BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking To Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	Rulemaking 18-07-003

CLEAN COALITION COMMENTS IN RESPONSE TO THE ADMINISTRATIVE LAW JUDGE'S RULING AND STAFF PROPOSAL WITH PROPOSED MODIFICATIONS TO THE RENEWABLE MARKET ADJUSTING TARIFF PROGRAM

/s/ BEN SCHWARTZ
Ben Schwartz
Policy Associate
Clean Coalition
1800 Garden Street
Santa Barbara, CA 93101
Phone: 626-232-7573
ben@clean-coalition.org

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I. INTRODUCTION

Pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") the Clean Coalition submits these reply comments on the Administrative Law Judge's ("ALJ") Ruling and Staff Proposal regarding proposed modifications to ReMAT, issued in the above captioned proceeding on June 26, 2020. The Clean Coalition applauds the Commission's attempt to focus on the Renewable Market Adjusting Tariff ("ReMAT") to comply with state-mandated Renewable Portfolio Standards ("RPS"), which is an acknowledgement that at least 750 MW of energy must be procured. As of November 2017 — one month before ReMAT was suspended for non-compliance with the Public Utility Regulatory Act of 1978 ("PURPA") — the three IOUs had procured just over half of the total 450 MW the Commission determined they are responsible for, "requiring them to procure an additional 238 MW to meet their portion of the statewide procurement target."[1] The nature of ReMAT is a first come, first served tariff; the Clean Coalition strongly believes that the original ReMAT program should be applied temporarily to those facilities that have been waiting in the interconnection queue — paying fees to keep their position for multiple years — with the fewest possible ReMAT modifications.

The *Winding Creek Order* deemed ReMAT as non-compliant with PURPA due to the total MW cap and limiting contracts since there was no option for time-of-delivery contracts in addition to time-of-execution contracts. These are issues that should be considered in the long-term, but it is worth noting that the Commission passed a new Standard Offer Contract ("SOC") program for Qualifying Facilities ("QF") 20 MW and under, which is PURPA compliant. Thus, while minor changes should be made to ReMAT in the interim, it is essential to sustain project

[1] Staff Proposal, Page 5

demand for a future tariff by demonstrating that projects which have waited for almost three years will indeed be procured at the intended market rate and can begin making a return on investment. California now has a primary program to comply with PURPA, meaning that ReMAT no longer needs to be structured to fill that role.

To wholly comply with the *Winding Creek Order*, an effective ReMAT program must calculate a true avoided cost of energy, which is not static, nor will it be entirely similar for locations across California. A single estimated number cannot represent a fair market rate, much less the actual avoided cost. The difference in the value between peak energy and non-peak energy is significant enough to merit different costs on its own, but when combined with the differences in marginal price in various locations across California, it is clear that a single unchanging number, agreed upon by the Commission via resolution <u>once</u> a year, is not sufficient to reflect the changing market. The Staff Proposal attempts to solve the PURPA violations presented in the *Winding Solar Order*, but it does not matter if the Commission offers options for calculating the avoided cost, "at the time of delivery; or… at the time the obligation is incurred," since the proposed costs cannot come anywhere close to representing a true avoided cost of energy without considering a value of resilience and the avoided transmission cost of ReMAT projects.[2] ReMAT projects are interconnected to the distribution grid and thus do not use the transmission system and should not be burdened with transmission costs, which are 100% in the form of volumetric usage fees, known as Transmission Access Charges ("TAC").

The Staff Proposal estimates prices through a collection of RPS contracts from the three IOUs between 2013 and 2019, but the vast majority of projects are over 5 MW and multiple projects are over 100 MW. Out of a total 69 contracts presented in the Staff Proposal, only seven are 5.0 MW or under, which is 10.1%. How is that in any way representative of the demand for the smally types of projects that utilize ReMAT? It is utterly ridiculous to compare the price of such massive projects, which incur massive costs from interconnecting via CAISO, to ReMAT projects, with are all under 3 MW. Moreover, the majority of contracts analyzed are from SCE service territory; there are only seven SDG&E contracts and thirteen PG&E contracts total in the data set. As if the skewed data wasn't enough to challenge the method of calculation for the administratively set prices in the Staff Proposal, there are also only five contracts in the data set after the year 2016 (and none after 2018); prices have most certainly changed since then. With

[2] 18 C.F.R. § 292.304(d)(2)

the Commission focusing this proceeding on a Staff Proposal that bases prices on contracts mostly from more than two years ago, it makes much more sense to apply ReMAT temporarily and then create a successor tariff which is as effective as possible. A time-of-delivery adjustment is not enough to fix a base set of prices that are badly misaligned with reality and can only be amended once a year via a resolution (which does not require as high of an evidentiary standard as an actual Commission decision would). It is abundantly clear that the Staff Proposal is not an appropriate approach and would only cause more problems than it would solve.

There is a far superior method that has already been designed to offer pricing at the time of contract execution and/or the time of product delivery; the Feed-In Tariff ("FIT") that the Clean Coalition designed for the City of San Diego in 2019 that includes market responsive pricing and a dispatchability adder that properly values resilience and compensates for energy storage to ensure the renewables can be delivered when best for the grid, rather than just when the sun is shining or wind is blowing.[3] The Commission needs to begin designing a successor tariff that can enable the first true Community Microgrids throughout California and create a standard for the true value of resilience that is sorely needed in energy policy.

DESCRIPTION OF PARTY

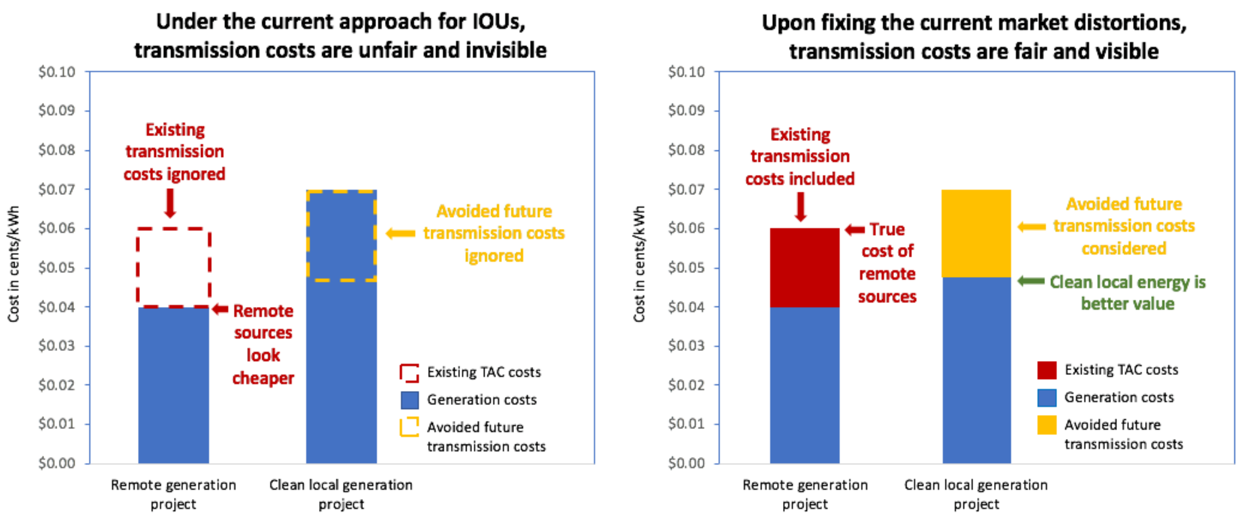
The Clean Coalition is a nonprofit organization whose mission is to accelerate the transition to renewable energy and a modern grid through technical, policy, and project development expertise. The Clean Coalition drives policy innovation to remove barriers to procurement and interconnection of distributed energy resources ("DER") — such as local renewables, demand response, and energy storage — and we establish market mechanisms that realize the full potential of integrating these solutions for optimized economic, environmental, and resilience benefits. The Clean Coalition also collaborates with utilities, municipalities, property owners, and other stakeholders to create near-term deployment opportunities that prove the unparalleled benefits of local renewables and other DER.

II. COMMENTS

The Staff Proposal's pricing incorrectly values the true avoided cost of energy because it does not consider of avoided transmission costs.

[3] San Diego Feed-In Tariff and Solar Siting Survey https://clean-coalition.org/san-diego/

One of the key value propositions of small distributed generation projects is the ability to be deployed more quickly than large RPS projects. This fact is represented in the Avoided Cost Calculator. As part of the 2020 update to the Avoided Cost Calculator, the Commission affirmed that each of the three IOUs must value the DER-avoided cost of transmission investment (just load growth so far), including in the form of Community Microgrids and other Non-Wire Alternatives ("NWAs"). Avoiding the need for new transmission, from load growth alone, is worth an additional 2.5 cents/kWh in the evenings, in addition to the current value of existing transmission costs which average about 2 cents/kWh. As illustrated in this infographic, current distortions in allocating transmission cost steal roughly 4.5 cents/kWh of value from local renewables and other DER:



Existing transmission costs, currently averaging 2¢/kWh, should be added to the cost of remote generation that requires use of the transmission grid to get energy from where it is generated to where it is used. Future transmission investments, currently averaging 2.5¢/kWh in the evenings, can be avoided via dispatchable local generation, and that value should reduce the evaluated cost of local generation. When correctly considering ratepayer impacts of transmission costs, dispatchable local generation provides an average of 4.5¢/kWh of better value to ratepayers than is currently assumed in the majority of instances.

Because current TAC in IOU service territories are calculated at the customer meter, rather than at the transmission-distribution substation, all energy is charged that 2 cents/kWh TAC as if it all used the transmission grid. Importantly, in non-IOU service territories, TAC are metered and assessed properly, at the transmission-distribution substation for non-IOU service territories.

Projects procured as part of the ReMAT program and small, interconnected to the distribution grid, and do not utilize the transmission grid. As such, ReMAT should not incur

TAC, which lowers the true avoided cost of local renewables and other DER.[4] These types of wholesale distributed generation projects are interconnected to the distribution grid and — without exception in the Clean Coalition's experience — a serve local loads without ever traveling over the transmission grid. Section 399.20 (e) of the California Public Utilities Code states, "the commission shall consider and may establish a value for an electric generation facility located on a distribution circuit that generates electricity at a time and in a manner so as to offset the peak demand on the distribution circuit."[5] If the peak pricing value provided in the Staff Proposal is supposed to represent the Commission's attempt to comply with this section of the code then (a), it is an acknowledgement that all projects in the wholesale distributed generation category are interconnected to the distribution grid and (b), there is no reason that ReMAT projects should incur TAC. ReMAT projects, unlike the larger RPS projects they are compared to in the Staff Proposal, will not incur costs for upgrading transmission infrastructure. A true avoided cost of energy should reflect the avoided transmission costs, including TAC and avoided peak usage of the transmission grid. Lastly, (c), the Staff Proposal does not consider the higher efficiency of ReMAT projects because the energy is delivered directly to the customer meter without the transmission losses, which must be factored into the true avoided cost of energy.

The Staff Proposal does not consider a value of resilience, which is one of the key value propositions of local renewables and associated DER.

Local renewables and associated DER provide resilience benefits that can never be provisioned by remote energy generation of any flavor. The successor tariff to ReMAT needs to provide a mechanism for deploying energy storage in combination with local renewables — to ensure that the value-of-resilience ("VOR") is delivered with other grid services. Such a feature would be impossible with the pricing mechanism described in the Staff Proposal, which determines pricing by lumping together past RPS contracts that are mainly interconnected to the transmission grid with a select few projects that are small enough to be interconnected to the

[4] https://www.tdworld.com/distributed-energy-resources/article/21132853/how-two-simple-fixes-can-fairly-compensate-the-true-value-of-ders-in-california

[5] California PUC § 399.20(e)

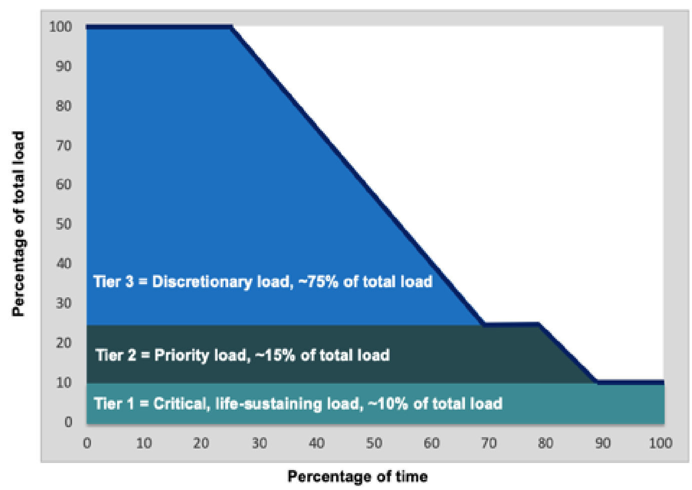
distribution grid. Moreover, it promulgates the lack of a VOR definition, which is the first requirement to creating a market mechanism that procures VOR. It is time to overcome this long-standing regulatory failure. The Commission should seek to set regulation that adheres to the letter of the law, while also not impeding the progress of clean energy innovation and development — and the evolution of the necessary services that the market values, like resilience. Ideally, the Commission should empower progress; valuing resilience is one of those key areas where a few simple actions by the Commission will have a variety of positive impacts. The diagram below explains the Clean Coalition's VOR123 methodology to properly value resilience.

Load tiering and valuing resilience ("VOR123" methodology)

With respect to valuing resilience, there are different VOR levels for each of the three load tiers. The following valuation ranges are typical for most sites:

- **Tier 1**: 100% resilience is worth approximately 3 to 5 times the normal price paid for electricity. In other words, indefinite energy resilience for critical loads is worth 3 to 4 times the normal price paid for electricity. Given that the typical facility has a Tier 1 load that is about 10% of the total load, applying the low side of the Tier 1 VOR multiplier typically yields a 20% adder to the pre-resilience electricity rate.
- **Tier 2**: 80% resilience is worth approximately 1.5 to 3 times the normal price paid for electricity. In other words, energy resilience that is provisioned at least 80% of the time for priority loads is worth 1.5 to 2.5 times the total, so applying the low side of the Tier 2 VOR multiplier yields a 7.5% adder on top of the pre-resilience electricity rate.
- **Tier 3**: Although a standard-size solar microgrid can provide backup power to Tier 3 loads a substantial percentage of the time, Tier 3 loads are by definition discretionary, and therefore, a Tier 3 VOR multiplier is negligible and assumed to be zero.

Taken together, the Tier 1 and Tier 2 premiums for a standard load tiering allocation yields an effective VOR of between 25% and 30%. Hence, **the Clean Coalition uses 25% as the typical premium that a site should be willing to pay for indefinite renewables-driven backup power to critical loads** — along with renewables-driven backup for the rest of the loads for significant percentages of time.



Average anticipated resilience, in terms of percentage of time online:

- Tier 1: 100%
- Tier 2: 80% (at least)
- Tier 3: 25% (at least)

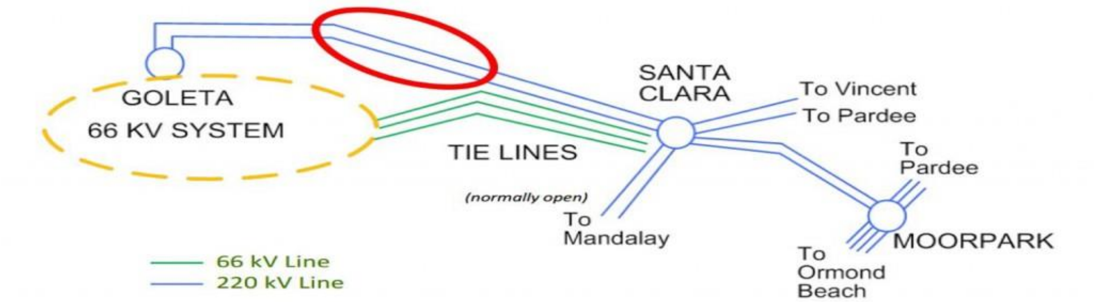
The question that the must be asked is, if individual facilities are willing to pay this much more for clean energy and resilience, what is that value to California ratepayers more broadly — and to the IOUs that are entrusted to serve the majority of California's ratepayers? Considering the number of Public Safety Power Shutoffs ("PSPS") in 2019, the VOR is certainly much greater than $0.00. SCE claimed that it would reduce the number of PSPS by 70% in 2020 compared to the number that took place in 2019. To actually achieve such an ambitious goal, Community Microgrids should be deployed to provide broad sections of the distribution grid with resilience — so there is enough backup power from local renewables and energy storage to sustain the most critical loads indefinitely, including when the transmission grid is shutdown. In load pockets and high fire threat areas, the IOUs continue to deploy diesel generators for community backup solutions, but that is simply a bad approach for lots of reasons. In any case, this ill-conceived diesel approach is a clear indication that there is a substantial VOR that should be factored into successor ReMAT pricing. The Staff Proposal pricing fails to consider the VOR benefit of local renewables, and thus cannot be considered a realistic option.

