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UTILITY COSTS, RATES, AND REGULATORY INCENTIVES

Introduction

For the regulator and policymaker, the principal intersection of DER with regulated utilities is ratemaking – both revenue setting and rate design. Together, the level and design of rates have been the regulator's central concern, and she has been guided by sometimes competing objectives: equity, economic efficiency, stability, and simplicity, among others.[47] The rates that end-users pay for grid-supplied electricity largely drive DER economics, and utility receptivity toward DER depends partly on how utilities are compensated for that electricity.

For utilities, the location of DER relative to the customer's meter is critical. Located on the customer side of the meter, DER raises concerns about lost revenue, control, and consistency of load profile. On the utility side of the meter, it raises none of these concerns, motivating regulators, utilities and other stakeholders to consider what role the utility should play on its own side of the meter. However, most DER installations to date are on the customer side, so the following discussion of rate and regulatory structures focuses on that more problematic situation.

For customers locating DER on their side of the meter, a major benefit is often the prospect of reducing their bill from their utility. For the utility, however, customer bill reductions can directly reduce utility earnings, to the extent that lower revenues are not offset by equivalent cost savings. Economic theory counsels that a profit-maximizing firm in a perfectly competitive market should set prices equal to the marginal cost of production: in that case any change in demand, and thus revenues, would be perfectly matched by a change in costs. For example, if demand declined, the resulting revenue reduction would be offset by an equal cost reduction, there would be no net revenue loss, and neither customer nor utility would be financially harmed. However, applying this principle to the pricing of monopoly electric services can prove controversial and challenging, given the capital intensity and long-term nature of such investment.

The difficulty revolves around the question of cost causation. Economists would argue that in terms of economic efficiency objectives, the best rate designs present price signals to customers that mimic the costs that utilities actually incur. This means that designing efficient rates and appropriate utility pricing structures requires an understanding of utility costs. Table __ in the next section identifies relevant categories of utility costs and their key drivers, and indicates which of these costs DER may be able to reduce, under what circumstances. The discussion following the table then addresses rate design and complementary rate-setting policies that can be used to better align utility costs and customer bills – i.e., to help ensure that customer bills

[47] See Bonbright, James C., *The Principles of Public Utility Rates*, Columbia University Press (New York: 1961).

reasonably reflect changes in utility costs, so that utility and customer interests move in the same direction.

However, customer bills alone do not capture all of DER's positive or negative impacts. There are also non-monetized benefits and costs, such as reduced central station or increased local air emissions; and impacts that extend beyond the individual customer, such as reduced spot market prices. The third section considers how these kinds of impacts can be recognized in evaluating and encouraging DER.

Finally, this chapter will touch on higher-level regulatory changes that could replace utility incentives to resist DER, with incentives to encourage it where it adds value. The discussion will suggest a pragmatic context in which to view DER's potential impact on customers today, and will close with a brief look at alternative arrangements that can help correct for historical biases and oversights and help implement DER opportunities that benefit multiple stakeholders.

Utility Cost Drivers and Rate Design Approaches

In order to evaluate rate designs that would better align customer and utility costs, it is important to understand how utilities incur costs. The table below lists the major components of utility costs, and the conditions under which DER may be able to reduce those costs.

Table __. Utility Costs and DER Impacts

Cost Category	Description of Cost and How It Is Incurred	Can DER reduce the cost?	Explanation
Connection Equipment	Cost to connect new customers and upgrade facilities for existing customers. Connection equipment is generally dedicated to specific customers with little sharing of facilities. Facilities are sized to an estimate of a customer's likely maximum load.	Yes, in some cases	Probably only – • where new customers installing DER require no (or limited) utility back-up for DER outages, or • where the customer load is about to grow (i.e. adding manufacturing capacity) and would require connection upgrades that onsite DER could avoid.
Distribution circuit and protection scheme	Costs incurred to serve the collective load of numerous customers. A combination of – • minimum costs needed to connect customers of any load size, and • additional costs needed to serve the coincident peak of connected customers These costs are primarily capital and non-variable in the short run (e.g., poles, wires).	Yes	Location-specific cost savings are possible where DER will avoid or defer upgrades to existing infrastructure, or permit installation of lower-cost, smaller facilities. At the same time, utilities sometimes point to cost increases from having to reconfigure protection schemes to ensure safe operation of a distribution system not designed to have power sources on or near customer sites.

