benefits in the final technical design.

DER Value Creation

Community DER Valuation Framework

- ***Community DER Business Model Framework Specification Report.*** An introductory report summarizing the approach and methodology to valuing DERs for CCAs and other non-IOU LSEs.
- ***Community DER Valuation Framework Report.*** An in-depth investigation into the valuation methods, value streams, business models and use cases for DER assessment for CCAs and other non-IOU LSEs.
- **Community DER Valuation Framework/Model.** A series of spreadsheet tools that can be used for valuing DERs, including separate modules for community solar, NEM solar and energy storage, EV smart charging and energy storage, and demand response.
- ***Community DER Valuation Framework User Manual.*** A user guide documenting the step-by-step instructions for using the Community DER Valuation Framework Models, supported by case study applications of the models.
- ***Community DER Market Characterization and Implementation Strategy Report.*** A documentation of emerging trends and forecasts for the DER markets in California and beyond, including technology research and business model implications for DERs and strategies for their implementation.

Scalable Public/Private Partnerships

- ***Buyer Perceptions and Business Model Challenges & Opportunities Report.*** A thorough exploration of barriers, both perceived and real, to EV adoption for fleet managers, and how these can be addressed, in Lancaster and broadly.
- ***EV and Stationary Storage Procurement Report.*** An economic analysis of the potential to and feasibility of using second-life EV batteries for stationary storage.
- ***Public/Private Business Model Summary Report.*** A framework that details how to design public/private partnerships to ensure all stakeholder incentives are aligned for program success.

Plan and Permit Large-Scale DER Deployment

- **Site Profile Reports:** Descriptions of potential site profiles for large-scale DER deployment, including ownership, property details, ownership/partners, and potential sizing of DER deployment.
- ***Interconnection Application for Community DER Report.*** A map of the process of how to apply for interconnection for a commercial-scale battery storage project.

- ***Community DER Interconnection Report.*** An outline of a commercial-scale battery storage project's interconnection requirements, including the process for Lancaster Choice Energy to batch multiple storage application into one interconnection application to Southern California Edison.