The Goleta Load Pocket is a perfect example of the need to include resilience in the avoided cost of electricity and a reason why the Commission should be visionary with a successor. ReMAT, rather than reverting to a lowest-common-denominator, business-as-usual approach.

In the Goleta Load Pocket region (GLP) in 2015, SCE implemented contracts to deploy 80 MW of temporary diesel generators for emergency backup power leading up to the strong forecasted El Nino season.

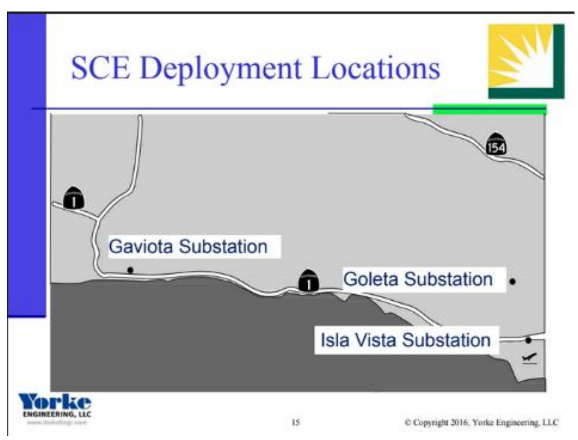
Map of the GLP (the purple line is the single transmission line in the region)

The GLP spans 70 miles of California coastline, from Point Conception to Lake Casitas, encompassing the cities of Goleta, Santa Barbara (including Montecito), and Carpinteria. The region is at the northwest end of the SCE's service territory and relies entirely on one coterminous set of transmission lines routed through 40 miles of rugged mountainous terrain.



Transmission Infrastructure in the GLP

Southern California Edison (SCE) has repeatedly characterized these transmission lines as at risk for catastrophic failure from fire, earthquake, or heavy rains, which could potentially cause a crippling, extended blackout of weeks or even months. In 2015, leading up to the expected wet winter in the El Nino season, SCE contracted 79.5 MW of temporary generation, via 41 diesel generators, that were put at three substation locations.

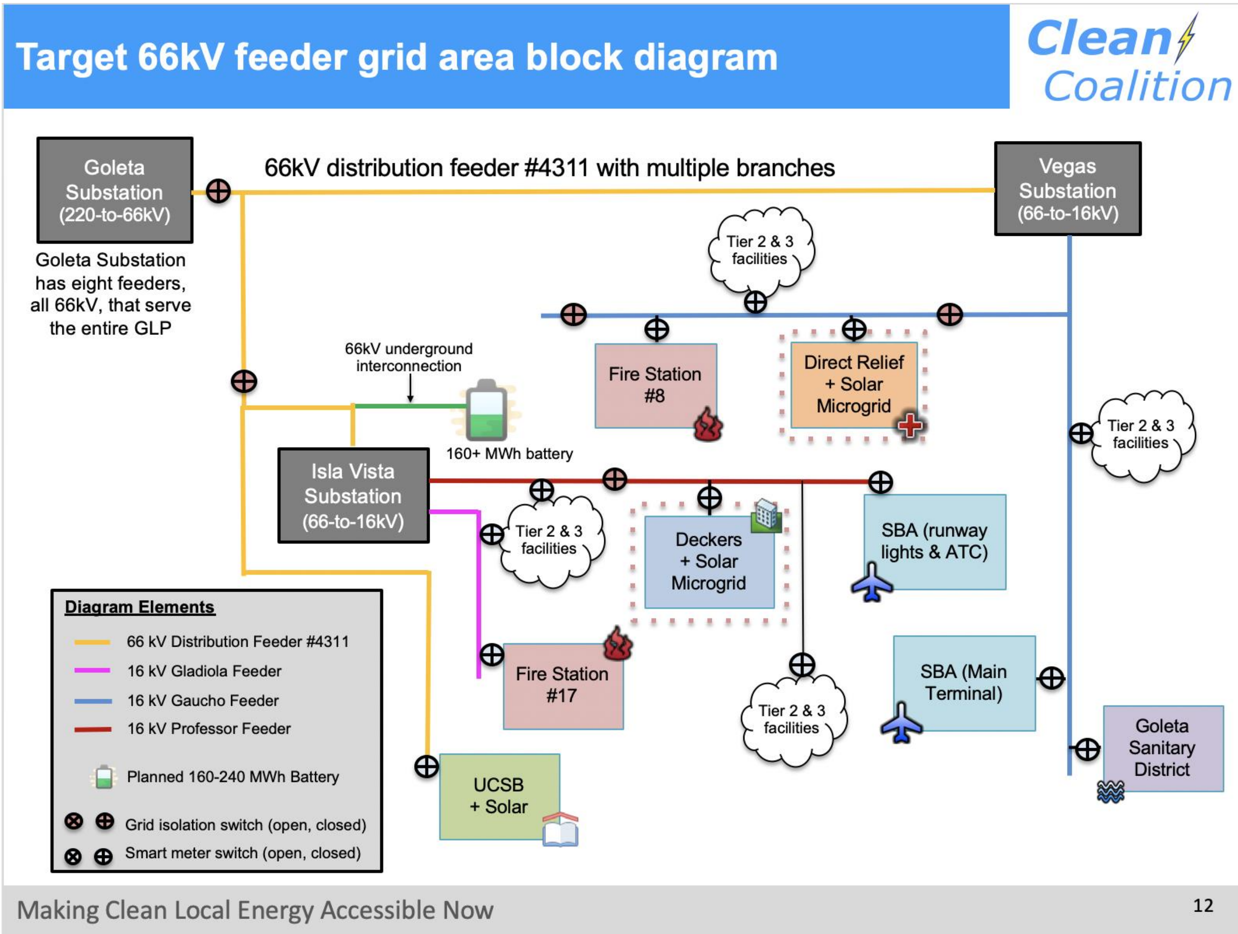


Though the generators were not used, their strategic placement offer a great opportunity to determine what SCE considers to be necessary to make the region resilient. According to Clean Coalition calculations, to achieve indefinite renewables-driven backup power that provides 100% protection to the GLP against a complete transmission outage ("N-2 event"), 200 MW of solar and 400 megawatt-hours (MWh) of energy storage needs to be sited within the GLP. Permanently replacing temporary diesel generators with installed renewable generation via ReMAT could cover 40% of that 200 MW resiliency floor, moving the area that much closer to 100% protection against a transmission outage of any duration. A full transition to renewable projects would add another layer of permanent resilience the generators were never able or designed to achieve – a cost that should be considered in the value conveyed under any successor ReMAT rate.

Just as important is the potential for a new and improved ReMAT to usher in the era of Community Microgrids. To create a successful Community Microgrid, it is necessary to populate the distribution grid with a suitable amount of DER, which is not possible in locations that are both restricted by Net Energy Metering and do not have a suitable FIT. The Goleta Load Pocket is a perfect example of that. For example, Direct Relief is a non-profit in Santa Barbara which is interested in harnessing its property in support of the GLP Community Microgrid but is presently unable to use 75% of the available space. The two photographs below demonstrate this situation; on the left is the space currently being used via NEM and the photo on the right highlights that total potential space that could be utilized through a FIT such as ReMAT.

Net energy metering (NEM) limits Direct Relief to 320 kW of solar even though its rooftop and parking lots can support almost four time that amount of solar.

Through ReMAT, Direct Relief would be allowed to serve the local community and the broader GLP. Earlier this year, the CPUC approved the installation of a 160 MW battery in the GLP by March of 2021; with an effective mechanism like ReMAT to allow penetrations of solar to tie together with the energy storage, the GLP is the perfect opportunity of a scaled community microgrid project. The below block diagram shows the potential of this critical portion of the GLP — and the basis of a robust Community Microgrid that a properly designed successor ReMAT can enable – by attracting the local. renewables and other DER that are drastically needed for GLP resilience.



The Clean Coalition offers the example of a FIT created for the City of San Diego

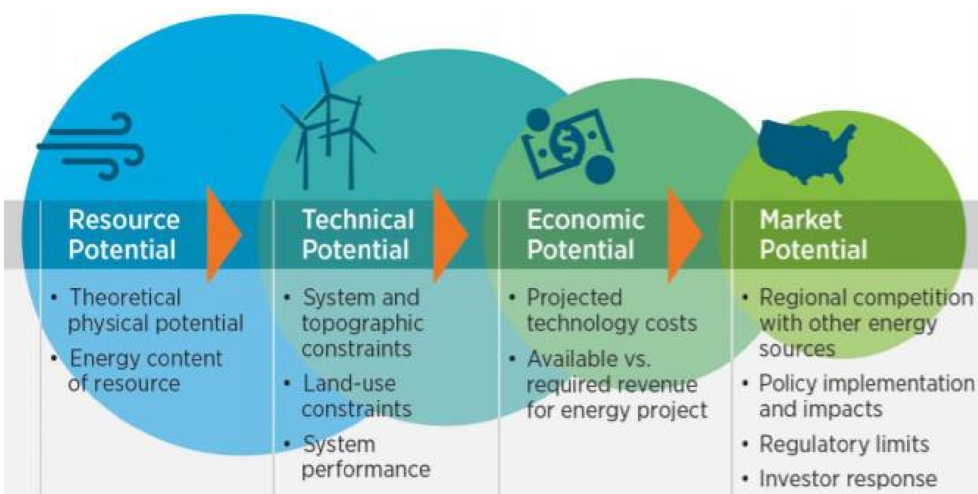
The Clean Coalition designed a FIT for the City of San Diego that includes all RPS-compliant technologies, which makes it a perfect example for what ReMAT should strive to achieve. Delineated as Appendix A below, the FIT advises the use of four adders, including market responsive pricing for the primary FIT rate as well as a dispatchability adder (with a market responsive pricing mechanism), which leads to the procurement of cost-effective clean energy that can deployed when it is most needed on the local grid. The four adders are as follows:

1) a built environment adder to guide FIT projects to be sited on rooftops, parking lots, parking structures, and other built environments;
2) a small project adder to support a greater diversity of FIT projects;
3) a community benefit adder to guide siting of FIT projects in disadvantaged communities and on tax-exempt built environments; and

4) a Dispatchability Adder to support the development of storage projects paired with FIT projects.[6]

The original ReMAT program included a market responsive pricing mechanism, though methods to make it more effective — including a dispatchability adder — should be discussed in the creation of a ReMAT successor. Once an initial price is determined, which in this case would be the accurate value of the avoided cost of energy, market responsive pricing would ensure that the most effective is set after each tranche. However, a system of administrative pricing set once a year, advocated for in the Staff Proposal, does not create an accurate base rate that can be adjusted. As the San Diego FIT explains:

> administratively set fixed prices are optimal only if the price matches actual market prices. If the price is set too low, there is insufficient participation in the program. If the price is set too high, then a "gold rush" may ensue and the buyer will overpay for energy. Administrative determination of appropriate pricing requires significant effort, and even the best effort cannot perfectly account for all market factors.[7]



Market Potential Graphic[8]

The "avoided cost of energy" mentioned in the ALJ ruling compares small MW projects to the average way the IOUs procures energy, which usually occurs via bulk remote generation interconnected to the transmission system. This makes for a tough comparison, as does the fact that ReMAT does not consider the importance of energy storage by forcing all projects into the rigid categories of as-available peaking, as-available non-peaking, and baseload. This is the exact

[6] San Diego FIT, Page 2
[7] Ibid, Page 9
[8] Ibid, Page 14

reason that the Clean Coalition-designed FIT for the City of San Diego includes a dispatchability adder with a market responsive pricing adjustment mechanism. Beyond the importance of allowing the procurement of energy when it is most needed by the grid, the addition of a dispatchability adder allows a program like ReMAT to promote resilience — an essential component in the energy climate in California.

III. CONCLUSION

The Clean Coalition appreciates the opportunity to submit these comments in response to the proposed modification to ReMAT. An effectively designed ReMAT can be applied as easily at the state level as it can on the local level. Municipalities and CCAs look to the state when designing programs which makes it all the more important that the design and pricing mechanisms are properly considered. A Staff Proposal offering starting prices based on skewed data and then a hastily offered time-of-delivery adjustment option — as if that will solve the underlying problems — cannot be the model that the Commission offers the public as a final product. The Clean Coalition urges the Commission to deny the Staff Proposal and consider a more effective FIT using the model the Clean Coalition created for the City of San Diego.

/s/ BEN SCHWARTZ
Ben Schwartz
Policy Associate
Clean Coalition
1800 Garden Street
Santa Barbara, CA 93101
Phone: 626-232-7573
ben@clean-coalition.org

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APPENDIX A

Clean Coalition
Making Clean Local Energy Accessible Now

City of San Diego
Draft Final Feed-in Tariff Design

This Feed -in Tariff Design was prepared by The Clean Coalition
under the direction of the City of San Diego's Sustainability Department.

September 2019

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List of acronyms

Below is a list of acronyms used in this document:

BOS = balance of system
CAISO = California Independent System Operator
CCA = Community Choice Energy
COD = commercial online date
CPUC = California Public Utilities Commission
DSCR = Debt Service Coverage Ratio
FIT = feed-in tariff
GHI = global horizontal irradiance
GWh = gigawatt-hours
ITC = investment tax credit
kW = kilowatt
kWh = kilowatt-hour
LADWP = Los Angeles Department of Water and Power
LSE = load-serving entity
m^2 = meter squared
MRP = Market Responsive Pricing
MW = megawatt
MWh = megawatt-hour
NEM = net energy metering
O&M = operations and maintenance
SDG&E = San Diego Gas and Electric
PPA = power purchase agreement
PV = photovoltaic
RPS = Renewable Portfolio Standard
W = watt
X_{AC} = capacity (in alternating current)[1]
X_{DC} = capacity (in direct current)

[1] All capacity references in this document are in alternating current (AC) unless noted otherwise.

Executive Summary

The document details recommendations for the City of San Diego, and the load-serving entity's (LSE) Feed-in Tariff (FIT) program. The recommendations are based upon relevant market analysis, solar insolation for the City of San Diego, and best practices associated with existing FIT programs worldwide.

This guide is divided into six sections. The first section, titled *Project eligibility*, details the criteria for projects to participate in the LSE's FIT. Any new Renewable Portfolio Standard (RPS)-compliant generating facility, sited within the LSE's territory, and sized up to 3 megawatt (MW) be eligible to participate in the program.

Section two, titled *Program size and timing*, offers recommendations on how to best initiate and expand the FIT program. Capacity for the FIT program will be limited by available budget, which is tied to the expansion of the LSE's customer base and revenues. In summary, the LSE should open a 7.5 MW_{AC}[2] program in spring 2019, with a plan to open an additional 7.5 MW of new program capacity quarterly with 5 MW in the last quarter, reaching 50 MW of allocated capacity by spring 2022. A 50 MW FIT program would supply roughly 1.1% of the LSE's total annual energy sales from local renewable energy sources.

Section three, titled *Pricing*, provides insights and recommendations for initial FIT program pricing and overall pricing design. Initiating the FIT with a 20-year fixed price contract at an initial price of 8¢ per kilowatt-hour (kWh). The program has four pricing adders: 1) a built environment adder to guide FIT projects to be sited on rooftops, parking lots, parking structures, and other built environments; 2) a small project adder to support a greater diversity of FIT projects; 3) a community benefit adder to guide siting of FIT projects in disadvantaged communities and on tax-exempt built environments; and 4) a Dispatchability Adder to support the development of storage projects paired with FIT projects. These pricing recommendations are based upon recent solar pricing data, solar insolation for the City of San Diego, relevant FIT program pricing design, and relevant site lease costs data.

This program also recommends the use of Market Responsive Pricing (MRP), which is a best practice in FIT program design. Pricing is critical to successful procurement under the FIT. The optimum fixed-price contract offer is defined as the price that will attract the desired amount of new local renewable energy capacity within the defined timeframe and at the lowest cost to customers. Prices set too high will ensure rapid development of local renewable energy capacity but will result in *less clean energy produced* for a given budget or cause unnecessary upward impact on electricity rates. Prices set too low will not attract the market to develop the desired amount of local renewable energy capacity. Through Market Responsive Pricing design, the price paid under the FIT will adjust based on market response to ensure the LSE is paying the optimal price for local renewable energy. In addition, MRP has also been applied to the Dispatchability Adder in order to attract the desired amount of storage capacity.

[2] All capacity references in this document are in alternating current (AC) unless noted otherwise.

Section four, titled *Program budget*, details the financial requirements to establish and maintain the FIT program. The budget required will depend on the amount of capacity procured, as well as the price paid for power. Ultimately, the ability to finance expansion of the FIT will depend on the LSE's revenues.

Section five, titled *Policies and procedures*, details how the LSE can manage its FIT program to be efficient and effective. Our recommendations, which are based upon lessons learned from the design of FIT programs nationwide, address how to structure the application process, how to guide projects into and through the program queue, and how to develop effective contracts for wholesale procurement.

Section six, titled *Anticipated challenges*, details potential hurdles the LSE may face when implementing a FIT program.

I. Project eligibility

This section contains recommendations for determining project eligibility for participation in the LSE's FIT program.

a. New resource

The generating resource should be new, meaning that it has not produced or delivered electric energy prior to the date in which the LSE receives its application.

b. Location

The project should be located entirely within the service territory of the LSE, which is comprised of the City of San Diego.

c. Technologies

All technologies that are compliant with California's RPS requirements should be eligible to participate in the FIT. Eligible fuel sources may include, but are not limited to, the following:

- Solar photovoltaic (PV)
- Solar thermal
- Wind
- Digester gas
- Landfill gas
- Geothermal

The development of local renewable energy projects will be determined by physical limitations and resource opportunities in the FIT region, as well as the pricing requirements of the program.

d. Renewable resource quality in the City of San Diego

The City of San Diego has ample solar siting opportunities; more than 490 MW of technical PV siting potential was identified in the Solar Siting Survey of viable sites. A site is defined as a unique address (or group of related addresses) with potential to host at least 1,000 kW (AC) on rooftops, parking lots, parking structures, and logical aggregations thereof.

The City of San Diego boasts a strong solar resource; Figure 1 below shows the solar resource quality — based on global horizontal irradiance (GHI) — across the entire city.

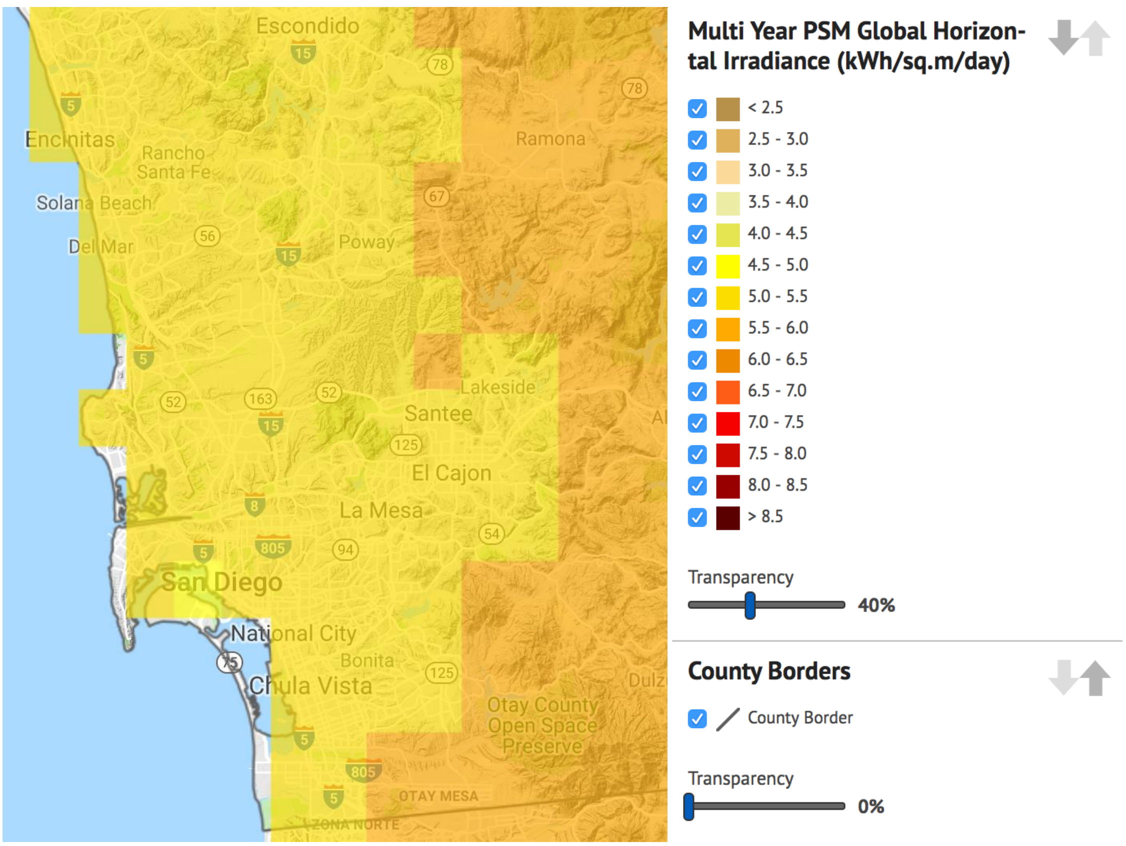

Figure 1: City of San Diego solar resource quality

There is a daily insolation of 4.5-5.0 kWh/m^2/day for the downtown area of the City of San Diego, while the rest of the city has a slightly higher solar resource quality of 5.0-5.5 kWh/m^2/day. This data comes from the National Renewable Energy Laboratory's National Solar Radiation Database.[3]

Solar energy production depends on two primary factors. The first is the solar resource quality, and the second is whether the solar PV system is fixed or follows the sun's rotational path using a tracking system. As shown in Table 1 below, solar installations that utilize a ground-mounted, single-axis tracking system will see greater annual energy production. It should be noted that fixed installations aren't limited to rooftops but can also

[3] "National Solar Radiation Database," National Renewable Energy Laboratory, available at http://rredc.nrel.gov/solar/old_data/nsrdb/1991-2005/tmy3/, last visited October 18, 2018.

be installed as parking canopies or ground mounted Single-axis tracking is used only in larger ground-mounted installations.

Table 1. Solar energy production by locale and system type

Location	Solar resource quality ($kWh/m^2/day$)	System type	Annual energy production (kWh/kW/year)
San Diego	5.00-5.50	Fixed rooftop installation	1900
San Diego	5.00-5.50	Single-axis tracking installation	2371

There was no significant wind potential found within the City of San Diego, as shown in Figure 2 below.

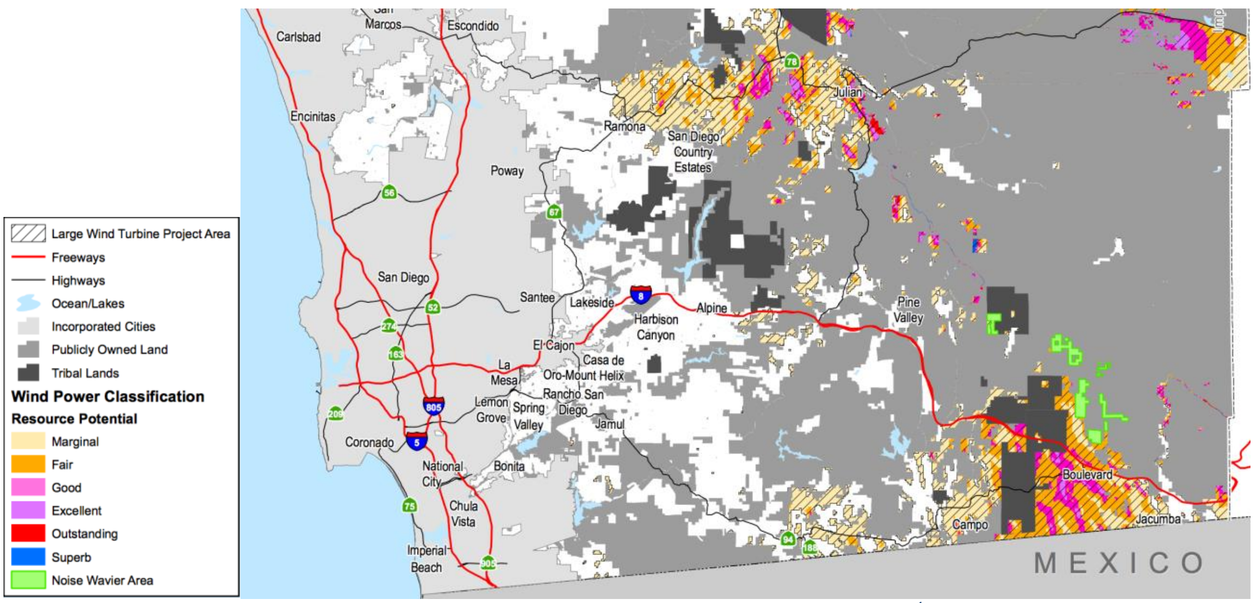

Figure 2: City of San Diego wind resource quality[4]

Based on the assessment of local renewable energy resource potential, solar PV holds the greatest promise for renewable energy generation in the City of San Diego. However, it is unnecessary to prohibit other renewable technologies that are able to produce clean local energy at the established program price. Therefore, a FIT program that is open to all RPS-compliant technologies and allows the market to deliver local renewable electricity generation at the offered price would be more beneficial. However, the LSE may wish to limit eligibility of local sources to zero emission or net emission reduction facilities however.

[4] Planning and Development Services, County of San Diego, 10-007 Wind Energy Ordinance. Wind Resource Map available at https://www.sandiegocounty.gov/pds/advance/BOSMay8POD10-007.html, Last visited October 18, 2018.

e. Project sizing

The maximum allowable project size for the LSE's FIT should be 3 MW. This is slightly larger than similar, existing Community Choice Energy (CCE) FIT programs, including Marin Clean Energy and Sonoma Clean Power, whose FIT programs have a maximum project size of 1 MW. However, the City of San Diego offers plenty of large project siting opportunities, and a larger project cap of 3 MW will enable the LSE to secure lower pricing for local renewable energy through increased economies of scale.

It is worth noting that current California Independent System Operator (CAISO) metering and scheduling requirements impact the cost effectiveness of larger projects once they reach the 1 MW threshold.[4] Any project over 1 MW is required to schedule through energy deliveries through CAISO, which adds capital and operational costs. Therefore, a 3 MW project cap provides enough room for larger projects to handle these additional requirements.

While a smaller maximum project size would ensure that a greater number of projects come online through the FIT given a fixed program capacity, it would also require higher pricing to make projects economically viable. If the LSE wants to ensure a greater number or diversity of FIT projects, then they should offer a small project adder, as Sonoma Clean Power does in its ProFIT program. More details about adders and required pricing based on project size are discussed in detail in *Section III. Pricing*.

II. Program size and timing

This section contains recommendations for the initial size of the LSE's FIT program, as well as an expansion plan that aligns with the projected growth of a possible CCA and makes strong use of the federal investment tax credit (ITC).

f. Initial program size

It is recommended that the LSE launch a FIT program of 7.5 MW, which will meet roughly 0.17% of the City of San Diego's total annual load through this first capacity allocation.

As a frame of reference, it is forecasted that a CCA in San Diego will serve an annual load of 5,600 GWh from 2020 through at least 2034. This load data comes from Willdan Financial Services and EnerNex's feasibility study for a CCA in the City of San Diego on July 2017, which is shown below in Figure 3.

[4] Pacific Gas & Electric, Rule 21 Tariff, Advice Letter # 4565-E, Filed January 20, 2015, Decision No. 14-12-035, pg. 183, available at http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf, last visited October 18, 2018.

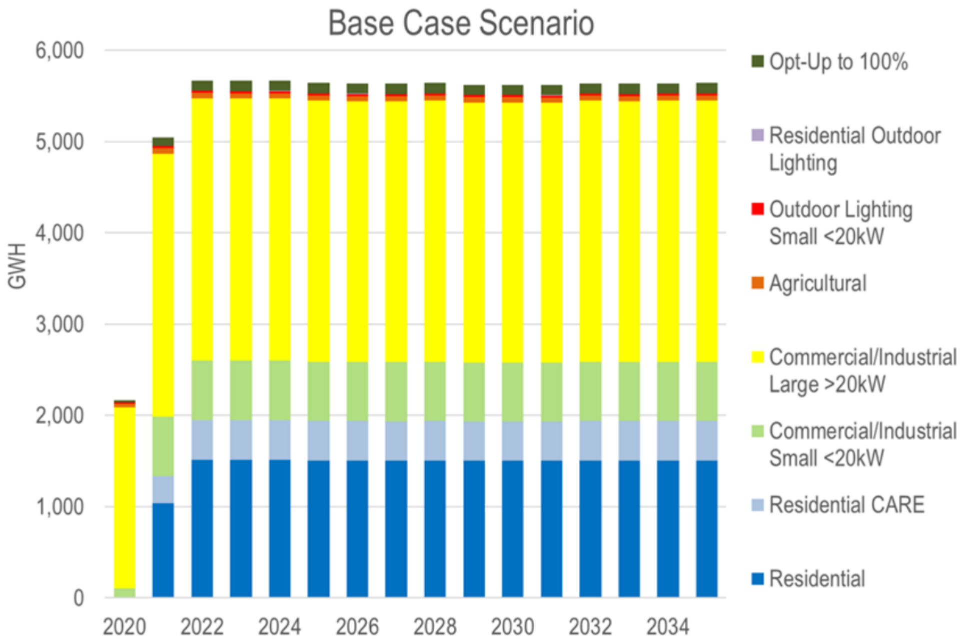

Figure 3: Annual load forecast for the City of San Diego[6]

San Diego Gas and Electric (SDG&E) served an annual load of 8,500 GWh from 2010 to 2016. This load data comes from the City of San Diego's Climate Action Plan 2017 Annual Report Index, which is shown below in Figure 4.

Baseline Year and 2016 Update

The 2010, 2015 and 2016 grid supplied electricity use is provided in Table 4.

Table 4 Electricity Use (grid-supply only) in City of San Diego

	2010	2015 (reported in 2016 Annual Report)	2015 Revised*	2016	2010 - 2016 % Change	2015 Updated - 2016 % Change
Electricity Use (MWh)	8,572,155	8,450,904	8,533,909	8,290,454	-3%	-3%
Emissions from Electricity (MT CO_2e)	3,138,613	2,620,493	2,598,196	2,326,138	-26%	-10%

* Revised values reflect updated information from sources.
MWh = megawatt hour, MT CO_2e = metric tons of carbon dioxide equivalent
The MWhs do not include transmission and distribution losses, or self-serve electricity generation. 2015 and 2016 electricity use excludes military, San Diego Unified Port District, and San Diego International Airport use.

Sources:
SDG&E 2017, Energy Policy Initiatives Center 2017

Figure 4: Annual load for San Diego Gas and Electric[7]

[6] City of San Diego Feasibility Study for a Community Choice Aggregate, July 2017. Available at: https://www.sandiego.gov/sites/default/files/san_diego_cca_feasibility_study_final_draft_main_report_7-11-17.pdf, last visited on October 18, 2018

[7] City of San Diego's Climate Action Plan 2017 Annual Report Index. Available at: https://www.sandiego.gov/sites/default/files/appendix_for_2017_annual_report.pdf. Last visited on October 18, 2018.

An annual load of 8,500 GWh translates to 8,500,000 MWh. 0.17% of this annual load is roughly 14,250 MWh, or 14,250,000 kWh per year. Using a fixed-tilt solar PV system in the City of San Diego as the standard FIT project, each kW of FIT capacity will produce roughly 1,900 kWh/kW/year. This means that a FIT program with a capacity of 7.5 MW will serve 0.17% and 5 MW will serve 0.11% of the LSE's annual load, as illustrated in Table 2 below.

Table 2: Initial LSE Energy FIT program sizing

Initial FIT capacity	Annual energy production from each kW of FIT capacity	Annual energy deliveries through FIT	Annual LSE energy sales	Percent of total LSE retail sales
7.5 MW	1,900 kWh	14,250,000 kWh	8,500,000 MWh	0.17%
5 MW	1,900 kWh	9,500,000 kWh	8,500,000 MWh	0.11%

g. Program expansion and timing

It is recommended that the LSE plan to increase its total FIT program procurement to 50 MW, equal to 1.1% of its total annual load, as shown in Table 3 below.

Table 3: A 50 MW FIT program for the LSE

FIT capacity	Annual energy production from each kW of FIT capacity	Annual energy deliveries through FIT	Annual LSE energy sales	Percent of total LSE retail sales
50 MW	1,900 kWh	95,000,000 kWh	8,500,000 MWh	1.1%

We recommend that the LSE allocate 30 MW of program capacity each year, released in quarterly increments of 7.5 MW, with 5 MW in the last quarter of the second year. Table 4 below offers a program expansion plan that scales the FIT to 50 MW of online capacity by spring 2022, which will provide 1.1% of the LSE's total annual load by its second year of operation. It is worth noting that through offering capacity in predictable, quarterly allocations, the LSE will drive a sustainable and increasingly efficient renewable energy market in the City of San Diego, as well as learning from market response to reduce FIT pricing over time. Market Responsive Pricing design is discussed in detail in *Section III. Pricing*.

Table 4: LSE FIT program expansion and timing

Allocation date	Capacity allocation	Total FIT program size	Estimated commercial online date (COD)[5]	Approximate annual energy deliveries through FIT[6]	FIT as a percentage of total LSE estimated retail sales[7]
Spring 2019	7.5 MW	7.5 MW	Fall 2020	14,250,000 kWh	0.17%
Summer 2019	7.5 MW	15 MW	Winter 2020	28,500,000 kWh	0.34%
Fall 2019	7.5 MW	22.5 MW	Spring 2021	42,750,000 kWh	0.50%
Winter 2019	7.5 MW	30 MW	Summer 2021	57,000,000 kWh	0.67%
Spring 2020	7.5 MW	37.5 MW	Fall 2021	71,250,000 kWh	0.84%
Summer 2020	7.5 MW	45 MW	Winter 2021	85,500,000 kWh	1.0%
Fall 2020	5 MW	50 MW	Spring 2022	95,000,000 kWh	1.1%

h. Timing of contracted capacity

Importantly, there will be a time lag between when the LSE offers FIT program capacity and when projects come online and begin delivering energy to the LSE. We would expect, and recommend requiring, a commercial online date (COD) 12-18 months after the power purchase agreement (PPA) is signed with the LSE. For reference, the Los Angeles Department of Water and Power (LADWP) now requires 12 months to COD, with a possible 6-month extension, in its FIT program. However, it can take a project 6 months or longer to complete the application review process and have a signed PPA after the application is submitted. Applications will not start to come in until after the capacity is released to the market. Therefore, we assume a total lag time of 18 months — 6 months for the application process and PPA execution, and then 12 months to bring the project online.

i. Capacity management

If any capacity remains unclaimed within 30 days of the upcoming allocation, then that excess capacity should be rolled into the next allocation. For example, if a 7.5 MW allocation in spring 2019 receives only 4 MW worth of applications, then the summer 2019 capacity allocation should total 11 MW — the originally planned 7.5 MW plus the 3.5 MW of unclaimed capacity from spring 2019. This will ensure that the program remains on track to deliver the desired capacity in line with the program timeline. Ultimately, budgetary constraints may cap the release of new FIT program capacity. If a higher price must be paid to procure local renewable energy, then the amount of capacity procured may decrease. As the LSE makes this financial determination, it is key to remember too that it will begin paying for power not when FIT capacity is released, but when the projects receive the permission to operate (PTO) — around 18 months later.

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[5] Assuming a total lag time of 18 months from capacity release to FIT projects delivering energy to the LSE — 6 months for the application process and PPA execution, and then 12 months to bring the project online.

[6] This energy will be delivered to the LSE based on the commercial online date of FIT projects — not the capacity allocation date.

[7] Using the commercial online date of FIT projects — not the capacity allocation date.

Last, through a transparent and continual offering of new program capacity, as shown above in Table 4, the LSE can effectively utilize Market Responsive Pricing in its FIT. A Market Response Pricing approach will ensure that the LSE is offering to pay neither more nor less than is necessary to procure local renewable energy. More details on Market Responsive Pricing are provided in the following section on pricing.

III. Pricing

Given that solar PV is expected to be the primary technology responding to the FIT, this pricing analysis evaluates the market pricing required to spur development of wholesale local solar PV installations in the LSE's territory.

Pricing is critical to successful procurement under the FIT. The optimal fixed price is defined as the price that will attract the desired amount of new local renewable energy capacity within the defined timeframe and at the lowest cost to customers. Prices set too high will ensure rapid development of local renewable energy capacity but will result in *less clean energy produced* for a given budget or cause unnecessary upward impact on electricity rates. Prices set too low will not attract the market to develop the desired amount of local renewable energy capacity. It is worth noting that a FIT contract price high enough to trigger a strong market response can drive down renewable energy prices more rapidly over time. This is because as more system installers participate in the local market, increased experience, competition, and economies of scale will support lower FIT prices after the program's initial targets have been reached. However, price declines will be offset to the degree that prime solar siting opportunities are limited in the FIT area, as the best sites will likely be developed early on.

In developing pricing recommendations, the energy resource potential for the City of San Diego is first modeled against standard system performance to establish the technical potential of installations in the city. Full development and operational costs are then modeled for system owners — based on survey data and cost trends to determine the revenue required for the modeled project to be financially viable. Market potential is estimated based on observed market penetration distribution in regional markets in comparison to cost factors and relative siting potential in the City of San Diego, as illustrated in Figure 5 below.

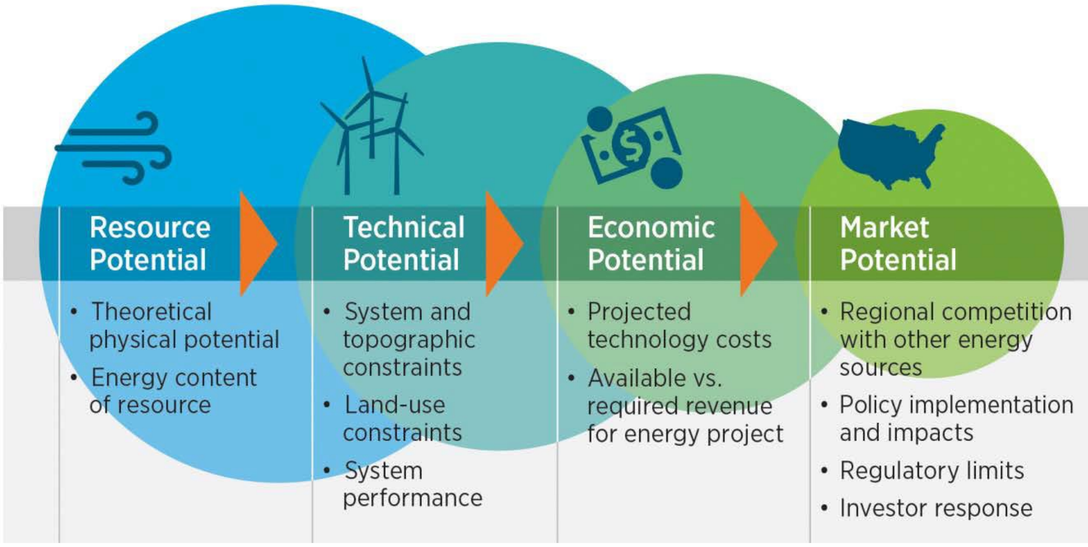

Figure 5: Market potential

j. Initial 20-year fixed pricing

Based on our analysis, it is recommended that the LSE utilize a fixed, non-escalating FIT PPA price initially set at 8¢/kWh for a term of 20 years — recognizing that this will primarily be viable pricing to support larger, ground-mounted projects. Pricing in this range may also support development of solar installations on buildings where property owners are the owner of the FIT system, which would eliminate the site lease cost component.

As Tables 5-7 below illustrate, it is expected that a price of 8¢/kWh is a conservative starting point to incent market development of larger solar PV projects around 3 MW in the LSE's service territory. Smaller projects will require a higher price, as these are assumed to be fixed installations in built environments, producing roughly 20% less energy per watt of capacity. Solar PV projects sized around 500 kW will require an assumed PPA rate of 12.7¢/kWh, while projects around 100 kW will require an even higher assumed PPA rate of 13.9¢/kWh.

Projects sited outside of downtown San Diego are likely to be more cost-effective, as the areas outside of downtown have a slightly higher solar resource, larger PV siting opportunities, and a lower cost of land compared to the rest of the City of San Diego.

Table 5: Required FIT pricing by solar PV project size for the City of San Diego[11]

Type of system	Size of solar PV system (W_{AC})	Installed cost ($/$W_{DC}$)	20-year fixed PPA price (¢/kWh) No sales tax
Built environment	100 kW roof	$2.19	13.9¢
Built environment	350 kW roof	$2.02	12.9¢
Built environment	500 kW roof	$1.96	12.7¢
Built environment	1 MW roof	$1.81	12.0¢
Ground-mount	1 MW tracking	$1.76	9.6¢
Ground-mount	3 MW tracking	$1.70	9.3¢

Pricing at 8¢/kWh is lower than the projected PPA rates shown in Table 5 above. However, this conservative initial FIT pricing is designed to protect the LSE from overpaying for its first 7.5 MW tranche. Given that the LSE won't begin purchasing energy from this first tranche until mid-2020, starting the FIT PPA price at 8¢/kWh accounts for continued reductions in renewable energy costs over the next two years — as well cost reductions expected from the recent passage of Assembly Bill 398, which includes a sales tax exemption for electricity generating facilities (defined as the generation or production, or storage and distribution, of electric power from sources other than a conventional or nuclear power source). The sales tax exemption is anticipated to reduce PPA market rates by roughly 7.75%. The LSE will only set the initial price, and the future PPA price offered through the FIT will be guided by market response, which is discussed in more detail below.

Taking the 3 MW ground-mount project as the standard for the LSE's FIT, since developers will likely make use of these cost-effective project sites first, Table 6 illustrates how costs are expected to change with respect to the year of installation and the role of site lease rates in determining a financially viable FIT price.

[11] The assumptions for this pricing are:
- Pricing is based on site lease cost at 20% of revenue ($40,000/MW/year).
- Observed site lease rates for rooftops have been higher than this 20% revenue-share, adding about 1¢/kWh to the PPA rate. However, the modeled PPA rate is achievable with the LSE's education and outreach to commercial building owners, in conjunction with pro forma Model Lease Agreements.
- Prevailing union wage adds 0.25-0.5¢ to these figures.

Table 6: 3 MW tracking PV system costs and solar prices for a FIT in San Diego

Solar PV system details			Necessary 20-year PPA pricing (¢/kWh)			
Commercial online date (year)	Applicable investment tax credit (ITC) rate	Installed PV system cost at 8% decline annually ($/$W_{DC}$)	With no site lease costs	With site lease cost at 10% of FIT project revenue (~$20/kW/yr)[8]	With site lease cost at 20% of FIT project revenue (~$40/kW/yr)[9]	With site lease costs at $50/kW
2018	30%	$1.70	7.5¢	8.4¢	9.3¢	9.9¢
2019	30%	$1.56	7.0¢	7.9¢	8.8¢	9.4¢
2020	26%	$1.44	6.8¢	7.7¢	8.7¢	9.2¢
2021	22%	$1.32	6.7¢	7.6¢	8.5¢	9.1¢
2022	10%	$1.21	7.0¢	7.9¢	8.8¢	9.4¢

Some site owners may elect to own the FIT system, thereby eliminating site lease costs altogether. For the vast majority of projects, however, third-party ownership of the FIT system is expected and a site lease will be required. It is recommended that the LSE shall promote a de facto standard site lease financial arrangement that is based solely on revenue-share between the third-party FIT owner and the site owner, with 10% to 20% of the revenue being provided to the site owner. Generally, the revenue-share will be lower for ground-mount leases than those on rooftops. The provisioning of standardized, pro forma site lease terms, based on a 10-20% FIT project revenue-share, will save time and cost in the project development process, and expected to be well received by the market. If the LSE were able to facilitate standard site lease arrangements at 10% revenue-share, then it would be able to secure local renewable energy at lower cost, as shown in Table 6.

Also shown in Table 7 is the impact of the federal ITC, which provides a significant incentive for the installation of renewable energy. The ITC begins to decline starting in 2020 and declines markedly in 2022. More details on the ITC are discussed further below.

We based solar PV systems details for Table 6 on historical[10] and projected installed cost trends[11] and component prices,[12] reflecting average costs for similar PV installations in California. This base cost is adjusted to reflect pricing trends for subsequent years, calibrated to comparable metropolitan rooftop PV developments and site lease rates, and adjusted for differences in solar irradiance and sales tax in the City of San Diego.

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[8] Site lease cost based on 10% of PPA gross revenue represents $20/kW/year averaged over the 20-year contract term.

[9] Site lease cost based on 20% of PPA gross revenue represents $40/kW/year averaged over the 20-year contract term.

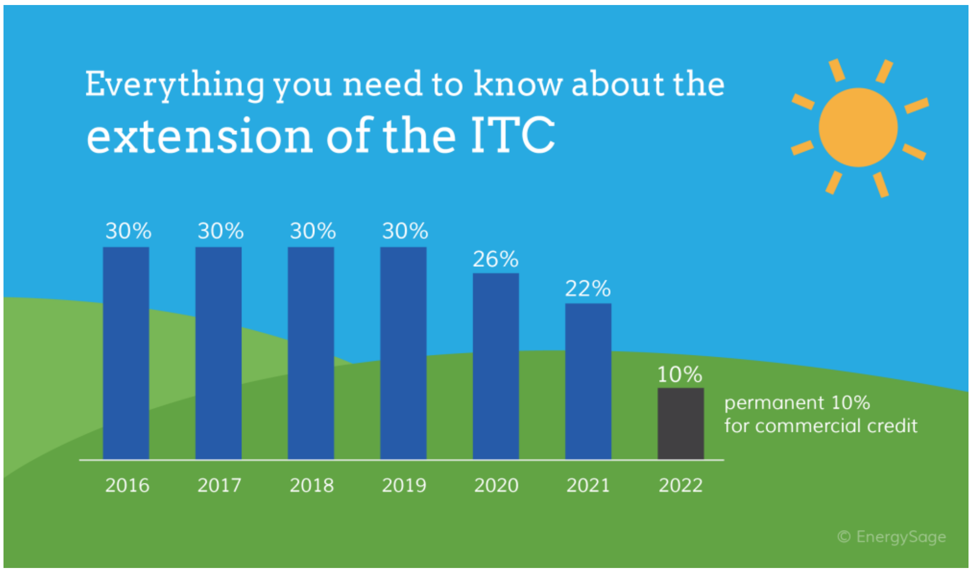
[10] Tracking the Sun Report VII: An Historical Summary of the Installed Price of Photovoltaic in the United States from 1998 to 2013 (September 2017).

[11] Deconstructing Solar Photovoltaic Pricing: The Role of Market Structure, Technology, and Policy (December 2014).

[12] "U.S. Solar Market Insight, Q3 2018," GTM Research and the Solar Energy Industries Association www.greentechmedia.com/research/ussmi, last visited October 18, 2018.

Projected installed cost and component price trends have exhibited annual reductions of approximately 12% in recent years, but there is a strong indication of slower cost decreases through the remainder of the decade. Therefore, the lower value of 8% annual cost decline is reflected in the modeled cost and PPA pricing projection results.

As the PV market further matures, price declines will continue to flatten — resulting in lower decreases in installed costs. This will be further compounded by the fact the ITC will also decrease in the coming years, as shown below.



Source: Energy Sage, April 2016

Figure 6: Extension of the ITC

Therefore, it is not expected that cost reductions in the installed cost of solar PV systems to outpace the planned step-down of the ITC. Given budgetary constraints, it is beneficial for the LSE to bring as much capacity online as possible, before the ITC benefit erodes significantly at year-end 2021. Our recommended FIT program timing will bring all 50 MW of local renewable generation online by Spring 2022 — ensuring that the LSE strongly leverages the financial benefits of the ITC.

k. Market Responsive Pricing structure

The success of an energy procurement program often hinges upon determining the appropriate fixed price paid for energy, which is a major challenge in designing fixed-price, long-term contracts. Historically, the most widely used mechanisms to set a price for energy have been auctions or administrative price setting. However, both mechanisms have been criticized on several fronts.

The high cost for bid preparation and qualification for parties seeking to sell energy, combined with low certainty of success, discourages participation in auctions, while the development of a request for offers and management of the responses is a substantial burden for the purchasing agency. These factors create disproportionately high transaction costs when seeking to attract development of commercial-scale projects. Additionally, the auction approach does not send the market clear and consistent pricing signals that assist developers in determining whether a potential project is financially viable and worth pursuing.

Administratively set fixed prices are optimal only if the price matches actual market prices. If the price is set too low, there is insufficient participation in the program. If the price is set too high, then a "gold rush" may ensue and the buyer will overpay for energy. Administrative determination of appropriate pricing requires significant effort, and even the best effort cannot perfectly account for all market factors.

Market Responsive Pricing (MRP) is an effective and easy-to-implement mechanism that allows the price offered to automatically adjust as the market responds to the program. The essential feature of MRP is to adjust the initial FIT prices offered over time based on the market uptake. With high interest in a FIT, the offered price adjusts downward for future PPAs. With low market interest in a FIT, the offered price adjusts upward for future PPAs. MRP has emerged as a best practice for accurate price discovery, through ongoing polling of the market, over the duration of an energy procurement program.[13] California's Renewable Energy Market Adjusting Tariff (ReMAT) program utilized a similar approach of adjusting the offered price based on market response and has successfully driven competitive pricing for solar PV projects. When purchasing electricity from local renewable generators under a FIT, the LSE should utilize the MRP approach to adjust the price for successive long-term PPA offers.

There are several advantages of MRP over competing pricing mechanisms and methods. By adjusting the contract price offered to developers as the market responds, the LSE can efficiently meet its procurement target without administrative recalculation to estimate the correct price. Pricing with MRP is also fully transparent, resulting in market efficiency and a drive towards the lowest viable prices, while also limiting risky speculation through being forced to place bids at prices that are unreasonably low, as happens with auction programs. Competition between sellers for the available contracts maintains the lowest viable pricing while reducing project failure risk when compared to an auction mechanism, as generators are not trying to win a bid, and are far less likely to contract at a price that is too low for the project to be built. Finally, MRP offers visibility and control over program costs. Procurement planning limits the amount of energy/capacity contracted at the offered price, so policymakers are able to control the rate of uptake, the maximum price paid for energy, and total expenditures for purchased energy.

To implement MRP, program designers must first determine tranches for assessing market response, the magnitude of price adjustments (up and down), and the length of the waiting periods to gauge market response before the price is adjusted. For example, a FIT using MRP will allow the first 7.5 MW of capacity to contract at a starting fixed price. If the first 7.5 MW tranche fills quickly with projects, then the price paid for the following 7.5 MW tranche is reduced by a predetermined adjustment. If, on the other hand, the first 7.5 MW

[13] "Market Responsive Pricing: Policy Mechanism Brief," Clean Coalition, May 2013, available at www.clean-coalition.org/site/wp-content/uploads/2013/07/Market-Responsive-Pricing-Brief-14_ssw-7-May-2013.pdf, last visited October 18, 2018.

of available capacity is not procured within the planned time frame, then the fixed price adjusts upward by a predetermined increment after a set period of time for the subsequent tranche.

The MRP mechanism continues to apply through the lifetime of the FIT, which means that only the initial fixed price is determined in another manner. The use of MRP limits the risk associated with a starting price that might not be optimal, and deliberations over the starting price can be minimized — further reducing administrative burden.

The LSE should be aware that a small program will have proportionately fewer participants, which means fewer data points and limited opportunity for market response. A smaller program also needs time to garner market interest and establish a record of successful contracting and development.

With that in mind, we recommend that the LSE institute an MRP mechanism for its FIT. Pricing adjustments should be made quarterly when new FIT program capacity is allocated. Adjustments of ±0.25¢ are large enough to ensure program pricing is market responsive, while not so large that wild swings in pricing will create an unstable and ineffective program. However, this MRP design includes a price decrease of 0.5¢ if the LSE receives valid applications totaling more than 11.25 MW for any given tranche, which is 150% of the desired 7.5 MW quarterly capacity. This will minimize risk for the LSE by ensuring a larger price drop if the market shows very strong ability to deliver local renewable energy capacity at a set price.

The following guidelines detail our recommended MRP mechanism for the LSE's FIT program:

Downward price adjustment

- If valid applications exceeding 11.25 MW (150% of 7.5 MW, the desired quarterly capacity) have been reserved as of 30 days prior to the next scheduled quarterly procurement, then there is a downward price adjustment of 0.5¢.
- If valid applications totaling between 7.5 MW and 11.25 MW (100-150% of desired quarterly capacity) have been reserved as of 30 days prior to the next scheduled quarterly procurement, then there is a downward price adjustment of 0.25¢.

No price adjustment

- If valid applications totaling between 4.5 MW and 7.5 MW (between 60% and 100% of desired quarterly capacity) have been reserved as of 30 days prior to the next scheduled quarterly procurement, no price adjustment is made.

Upward price adjustment

- If valid applications totaling less than 4.5 MW (less than 60% of desired quarterly capacity) have been reserved as of 30 days prior to the next scheduled quarterly procurement, then there is an upward price adjustment of 0.25¢.

Note that quarterly pricing adjustments allow adequate time for potential providers to respond. And our recommended pricing adjustments are proportional to the level of market response, while providing increments sufficient to change market response in the next allocation.

The LSE should not drop the offered FIT price, via the MRP mechanism, if there is any rollover capacity remaining from previous unfulfilled tranches. This approach will help ensure that the program remains on track to bring the full 50 MW of capacity online by Spring 2022, which will make strong use of the ITC before it declines to 10% in 2022.

The LSE should create a universal maximum price, which is the maximum price the LSE will pay for energy through its FIT program. A clearly defined universal maximum price will send a signal to the market about the LSE's limit, and it will enable the LSE to establish an upper limit for its FIT program budget. It is recommended that the LSE establish 9.5¢/kWh as its universal maximum FIT price.

Figure 7 illustrates the potential MRP adjustments over the few first allocations of the LSE's FIT, with the price adjustments based on market response.

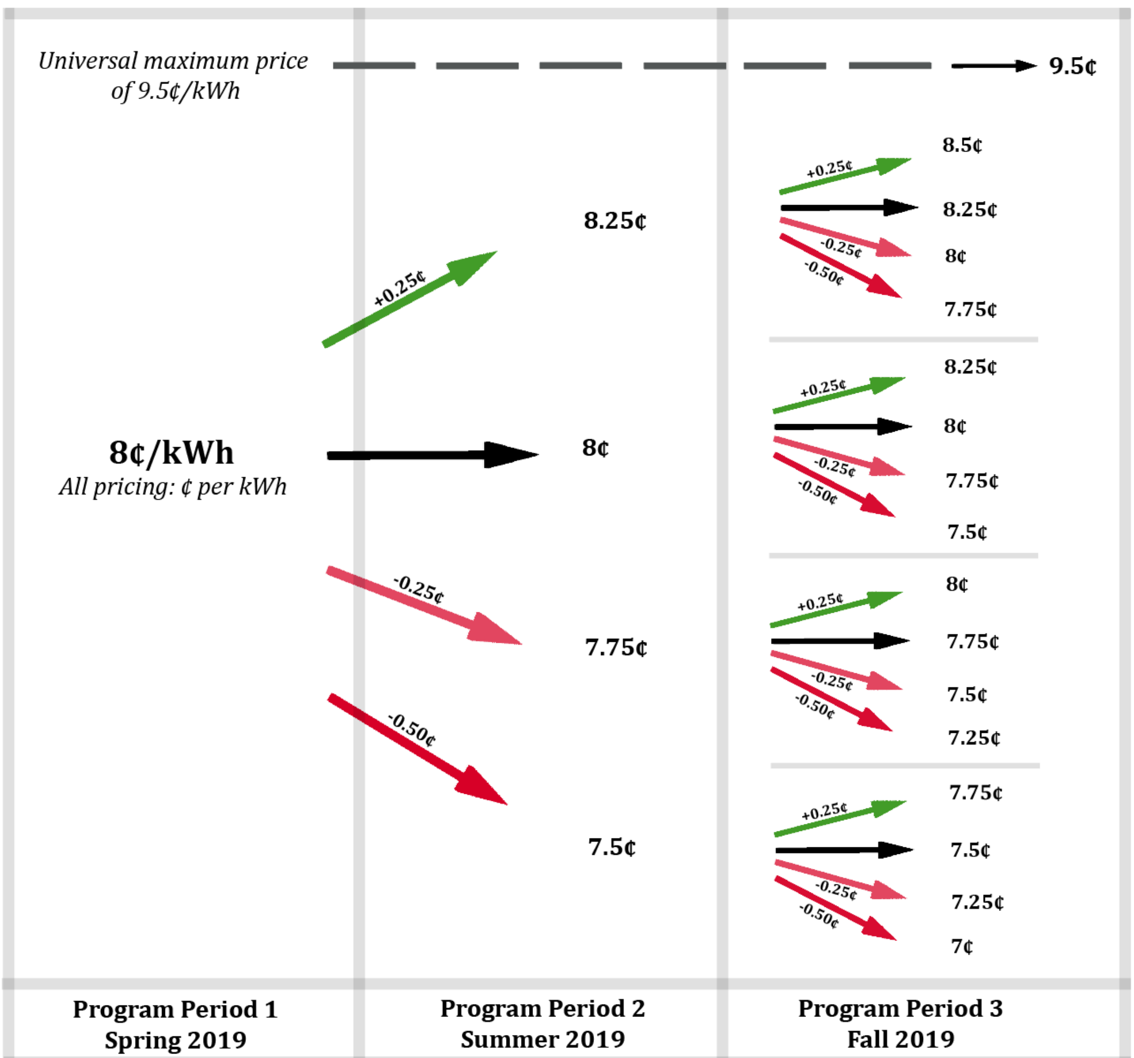


Figure 7: Market Responsive Pricing (MRP) base line for the LSE

l. Pricing adders

It is recommended that initiating the FIT with a fixed, non-escalating PPA price set at 8¢/kWh for a term of 20 years. We also recommend that the LSE offer four pricing adders on top of its FIT rate. The concept of pricing adders is simple. The LSE identifies what characteristics it would like to see in its FIT projects and then creates adders to its FIT price to incentivize these project characteristics. It is recommended that the LSE implement four pricing adders: a built environment adder, a small project adder, a community benefit adder, and a Dispatchability Adder.

i. Built environment adder

Developing local renewable energy projects within the built environment helps preserve pristine spaces and minimizes the environmental impacts of these projects. To drive the siting of FIT projects to within the built environment — which includes rooftops and parking lots — the LSE should offer a 20% built environment adder for projects sited in these locations. The 20% built environment adder will be calculated based on the baseline 20-year FIT pricing. For example, if the LSE is offering 8¢/kWh, then a 1 MW FIT project sited on a large, commercial rooftop would receive 9.6¢/kWh for the full 20-year contract, as illustrated below in Table 7

Table 7: Example pricing for a 1 MWAC rooftop solar project

FIT pricing	Built environment adder (20%)	Final pricing for the FIT project
8¢/kWh	1.6¢/kWh	9.6¢/kWh

ii. Small project adder

To encourage a greater number and diversity of projects to come online through the FIT, that the LSE offer a small project adder.

Any FIT project sized under 350 kW_{AC} should receive a 10% adder on the baseline FIT pricing. Any FIT project sized under 100 kW_{AC} should receive a 20% adder on the baseline FIT pricing. The estimate for a pricing adder that would stimulate some development of smaller projects within the FIT program. The LSE should regularly assess the effectiveness of the small project adder and adjust the adder percentage as necessary, either up or down, depending on the market's ability to develop smaller projects through the FIT program. Table 8 below illustrates initial small project adder.

Table 8: Small project adder

FIT project size	Small project adder (% based off current FIT price)
Less than or equal to 100 kW_{AC}	20%
Greater than 100 kW_{AC} and less than or equal to 350 kW_{AC}	10%
Greater than 350 kW_{AC}	0%

For example, a 350 kW_{AC} FIT project sited on a large commercial rooftop should receive the 20% built environment adder and a 10% small project adder, as illustrated in Table 9 below.

Table 9: Example pricing for a 350 kWAC rooftop solar project

FIT pricing	Built environment adder (20%)	Small project adder for projects between 100 kW and 350 kW (10%)	Final pricing for the FIT project
8¢/kWh	1.6¢/kWh	0.8¢/kWh	10.4¢/kWh

A 100 kW_{AC} FIT project sited on a large commercial rooftop should receive the 20% built environment adder and a 20% small project adder. This is illustrated in Table 10 below, for baseline FIT pricing of 8¢/kWh.

Table 10: Example pricing for a 100 kWAC rooftop solar project

FIT pricing	Built environment adder (20%)	Small project adder for projects up to 100 kW (20%)	Final pricing for the FIT project
8¢/kWh	1.6¢/kWh	1.6¢/kWh	11.2¢/kWh

iii. Community benefit adder

To encourage the siting of local renewable energy projects in disadvantaged communities and on tax-exempt facilities, such as municipal properties, nonprofit facilities, public housing, and schools, it is recommended that the LSE offer a community benefit adder. The community benefit adder, of 5% on the baseline FIT pricing, will apply to any FIT project sited on a tax-exempt facility or located in a geographic area that is one of the 25% highest scoring census tracts in the CalEPA's CalEnviroScreen 3.0 tool, which is publicly available.[14] These are primarily in central San Diego south of I94 and west of I805, and in Otay Mesa in the southeast as shown in Figure 18 below. This rating is in alignment with how California Senate Bill 535 designates disadvantaged communities.[15]

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[14] "CalEnviroScreen 3.0," California's Office of Environmental Health Hazard Assessment, available at https://oehha.maps.arcgis.com/apps/webappviewer/index.html?id=4560cfbce7c745c299b2d0cbb07044f5, last visited on October 18, 2018.

[15] "SB 535 Disadvantaged Communities (2017)," California's Office of Environmental Health Hazard Assessment, available at http://oehha.maps.arcgis.com/apps/View/index.html?appid=c3e4e4e1d115468390cf61d9db83efc4, last visited on October 18, 2018.

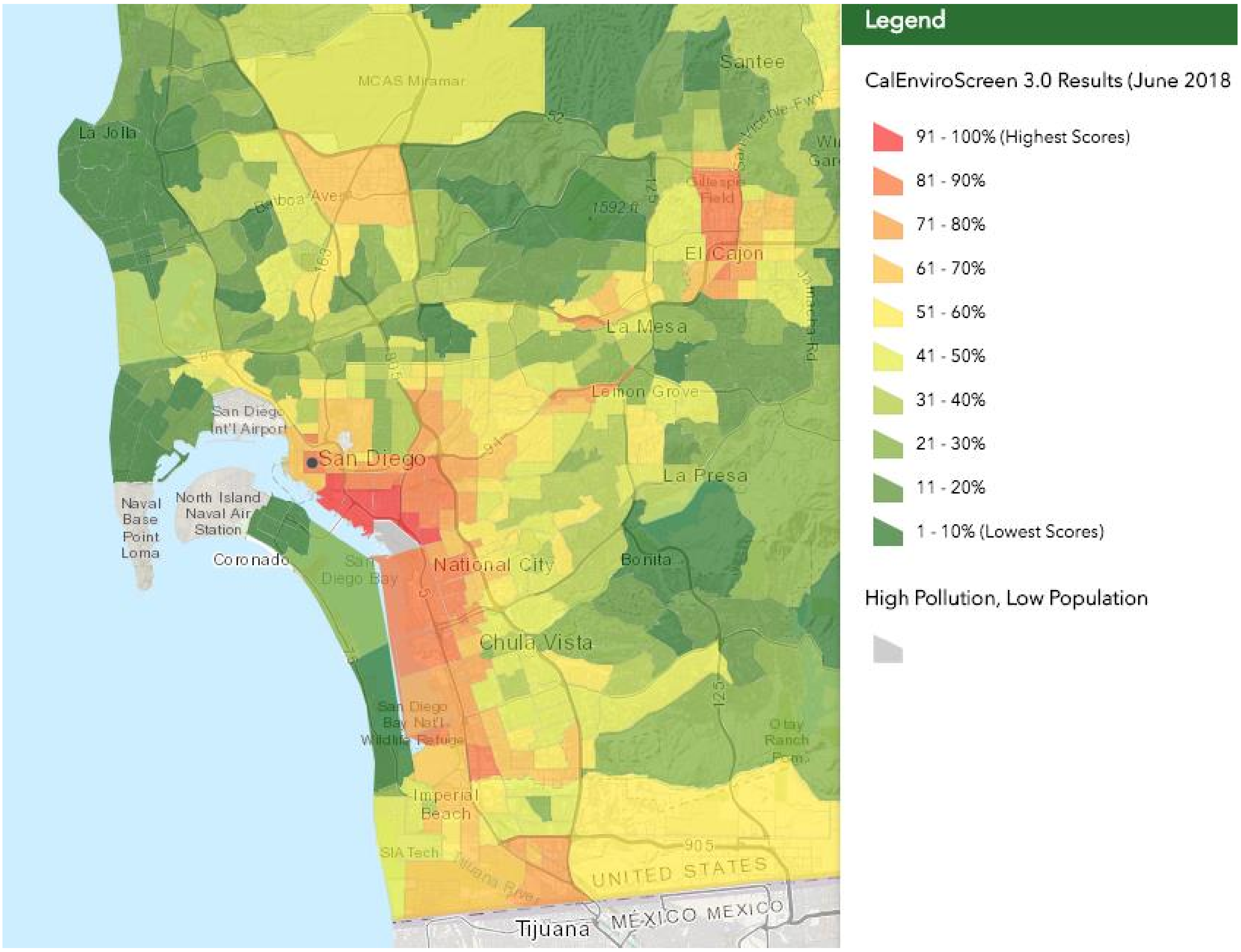

Figure 8: Map view of the City of San Diego using CalEnviroScreen 3.0

For example, a 100 kW_{AC} FIT project sited on a rooftop in an eligible CalEnviroScreen 3.0 community should receive the 20% built environment adder, a 20% small project adder, and a 5% community benefit adder. This is illustrated in Table 11 below, for baseline FIT pricing of 8¢/kWh.

Table 11: Example pricing for a 100 kWAC rooftop solar project sited in a CalEnviroScreen 3.0 disadvantaged community

FIT pricing	Built environment adder (20%)	Small project adder for projects up to 100 kW (20%)	Community benefit adder (5%)	Final pricing for the FIT project
8¢/kWh	1.6¢/kWh	1.6¢/kWh	0.4¢/kWh	11.6¢/kWh

The community benefit adder should apply only to projects sited on built environments and sized no larger than 1 MW, as larger projects are more likely to be economically viable without any pricing adders.

iv. Dispatchability adder

To encourage the development of energy storage within the City of San Diego, it is recommended that the LSE offer a dispatchability adder. This adder is a fixed ¢/kWh bonus, whereas the other adders (built environment, small project, and community benefit) are a percentage of the current baseline FIT PPA price.

Pairing local renewables with local energy storage can provide many benefits to the grid and associated value to the LSE. These benefits and values include:

- Making renewable energy dispatchable to match grid requirements and potentially reaping energy arbitrage and capacity value.
- Reducing peak congestion on the transmission and distribution grids and potentially reaping associated congestion relief value.
- Matching the energy supply and demand for a given LSE, including a CCE's forecasted versus real-time experience, and potentially reaping value from avoiding scheduling penalties, etc.

When an energy storage system is deployed in conjunction with an ITC-qualifying resource, the ITC can be applied to the cost of the entire system. In order to receive full ITC value, the energy storage system must be 100% charged by renewable energy. Otherwise, the ITC percentage is reduced on a straight-line basis until 75% of the charge is coming from renewables for 75% of the ITC value (at least 75% of the chare needs to come from renewables to be eligible for any ITC on the energy storage system). This means that the LSE can facilitate the ITC being leveraged and secure the benefits of energy storage at a lower cost than otherwise possible.

For an energy storage project to be eligible for the dispatchability adder, it must meet the following operational requirements:

- The energy storage power capacity must be rated at a minimum of 100 kW and a maximum of the nameplate capacity of the renewable energy project to which it is attached. For example, a 2 MW solar project can have a battery with a power capacity between 100 kW and 2 MW.
- The energy storage capacity must provide a minimum of two hours and a maximum of four hours of the nameplate power capacity. For example, a battery with a 1 MW power capacity can have the dispatchability adder apply to between 2 MWh and 4 MWh.
- The full amount of energy being paid the dispatchability adder must be available daily.
- The energy storage facility must follow the dispatch schedule provided by the LSE, with as little as one-hour advance scheduling, and the storage system must eventually be able to allow direct dispatch control per future LSE specifications.

Dispatchable renewables facility owners will be compensated daily via a 15¢/kWh dispatchability adder for their full kWh deliverability rating. This adder is paid based on the capacity that a project guarantees it can deliver on a daily basis. If the LSE calls for dispatch and a project is not able to deliver its promised capacity, a penalty may be enforced to deter such behavior. Any shortfalls from the contracted levels under the dispatchability adder must be for justifiable weather-driven or planned maintenance reasons. It is recommended that unjustified shortfalls be penalized 50 times the value of shorted amounts, and three or more unjustified shortfalls within a rolling 12-month period result in potential termination of the dispatchability adder for the offending facility — solely at the discretion of the LSE.

Table 12:Example pricing for a 3 MWAC solar project paired with a 3 MW / 6 MWh battery

Pricing component	Energy output (kWh/year)[16]	FIT pricing	Dispatchability adder	Final pricing for the delivered energy	Annual cost of energy for the LSE
Non-dispatchable	3,510,000	8¢/kWh	0¢/kWh	8¢/kWh	$280,800
Dispatchable energy	2,190,000	8¢/kWh	15¢/kWh	23¢/kWh	$503,700
Total	**5,700,000**			**13.76¢/kWh[17]**	**$784,500**

Pricing for the dispatchability adder is based on detailed analysis of AES's solar+storage project with Kauai Island Utility Cooperative[18], as well as IHS's April 2016 report titled *Following the Grid Storage Current: Technology, cost, and economics*. As Table 12 shows, IHS expects to see pricing in the 18-25¢/kWh range between 2020 and 2025 for lithium-ion energy storage. It is worth noting that this pricing does not consider the ITC benefit, which can be secured by pairing storage with an ITC-qualifying resource. It is expected that an adder of 15¢ for each dispatchable kWh delivered to the LSE will drive deployment of some energy storage capacity within the City of San Diego.

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[16] This assumes 1,900 kWh/kW/year of energy production, which is in line with solar resource quality assessment for the city of San Diego and used consistently throughout this report. Round-trip inefficiency of energy storage devices is not reflected in these figures but could have an impact of 10% or more for energy that goes in and out of the battery.

[17] This is the average price, in cents per kilowatt-hour, paid by the LSE for energy from this project.

[18] "AES' New Kauai Solar-Storage 'Peaker' Shows How Fast Battery Costs Are Falling," *Greentech Media,* January 16, 2017, available at https://www.greentechmedia.com/articles/read/aes-puts-energy-heavy-battery-behind-new-kauai-solar-peaker, last visited October 8, 2018.

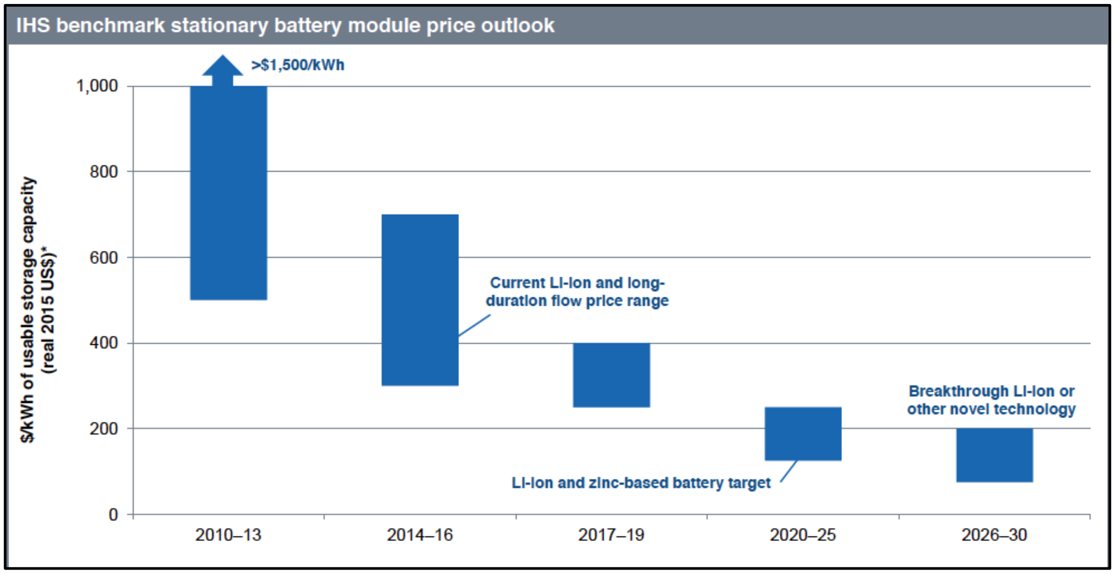

Figure 9: Pricing outlook for lithium-ion battery storage in the U.S.

Similarly, with the aforementioned FIT rate structures, MRP structure applies to the dispatchability adder. Such a mechanism could be designed to adjust the dispatchability adder (¢/kWh), either up or down, based on whether the market is able to deliver dispatchable renewable energy at the offered price. We recommend that the LSE allocate 6 MWh of program capacity each year, released in quarterly increments of 1.5 MWh, totaling 10 MWh by spring 2022. Through offering capacity in predictable, quarterly allocations, the LSE will drive an efficient dispatchability adder in the City of San Diego, sustained by MRP in order to reduce dispatchable energy pricing over time.

For example, a FIT using MRP for its dispatchability adder will allow the first 1.5 MWh of capacity to contract at a starting fixed price. If the first 1.5 MWh tranche fills quickly with projects, then the price paid for the following 1.5 MWh tranche is reduced by a predetermined adjustment. If, on the other hand, the first 1.5 MWh of available capacity is not procured within the planned time frame, then the fixed price adjusts upward by a predetermined increment after a set time period for the subsequent tranche.

The following guidelines detail our recommended dispatchability adder with an MRP mechanism for the LSE's FIT program:

Downward price adjustment

- If valid applications exceeding 2.25 MWh (150% of 1.5 MWh, the desired quarterly capacity) have been reserved as of 30 days prior to the next scheduled quarterly procurement, then there is a downward price adjustment of 1.5¢.
- If valid applications totaling between 1.5 MWh and 2.25 MWh (100-150% of desired quarterly capacity) have been reserved as of 30 days prior to the next scheduled quarterly procurement, then there is a downward price adjustment of 1¢.

No price adjustment

- If valid applications totaling between 0.9 MWh MW and 1.5 MW (between 60% and 100% of desired quarterly capacity) have been reserved as of 30 days prior to the next scheduled quarterly procurement, no price adjustment is made.

Upward price adjustment

- If valid applications totaling less than 0.9 MWh (less than 60% of desired quarterly capacity) have been reserved as of 30 days prior to the next scheduled quarterly procurement, then there is an upward price adjustment of 0.5¢.

Figure 10 illustrates the potential MRP adjustments for a dispatchability adder over the first few allocations of the LSE's FIT, with the price adjustments based on market response.

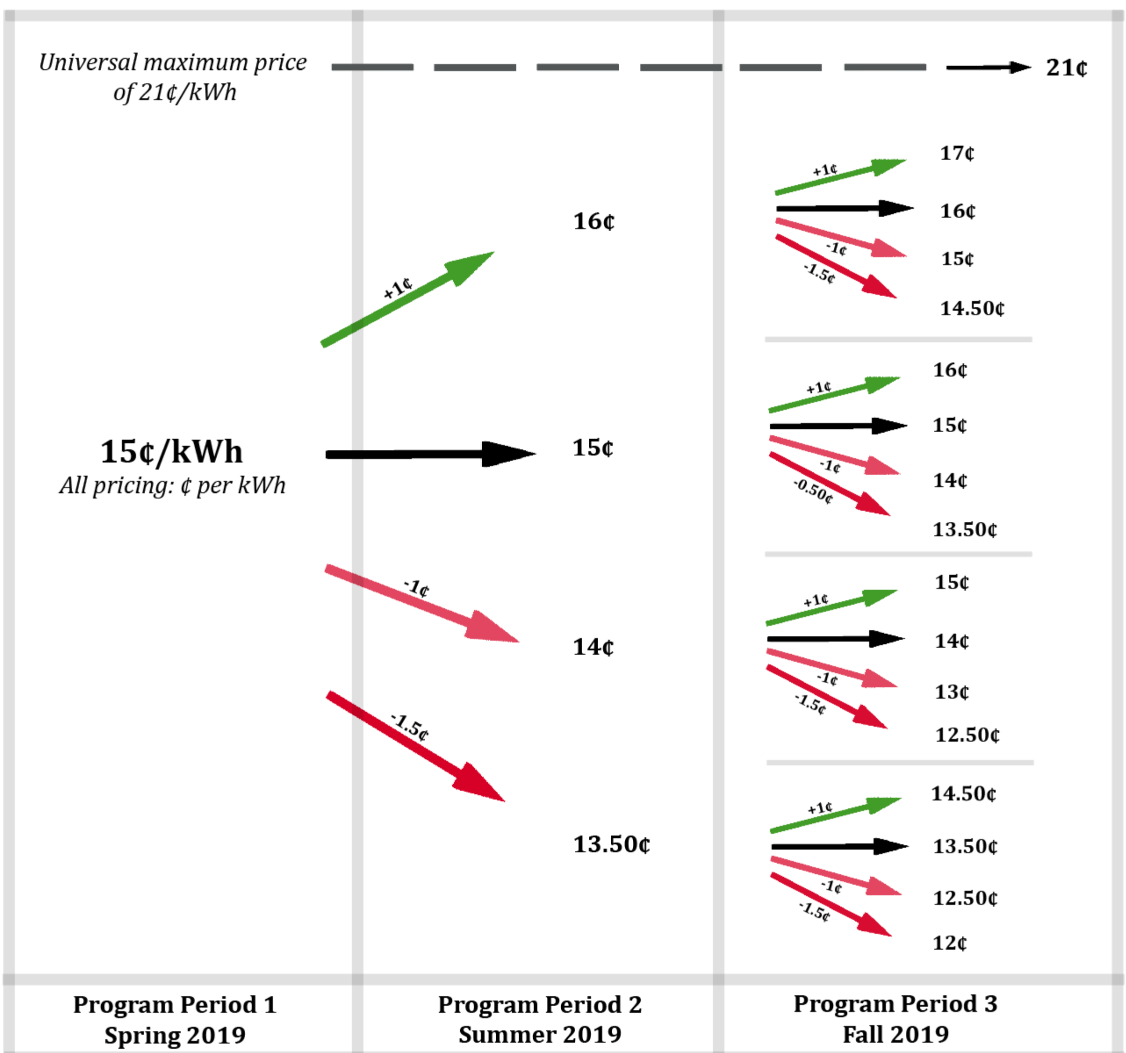

Figure 10: Market Responsive Pricing (MRP) base line for the dispatchability adder

Note that the pricing adders are added to this FIT price. Table 13 illustrates the PPA price for a solar FIT project that qualifies for the built environment, small project, and community benefit adders — on top of the universal maximum FIT price of 9.5¢/kWh. The total price for this project would be 13.78¢/kWh.

Table 13: Universal maximum price, shown for a 100 kWAC rooftop solar project on a tax-exempt facility

Universal maximum FIT price	Built environment adder (20%)	Small project adder for projects up to 100 kW (20%)	Community benefit adder (5%)	FIT pricing for the project
9.5¢/kWh	1.9¢/kWh	1.9¢/kWh	0.48¢/kWh	13.78¢/kWh

If this project includes a 100 kW / 200 kWh energy storage system, the pricing will increase, as the dispatchability adder of 15¢ is added onto all the energy that is contracted to be delivered from the energy storage system. Table 14 below details the total price for energy from this solar+storage project, which is 19.54¢/kWh.

Table 14: Universal maximum price, shown for a 100 kWAC rooftop solar project on a tax-exempt facility with a 100 kW / 200 kWh energy storage system

Pricing component	Energy output (kWh/year)[19]	FIT price[20]	Dispatchability adder	Final pricing for the delivered energy	Annual cost of energy for the LSE
Non-dispatchable	117,000	13.78¢/kWh	0¢/kWh	13.78¢/kWh	$16,123
Dispatchable energy	73,000	13.78¢/kWh	15¢/kWh	28.78¢/kWh	$21,009
Total	**190,000**			**19.54¢/kWh[21]**	**$37,132**

The LSE will ultimately determine the level of local procurement based on the budget available to support a local procurement premium, and the associated procurement targets will limit the LSE's total contract cost commitments. Signaling an upper limit for pricing through a universal pricing maximum will help the LSE quantify the upper limit for the FIT program budget requirement.

[19] This assumes 1,900 kWh/kW/year of energy production, which is in line with solar resource quality for the City of San Diego and used consistently throughout this report.
[20] Based on a universal maximum FIT price of 9.5¢/kWh, as well as the full built environment, small project, and community benefit adders, as shown in Table 13.
[21] This is the average price, in cents per kilowatt-hour, paid by the LSE for energy from this project.

m. Price components and sensitivity

PV project development and operation costs have numerous components, as outlined below. Module and inverter costs, typically comprising 25% of the total installed project cost, reflect global and national markets and are not generally affected by local conditions. Balance of system (BOS) costs, installation, engineering, and permitting comprise roughly 20% of the total project costs and can increase for rooftops with special constraints. The range of variability within BOS costs is unlikely to exceed 10% of the total project cost. Labor costs, while significant, are a relatively small contributor to total costs. While prevailing wage standards may add 50-80% to the base labor cost component, this represents a 5% variable in the total energy costs, adding 0.25-0.5¢/kWh.

The costs for interconnecting local renewable projects to SDGE's grid can vary widely, and expensive grid upgrades can be triggered as the added capacity of a proposed project crosses threshold constraints specific to each circuit or line section. Upgrades are more likely to be triggered as participation levels increase and available grid capacity and preferred siting opportunities are filled. Avoiding the most expensive 10% of interconnections, which represent non-viable proposals, both the mean and median interconnection cost has been approximately $100,000 per MW in the SDG&E service area, with a standard deviation of $70,000. While significant, even a threefold increase in interconnection costs will contribute less than 15% of the total 20-year costs to the system owner that must be recouped through energy sales, as reflected in the PPA price. It is important to note that very substantial commercial-scale PV can be developed without exceeding the available hosting capacity on any circuit or line section, as reflected in our Solar Siting Survey, thereby indicating that interconnection costs should be minimized to between $50,000 and $70,000 per MW.

Our preliminary analysis indicates that much higher penetration levels of local solar PV will not trigger substantially higher costs on many circuits associated with commercial facilities, and these siting opportunities are widely available in the City of San Diego. Larger ground-mounted systems face proportionately higher interconnection costs, but these projects can offset those costs through higher energy production and other savings related to economies of scale.

If structural upgrades or early roof replacement are necessary before a solar PV project can be installed, this can be a substantial additional cost. Such upgrades are more commonly required on older, light-industrial sites where site lease rates are typically lowest. As increasing levels of FIT participation are sought, these costs are more likely to be encountered, and the total cost of a lease combined with these upgrades will be competing with higher lease costs demanded by other building or site owners. Parking lot installations already exemplify this trade-off. BOS costs for PV panel supports and labor are higher for parking lots than for PV-ready rooftops, and the lower reported site leasing costs for parking lots reflect both the added system owner costs and the site improvement value offered by the shade from a solar PV canopy.

The remaining major cost contributors are the developer margin and overhead, costs associated with locating and securing rights to a project site, and the cost of leasing that site. Developer margin and overhead costs, which include any associated development financing costs, contribute approximately 20% to the typical total project cost. While initial site acquisition requires increased effort as the supply becomes constrained, this is not a major cost contributor, and site availability is not expected to greatly influence significant developer costs and margins. While higher margins will certainly attract greater developer interest, these cost contributors will remain subject to market competition, and the supply of developers is not likely to become constrained regardless of participation rates in the program.

Figure 11 below illustrates the relative cost factors for a 1 MW fixed-tilt rooftop solar PV system.

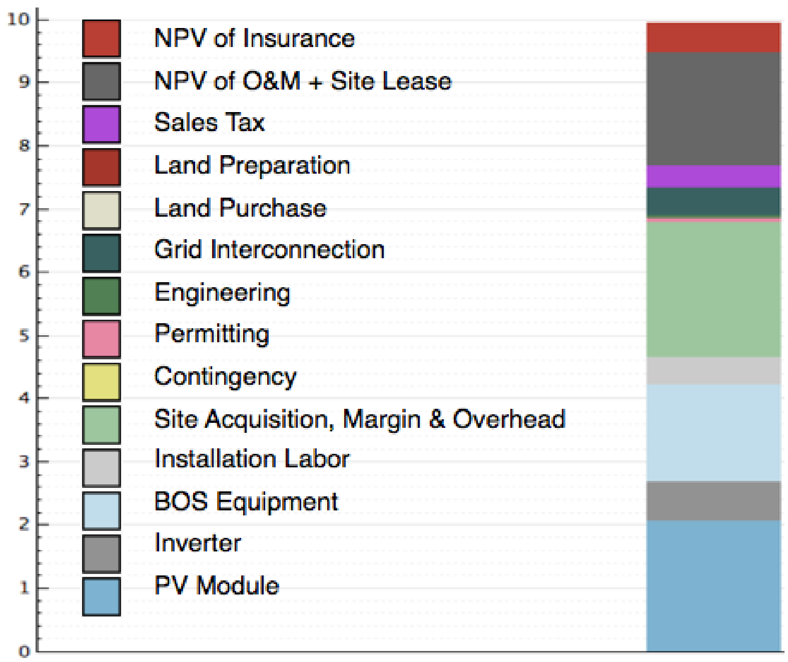

Figure 11: Relative project cost contributors for a 1 MW fixed-tilt rooftop PV system

n. Costs associated with participation rates

As higher FIT participation rates are sought, overall costs and required PPA rates increase. Site lease value is highly correlated with participation, defining a classic supply-demand curve. Interconnection costs also increase with participation rates but are driven by technical rather than market factors. These costs may be mitigated by utility grid modernization and distributed energy hosting capacity enhancement policies currently under development and regulated by the California Public Utilities Commission (CPUC). Property owners will be increasingly motivated to make their rooftops available as the site lease payments increase. However, income from site leasing must be recognized as a minor component of the property value, representing 1-2% additional income.[22] As a result, very substantial increases in leasing rates may be required to attract site owner participation

[22] A 100,000-square-foot rooftop will accommodate approximately 500 kW of solar PV capacity. Site leasing for solar PV at $50 per kW will yield $25,000 in annual lease revenues, or $0.25 per square foot. This contrasts with lease rates of $10 per square foot in 2012 for industrial space, $20 for office space, and $23 for retail.

rates in excess of 20%. This may be mitigated by experience as the market matures, and by effective informational outreach efforts to commercial property owners by the LSE and local governments to build awareness and set expectations. As noted above, sites burdened with necessary structural or interconnection upgrades become economically viable in light of increasing leasing costs associated with higher participation. These cost components are fully substitutable.

Installed solar PV requires roughly 200 square feet per kW. For example, a 100,000-square-foot rooftop will accommodate approximately 500 kW of solar PV capacity. Therefore, site leasing at $50 per kW will yield $25,000 in annual lease revenues, or $0.25 per square foot. Each $15/kW in annual lease costs contributes 1¢/kWh to the required PPA rate, as shown below in Table 15.

Table 15: Projected lease rate relative to rooftop market participation and PPA price

Participation rate (% of local generation potential realized)[23]	Required PPA rate (¢/kWh)	Average site lease rate ($/kW/yr)[24]	Average site lease rate ($/square foot/yr)[25]	Site lease impact on base PPA rate (¢/kWh)	Site lease cost factor (% of PPA rate)
1%*	7¢*	*	*	*	*
2%	9¢	*	*	*	*
5%	11¢	$0**	$0	0¢	0%
11%	13¢	$15	$0.075	1¢	7%
22%	15¢	$45	$0.225	3¢	19%
36%	17¢	$75	$0.375	5¢	28%
52%	19¢	$105	$0.525	7¢	35%
66%	21¢	$135	$0.675	9¢	41%
75%	23¢	$165	$0.825	11¢	46%
82%	25¢	$195	$0.975	13¢	50%
87%	27¢	*	*	*	>50%
100.0%	Max				

* The margin of variability in this range exceeds predictive significance.
** A $0 site lease rate implies that the building owner is also the PV project owner and is utilizing existing property to derive income from the sale of energy.

[23] These numbers are derived from a UCLA Luskin Center study of Los Angeles solar potential and associated methodology, which assessed the economic potential and price elasticity of a feed-in tariff market response rate. Using the same price elasticity profiles, we applied this to the City of San Diego solar irradiance and 2017 pricing data. The UCLA report is available at http://innovation.luskin.ucla.edu/content/bringing-solar-energy-los-angeles-assessment-feasibility-and-impacts-basin-solar-feed-tari-0, last visited on October 18, 2018.
[24] Average observed rooftop lease rates of $30-50/kW in major California metropolitan areas constitute a 12% contribution to the total wholesale price of energy reflected in the PPA rate. These observed lease rates are seen today in a market in which less than 5% of the potentially available commercial rooftops are participating.
[25] Installed solar PV requires roughly 200 square feet per kW.

In cities such as Irvine, Palo Alto, and San Francisco, reported and projected lease rates for local PV procurement programs have been high due to price expectations by site owners and the limited availability of potential commercial sites. The City of San Diego has far greater large commercial-scale solar siting capacity; however, price expectations are not well understood by building owners and managers. Adjusting for this difference, site leasing costs of $40/kW will be expected to constitute 20% of the total PPA pricing required to secure 100 MW of PV development in built environments, approaching a 20% realization rate of the available technical commercial rooftop potential that has been identified through the Clean Coalition's Solar Siting Survey.

Additionally, net energy metering (NEM) project development will compete for allocation of the remaining commercial solar siting opportunities and should be included in the participation rate totals. The LADWP experience with both commercial NEM and the wholesale FIT 100 commercial rooftop programs provides some indication, as 17 MW of commercial NEM projects were added during the initial two-year period in which the FIT 100 program was active. While comparison against wholesale procurement is highly dependent upon the FIT price offered, if we extrapolate the rate of NEM uptake in SDG&E territory, we can anticipate the additional NEM participation rate during the 2018-2020 period to be on the order of 2%. This will marginally reduce the number of available siting opportunities and will offer full retail price value for the energy produced. NEM is generally only deployed on owner-occupied buildings and limited to the on-site load. Therefore, while NEM will compete for participation, it is not expected to have a major impact on the PPA pricing required to reach participation rates necessary to significantly contribute to the LSE's desired FIT procurement.

o. Nearby FIT pricing info

For reference, below are details on LADWP's FIT Program.

Through its SetFIT 100 and BlockFIT 50 Pricing Program, LADWP offers a 20-year fixed price of 13-17¢/kWh.

- The SetFIT 100 originally launched 100MW over five allocations beginning in February 2013 and lasting until February 2015. The SetFIT started with its first allocation at 17¢/kWh and decreased by 1¢/kWh in each allocation, ending at 13¢/kWh in the fifth allocation.
- The Block FIT 50 originally launched 50MW over three allocations starting with its first in June 2015 and ending with its third in December 2016. The Block FIT 50 is set to be more suitable to applicants with experience in developing larger projects.

On June 30, 2017, the LADWP's FIT Program began accepting applications for a 65 MW FIT Reoffer[26] of remaining capacity from FIT 100 and FIT 50, which includes 35 MW at a new fixed rooftop price of 14.5¢/kWh, and 30 MW in a competitively bid component, as well as other program enhancements.

[26] 65 MW FIT Reoffer, Los Angeles Department of Water and Power, available here, last visited October 18, 2018.

IV. Program budget

The budget required for the LSE's FIT program will depend on two factors: program size and program pricing.

p. Minimum budget requirements

The minimum annual FIT budget requirement for our recommended initial program of 7.5 MW is $1,140,000. which is detailed in Table 16 below. The program budget is determined by multiplying the FIT rate by the expected number of kWh procured annually through the FIT. This budget assumes all 7.5 MW of capacity are filled at a rate of 8¢/kWh and annual production of 1,900 kWh/kW/year of FIT capacity, which is the expected production from single-axis ground-mounted solar PV systems in the City of San Diego.

Table 16: Minimum budget required for initial 7.5 MW FIT program capacity

Program capacity	Expected annual FIT generation (kWh/year)	FIT PPA price (¢/kWh)	FIT program budget required
7.5 MW	14,250,000 kWh	8¢	$1,140,000
5 MW	9,500,000 kWh	8¢	$760,000

The required FIT budget will change if project developers design projects that qualify for any, or all, of the adders: built environment, small project, community benefit, and dispatchability. Table 17 below illustrates the required budget per 7.5 MW tranche, if 10% of allocated capacity receives an average of a 20% adder.

Table 17: Budget required for 7.5 MW of FIT capacity, with a baseline price of 8¢/kWh, and with 10% of capacity receiving an average adder of 20%

% of allocated capacity	Capacity	Expected annual FIT generation (kWh/year)	PPA price (¢/kWh)	Budget required
90%	6.75 MW	12,825,000 kWh	8¢	$1,026,000
10%	0.75 MW	1,425,000 kWh	9.6¢	$136,800
Total	**7.5 MW**	**14,250,000 kWh**	**8.16¢**[27]	**$1,162,800**

An additional $22,800 is required in this scenario (compared to the scenario in Table 16), in which 0.75 MW of FIT program capacity is filled by projects that receive an average adder of 20%. The average price per kWh paid by the LSE in this scenario is 8.16¢/kWh.

[27] This is the average price, in cents per kilowatt-hour, paid by the LSE for energy in this 7.5 MW tranche.

Table 18 below illustrates the required budget per 7.5 MW tranche, if 50% of allocated capacity receives an average adder of 20%.

Table 18: Budget required for 7.5 MW of FIT capacity, with a baseline price of 8¢/kWh, and with 50% of capacity receiving an average adder of 20%

% of allocated capacity	Capacity	Expected annual FIT generation (kWh/year)	PPA price (¢/kWh)	Budget required
50%	3.75 MW	7,125,000 kWh	8¢	$570,000
50%	3.75 MW	7,125,000 kWh	9.6¢	$684,000
Total	**7.5 MW**	**14,250,000 kWh**	**8.8¢**[28]	**$1,254,000**

An additional $114,000 is required in this scenario (compared to that in Table 16), in which 3.75 MW of FIT program capacity is filled by projects that receive an average adder of 20%. The average price per kWh paid by the LSE in this scenario is 8.8¢/kWh.

Table 19 below illustrates the required budget per 7.5 MW tranche, if 50% of allocated capacity receives an average adder of 50%.

Table 19: Budget required for 5 MW of FIT capacity, with a baseline price of 8¢/kWh, and with 50% of capacity receiving an average adder of 50%

% of allocated capacity	Capacity	Expected annual FIT generation (kWh/year)	PPA price (¢/kWh)	Budget required
50%	3.75 MW	7,125,000 kWh	8¢	$570,000
50%	3.75 MW	7,125,000 kWh	12¢	$855,000
Total	**5 MW**	**14,250,000 kWh**	**10¢**[29]	**$1,425,000**

An additional $285,000 is required in this scenario (compared to that in Table 16), in which 3.75 MW of FIT program capacity is filled by projects that receive an average adder of 50%. The average price per kWh paid by the LSE in this scenario is 10¢/kWh.

q. Budget sensitivity

The LSE's FIT budget will vary depending on program size and pricing. Table 20 below illustrates the required budget for a suite of tranche sizes with average pricing ranging from 7¢/kWh to 13¢/kWh.

[28] This is the average price, in cents per kilowatt-hour, paid by the LSE for energy in this 7.5 MW tranche.
[29] This is the average price, in cents per kilowatt-hour, paid by the LSE for energy in this 7.5 MW tranche.

Table 20: Budget required for FIT capacity at various tranche sizes and pricing levels

Tranche size (MW)	Expected annual FIT generation (kWh/year)	Average Fit PPA price (¢/kWh)	Annual budget required
3.75 MW	7,125,000 kWh	7¢	$498,750
3.75 MW	7,125,000 kWh	8¢	$570,000
3.75 MW	7,125,000 kWh	9¢	$641,250
3.75 MW	7,125,000 kWh	10¢	$712,500
3.75 MW	7,125,000 kWh	11¢	$783,750
3.75 MW	7,125,000 kWh	12¢	$855,000
3.75 MW	7,125,000 kWh	13¢	$926,250

Tranche size (MW)	Expected annual FIT generation (kWh/year)	Average Fit PPA price (¢/kWh)	Annual budget required
7.5 MW	14,250,000 kWh	7¢	$997,500
7.5 MW	14,250,000 kWh	8¢	$1,140,000
7.5 MW	14,250,000 kWh	9¢	$1,282,500
7.5 MW	14,250,000 kWh	10¢	$1,425,000
7.5 MW	14,250,000 kWh	11¢	$1,567,500
7.5 MW	14,250,000 kWh	12¢	$1,710,000
7.5 MW	14,250,000 kWh	13¢	$1,852,500

Tranche size (MW)	Expected annual FIT generation (kWh/year)	Average Fit PPA price (¢/kWh)	Annual budget required
15 MW	28,500,000 kWh	7¢	$1,995,000
15 MW	28,500,000 kWh	8¢	$2,280,000
15 MW	28,500,000 kWh	9¢	$2,565,000
15 MW	28,500,000 kWh	10¢	$2,850,000
15 MW	28,500,000 kWh	11¢	$3,135,000
15 MW	28,500,000 kWh	12¢	$3,420,000
15 MW	28,500,000 kWh	13¢	$3,705,000

r. Program budget over time

As the FIT expands over time, the annual budget required to pay for additional capacity will grow. The exact budget will depend on how much new program capacity is established, as well as the pricing offered for the new capacity, and the percentage of FIT projects that qualify for adders. Table 21 below shows the required budget for a 50 MW FIT program at an average price of 8¢/kWh. Note that the annual program budget requirements trail behind capacity allocation. This is because, as previously discussed, there is roughly an 18-month lag time between when the LSE releases capacity to the market and when that capacity begins delivering power to the LSE.

Table 21: Estimated budget requirements as FIT program capacity expands, with an average FIT PPA price of 8¢/kWh

Capacity allocation date	Capacity allocation (MW)	Estimated commercial online date (COD)[30]	Annual incremental budget required for allocation[31]	Total annual incremental program budget retail sales[32]
Spring 2019	7.5 MW	Fall 2020	$0	$0
Summer 2019	7.5 MW	Winter 2020	$0	$0
Fall 2019	7.5 MW	Spring 2021	$0	$0
Winter 2019	7.5 MW	Summer 2021	$0	$0
Spring 2020	7.5 MW	Fall 2021	$0	$0
Summer 2020	7.5 MW	Winter 2021	$0	$0
Fall 2020	5 MW	Spring 2022	$1,140,000	$1,140,000
Winter 2020	0 MW	n/a	$1,140,000	$2,280,000
Spring 2021	0 MW	n/a	$1,140,000	$3,420,000
Summer 2021	0 MW	n/a	$1,140,000	$4,560,000
Fall 2021	0 MW	n/a	$1,140,000	$5,700,000
Winter 2021	0 MW	n/a	$1,140,000	$6,840,000
Spring 2022	0 MW	n/a	$760,000[33]	$7,600,000
Summer 2022	0 MW	n/a	$0	$7,600,000
Total	**50 MW**			**$7,980,000**

[30] Assuming a total lag time of 18 months from capacity release to build FIT projects — 6 months for the application process and PPA execution, and then 12 months to bring the project online.
[31] This budget assumes an average FIT rate of 8¢ and annual production of 1,900 kWh_{AC}/kW/year of FIT capacity. The increase in FIT program budget is based on the capacity allocation date.
[32] Based on the commercial online date of FIT projects — not the capacity allocation date.
[33] This is the annual incremental budget required for a 5 MW allocation, shown in Table 16.

In this instance, the annual FIT budget would remain at $7,600,000 until summer 2042, when the first projects reach the end of their 20-year contract term. At this point, the budget would decrease by $1,140,000 each quarter, as 7.5 MW of FIT contracts expire quarterly.

Of course, if the LSE is a CCA, the expansion of the LSE's FIT will likely depend on the rate at which the LSE grows its customer base and has budget available to support local renewables generation.

V. Policies and procedures

This section offers high-level recommendations on FIT program policies and procedures. Lessons learned and pro formas from existing FIT programs are referenced.

s. Program application

The application process should require enough information to enable the LSE staff to thoroughly evaluate the viability of a proposed project without being unnecessarily onerous on program participants. Key details include:

- Evidence of emerging site control, which can come in the form of a standardized letter of intent signed by the project developer and property owner
- Proof of the ability to develop, finance, and construct within 24 months[34]
- Technical and engineering aspects
- A history of successful renewable energy project management and development

It is recommended that that the LSE require a non-refundable application fee and a refundable "per kW performance deposit." This will ensure a more efficient program by deterring non-viable bids from clogging the lottery and project queue. Sonoma Clean Power, under its ProFIT program, requires a non-refundable application fee of $500 and a performance deposit, which is fully refundable upon project completion.[35] It is believed that a $500 application fee and performance deposit around $40/kW$_{AC}$ would be effective for the LSE FIT application process.

Below are a number of FIT application pro formas:

- MCE (0-1 MW) (>1-5 MW)
- Sonoma Clean Power
- City of Palo Alto Utilities

[34] MCE requires financial statements for project participants (developer and financier, in particular); a PG&E Generating Facility Interconnection Application and PG&E notice of complete application; a copy of the application for RPS certification (from the California Energy Commission) and assigned pre-certification number, if available; and evidence of environmental compliance review/notice of determination receipt.

[35] *Feed-in Tariff*, Sonoma Clean Power, available at https://sonomacleanpower.org/power-sources, last visited January 17, 2019.

t. Project queuing

The LSE needs to clearly define, in advance, how applications will be handled. It is recommended that the FIT program start with a two-week open application period. At the end of the open application period, a lottery system should be used to determine the order in which projects will be listed in the queue. All applications submitted after the open application period should be accepted on a first-come-first-served basis. If an application submitted to participate in an open tranche (tranche 1) is not selected, then those complete and valid application should automatically roll into the next tranche (tranche 2).

Once the LSE accepts an application, the project developer should have a set amount of time, ideally 15-30 days, to officially move the proposed project into the FIT program queue. Once a project moves into the queue, the stated capacity of the project should be officially reserved in the program. The performance deposit, which should be around $40/kW_{AC}$, becomes non-refundable if a project in the queue does not meet agreed-upon milestones, including its COD.

u. Contracts

There should be a standard PPA between the LSE and a renewable energy facility owner to purchase energy at a predefined, fixed rate for a long duration. The standardized PPA should fulfill the needs of all relevant parties in the simplest fashion possible. The key parties are the LSE, the developers, and the project investors (including lenders).

An optimal PPA is simple enough to minimize the review effort by developers and investors, yet substantial enough to avoid potential disputes and provide clear procedures for resolving disputes if they do occur. The level of complexity of the form will depend on the complexity of the program. For example, the Gainesville Regional Utilities PPA contains only 18 pages, while the Sacramento Municipal Utility District PPA consists of 49 pages.

The standard agreements should be circulated for review by likely project developers and potential investors to ensure that the PPA is straightforward, financeable, and fair to the LSE, project developers, and project investors.

Key provisions of an effective FIT PPA are detailed below.

Contract Provision	Overview
Length	This specifies the length of a contract term between the LSE and the project owner. Well-designed FIT programs offer terms of at least 20 years, and sometimes longer. Generally, the longer the contract length, the lower the fixed price offered. Contract length is an essential feature of a FIT that makes it possible for developers to secure financing at reasonable rates and protects LSE customers against rising electricity prices.
Performance excuses	This specifies under what circumstances a FIT project is penalized, or not penalized, for not being able to deliver electricity as expected, as well as the timeline for a project owner to resolve performance issues. Since FIT project owners are compensated only for delivered energy, they are inherently motivated to promptly resolve performance issues. It is also common to define when the purchaser is not responsible for buying electricity from a FIT facility. Without capping exceptions, it is possible for project financing to become far more difficult. O&M plan?
Environmental attributes	This section details ownership of the environmental or renewable energy attributes of the purchased electricity. This includes: (i) proof that the renewable energy is certified as an eligible resource that meets state and/or local requirements; (ii) conveyance of all renewable energy attributes, such as RECs; and (iii) any reporting obligations necessary to meet state and/or local requirements.
Project milestones timeline	This provides deadlines for submitting proof of permit applications, engineering drawings, equipment orders, and commercial operation date. Firm, reasonable deadlines ensure that projects proceed as committed. Projects that are not proceeding in a timely fashion may be removed from the queue. It is common for timelines to reasonably accommodate all good-faith applicants and allow for events that are not under the control of the project developer, such as natural disasters.
Assignment	This specifies if a contract can be assigned to any new owner that meets program eligibility criteria. In effect, allowing assignment enables program participation by potential facility owners that may sell the facility and/or the real property where the facility is located during the term of the contract.
Form of lender consent	A standard form for lender consent adds consistency and streamlines a FIT program, as it avoids negotiating individual lender consent agreements for each project. A standard lender consent form if often included as part of the standard contract.

More information on FIT contract provisions is available on the Clean Coalition website.[36] Below are FIT program PPA examples:

- Sacramento Municipal Utility District
- City of Palo Alto Utilities
- Los Angeles Department of Water & Power
- MCE

The Clean Coalition worked closely with the City of Palo Alto and its municipal utility to open City-owned properties to solar installations. Through this effort, a lease agreement for siting solar on municipal properties was developed; it is available to the LSE for reference.

VI. Anticipated challenges

[36] "Local CLEAN Program Guide: Module 6," Clean Coalition, available at http://www.clean-coalition.org/site/wp-content/uploads/2012/10/Local-CLEAN-Program-Guide-Module-6-Designing-CLEAN-Policies-Procedures-SSW_21-12-June-2012.pdf, last visited October 10, 2018.

Based on the experience of other FIT programs nationwide, below are anticipated challenges the LSE may face.

v. Interconnection

Interconnection of FIT projects can be a lengthy and expensive process. The timeline, costs, and uncertainly involved in interconnection can be reduced through active support from the local utility, which in this case is SDG&E. It is recommended that the LSE has proactive engagement with SDG&E staff to streamline interconnection to the extent possible. One key step for the LSE is to identify feeders and line segments within SDG&E's grid, where new local capacity will be quickest and easiest to interconnect. Much of this information is now available due to the Distribution Resources Planning effort spearheaded by the Clean Coalition. Direct access to SDG&E's RAM interconnection map is currently available,[37] and more detailed hosting capacity data will be available through the Integration Capacity Assessment data scheduled to be released at the end of 2018. This information was used in the Solar Siting Survey created in association with this report to identify locations with adequate hosting capacity and the quantity of PV that can be interconnected without requiring significant distribution upgrades.

w. Property owner participation

There is large potential for the installation of solar PV systems on commercial and industrial properties. However, building owners often have concerns regarding solar installations on their facilities, and these concerns fall into five major areas.

1) Economic considerations: Building owners are concerned about the cost of the system, as well as ongoing operations and maintenance (O&M) costs.

2) Outside core business area: Building owners see solar as a distraction to their core business area.

3) Facility concerns: Building owners see solar installations as a facility liability.

4) Vendor and technology risk: Building owners have expressed concern regarding the reliability of solar developers — with respect to workmanship, project management, and length of time in business.

5) Permitting and approvals: Building owners do not want to navigate the permitting and approval process for a solar installation. Additionally, some building owners need approval from the landowner to make significant modifications.

[37] https://www.sdge.com/more-information/customer-generation/renewable-auction-mechanism-ram-map-0, and https://www.sdge.com/more-information/customer-generation/enhanced-integration-capacity-analysis-ica

The Clean Coalition created the Solar Solutions Guide to address these building owner concerns, and this guide is available at www.clean-coalition.org/resource/solar-solutions-guide/.

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Appendix – pricing analysis assumptions

Below are our assumptions for the System Advisory Model (SAM) pricing analysis.

Location	Type of system	Size of solar PV system (W_{AC})	Installed cost ($/$W_{DC}$)	Initial output (kWh/ kW_{DC}/yr)	20-year fixed PPA price with sales tax	20-year PPA price (real $)[38] with sales tax	20-year fixed PPA price No sales tax	20-year PPA price (real $)[39] No sales tax
San Diego	Built environment	100 kW roof	$2.19	1655	14.3¢	11.9¢	13.9¢	11.5¢
San Diego	Built environment	350 kW roof	$2.02	1655	13.4¢	11.1¢	12.9¢	10.7¢
San Diego	Built environment	500 kW roof	$1.96	1655	13.1¢	10.9¢	12.7¢	10.5¢
San Diego	Built environment	1 MW	$1.81	1655	12.4¢	10.3¢	12.0¢	10.0¢
San Diego	Ground-mount	1 MW tracking	$1.76	2065	9.8¢	8.1¢	9.6¢	7.9¢
San Diego	Ground-mount	3 MW tracking	$1.70	2065	9.5¢	7.9¢	9.3¢	7.7¢

x. Modeling assumptions

- NREL System Advisor Modeling performed with PVWatts system design standards.
- Installed cost is turnkey cost per nameplate capacity for completed interconnected system delivering power to the grid, including all permits, fees, taxes, administrative costs, overhead and margin for projects with assumed 50% debt ratio. Installed costs vary with market maturity (date, size, market development).
- Analysis includes no escalator and no residual value after 20-year term of PPA.
- Renewable Energy Credits (RECs) are bundled with energy sales.
- Internal Rate of Return (IRR): 8%.
- DSCR 1.3 (50% debt financing of project development costs, excluding site lease).
- Interest rate on debt: 6%.
- Nominal discount rate: 8% (6% real + 2% inflation).
- Federal depreciation: MACRS 5-year (without bonus option).
- Federal income tax rate: 35%.
- Federal Investment Tax Credit (ITC): 30%.
- O&M: $15/kW/yr for fixed-tilt rooftop.
- Inverter replacement reserve: $20/kW/yr.
- Interconnection costs: Urban $70,000/$MW_{DC}$, including gen-tie and system upgrades, assuming siting to existing grid capacity; rural $200,000/MW.
- Insurance costs: 0.5%.
- Total system losses: 11.5%.

[38] Constant 2018 dollar value, levelized rate assuming 2% inflation.
[39] No sales tax per California Assembly Bill 398 (2017).

Location-specific assumptions

- System output based on NREL's TMY solar resource value, Montgomery-Gibbs Airport 32.817 °N, -117.133 °E.
- Rooftop installation at 20º fixed tilt, ground mount with single-axis tracking.
- Flat Rate — no Time of Delivery price adjustment.
- Site rental: $40,000/MW/yr (20% of FIT project revenue over its 20-year lifespan).
- State corporate income tax rate: 8.84%.
- State tax benefits: MACRS schedule (§171.107).
- Sales tax: 9.25% — Adjust to 7.75%, confirm AB 398 exemption.
- Property tax: 0%.
- Debt and tax equity financing rates can affect results if they differ from the IRR.

Potential adjustments influencing PPA price

For a baseline pricing of 9¢/kWh:

- Installed cost +/- 25¢/W: 1.1¢/kWh
- Site rental costs +/- $15,000: 1.0¢/kWh
- Labor Prevailing Wage reqmt: 0.3¢/kWh
- PPA term 25 years: - 0.5¢/kWh
- Add PPA escalator @ 1%: - 0.8¢/kWh starting price reduction
- IRR target +/- 1%: 0.2¢/kWh (subject to debt assumptions)
- O&M cost +/- $5/kW-yr: 0.4¢/kWh
- Inflation Rate +/- 1%: 0.4¢/kWh
- Interest Rate +/- 1% 0.4¢/kWh
- BOS cost +/- 20% 0.3¢/kWh
- Grid Interconnection +/- 5¢/W 0.2¢/kWh
- Installer Margin & Overhead +/- 20% 0.4¢/kWh
- Sales tax exemption[40] 0.5¢/kWh

[40] California Assembly Bill 398 included a provision to exempt renewable electric generation facilities from sales tax. The bill passed the California legislature July 17 and was approved by the Governor, taking effect in 2018. "This bill would, on and after July 1, 2014, and before July 1, 2030, additionally exempt from those taxes qualified tangible personal property purchased for use by a qualified person to be used primarily in the generation or production, as defined, or storage and distribution, as defined, of electric power or purchased for use by a contractor for the qualified person, as specified. The bill, on and after January 1, 2018, and until July 1, 2030, would also exempt from those taxes special purpose buildings and foundations used for the generation or production or storage and distribution of electric power. The bill, on and after January 1, 2018, and until July 1, 2030, would expand the definition of qualified person to include, among others, a person primarily engaged in the business of electric power generation."