Cost Category	Description of Cost and How It Is Incurred	Can DER reduce the cost?	Explanation
Distribution substations	Substations are located and built to minimize the total cost of circuits and substations, reduce losses and provide reliability. The need for substations is driven by – • the location of customer growth relative to existing circuits and substations, • the amount of surplus transformer bank capacity at existing substations, and • the number of positions for new feeders at existing substations.	Yes	At *existing* substations, the need to add new banks and feeders offers opportunities for cost-effective DER applications, *if* the annual load reduction DER provides is small relative to the capacity that a new transformer bank and feeder would add. The need for *new* substations in established areas also offers DER opportunities. This is less true in greenfield areas, because of the need to install infrastructure to connect new customers, independent of their peak loads.
Transmission circuit and substations	Similar to distribution circuits and substations. These costs generally are driven by peak customer loads and generation sources. Investment drivers can be complex because of network power flows, and probabilistic planning techniques often used to assess transmission reliability.	Yes	DER can have value in deferring transmission upgrades. Upgrade costs are often high, and the number of hours when DER would be required to reduce loads are often low. Transmission projects typically have longer lead times because of required regulatory and public review, so there is more time to implement DER and effectively defer the upgrade. Conversely, transmission projects often require larger capacity additions than DER, even in aggregate, can supply, or can cause loop flows that diminish DER's capacity value, depending on its location.
Generation capacity and energy	Utilities incur costs for each kWh that customers consume. These costs can be – • an internal cost of fuel, variable O&M, and asset depreciation (for utility generation), or • the market cost of electricity (for purchased generation). Utilities may also incur costs for – • contracts that ensure that capacity is available at peak times, or • construction and maintenance of low-efficiency plants that only run to meet peak demand or emergencies.	Yes	DER operation normally reduces customer energy costs for each kWh generated onsite. To the extent that DER in aggregate operates during the utility's system peak hours, it can also reduce a utility's reserve requirements, or its contract costs for reserve capacity. In certain types of energy markets, strategically placed and operated DER may help reduce market clearing prices, which can benefit all customers in the market.
Billing and metering services	Costs to administer customer billing.	Probably not	DER is unlikely to yield billing or metering cost savings, and could actually increase those costs slightly, due to more complicated billing and metering sometimes required of DER customers.
Routine and preventive maintenance	Costs of preventive and corrective maintenance of facilities. Generally independent of peak loading, unless facilities are degraded through operation beyond recommended levels. Mostly a function of facility age, level of deterioration, and timing (for activities performed at set intervals).	Yes, in some cases	DER's positive contribution is probably limited to reducing the number of new facilities that would need to be maintained, and sometimes reducing variable O&M costs for T&D (generally low anyway). In some cases, deferring new facilities prevents retirement of older, deteriorating ones with high maintenance costs, in which case DER could impose a cost penalty.

Cost Category	Description of Cost and How It Is Incurred	Can DER reduce the cost?	Explanation
Emergency response	Costs to respond to equipment failures. Often related to natural events such as storms, as well as unexpected equipment failures.	No.	Little opportunity for DER cost savings now, although DER role in restoration deserves attention.
Aging asset replacement	Costs to replace deteriorating facilities. Typically unrelated to peak loading levels.	No	Little opportunity for DER cost savings.
Reliability improvement	Costs typically involve installing facilities to lessen the impact or duration of outage events. May include looped distribution circuits to provide a secondary power source in the event of equipment failure, or installing fuses and switches to isolate and minimize faults	Possibly, but not under current utility rules.	Little opportunity for cost savings beyond DER's capacity-related values already included above. 'No-islanding' rules, and utility requirements to disconnect DER from the system at the 'first sign of trouble' preclude DER from materially affecting – or improving – reliability for other customers, although its presence may help forestall reliability problems to begin with.

The preceding table illustrates that DER can reduce costs for a *subset* of the total costs that a utility must recover from its customers. Rates are designed to recover the *total* costs plus a reasonable return on utility investment, so customer bill reductions not tied to the subset of costs actually reduced can often exceed the true savings available to the utility. This is especially true for "wires-only" utilities that capture no savings from reduced generation capacity and energy. Because there is no necessary relation between bill reductions and cost savings, and mismatches can occur, many utilities have been averse or at least disinclined to promote DER. The rate structures below discuss alternatives to align utility costs and customer bill savings, and thus remove some disincentives for utility DER support.

Volumetric (Energy), Fixed, and Demand Charges

Volumetric (Energy) Charge

Historically, utilities have charged for electricity primarily on a volumetric basis – i.e., per kWh of energy used. This remains the case for lower-usage customers, for whom demand meters are not cost-effective (i.e., do not elicit changes in customer behavior that save enough to justify the meter investment). Volumetric pricing also has the virtue of simplicity, for both the utility and the customer. Moreover, when utility costs were dominated by generation and utilities were enjoying strong growth and economies of scale, such pricing enabled them to cover their revenue needs and consistently make profits.

Today, however, energy charges are losing their appeal to many utilities, as they distance themselves from generation development and become 'wires only' transmission and distribution companies. This is so because energy usage no longer accurately reflects the way that utilities (especially wires-only utilities) incur many of their costs, and because energy charges afford utilities the least revenue stability among common rate design alternatives.

Fixed Charges

In the short run, most costs incurred by wires companies are fixed – i.e., they do not vary with customer usage levels. For this reason, some utilities argue that their rates should be comprised predominantly of fixed charges. In the extreme, this would call for fixed recurring charges for delivery service, the same for everyone regardless of the amount of energy taken, differentiated only by customer class, voltage levels, and perhaps some measure of customer size such as annual peak usage.

Demand Charges

The third common rate form is a charge based on the customer's peak demand. This 'demand charge' focuses on the customer's maximum usage over some short period of time (e.g., 5, 15, 30, or 60 minutes) during the billing cycle. Thus a customer that uses 1 kW of electricity for one hour of the month, would have the same demand charge as a customer that uses 1kW for 720 hours of the month.

Utilities assert that for some parts of their T&D system, the cost to serve customers is driven solely by that peak kW of usage, so that these two very different customers should receive similar bills. Peak demand generally varies less than energy usage, so demand charges yield greater revenue stability for the utility than 'per kWh' charges.2 Unlike the fixed charge discussed above, the demand charge does not depend on costs being invariate, but rather on the premise that costs are driven by peak demand instead of total energy usage.

By ensuring utility cost recovery independent of customer energy usage, rate designs with high fixed and/or demand charges remove the financial incentive for some utilities to oppose DER. However, they undermine the customer's ability to capture large economic benefits from DER, forcing DER to be "super" cost-effective in order to be deployed.

Short-run versus Long-run Pricing

The argument for large fixed-cost rate components is predicated on the fact that many utility costs (especially for wires-only utilities) are invariant in the short run. In most instances and on average, the marginal costs of energy delivery are very low, almost zero, in the short run. Many of those same costs, however, can be variable in the long run, so high fixed-price signals can hamper efficient long-run resource decisions. This is the problem of reconciling short-term and long-term cost impacts, and many regulators have elected to base rates on long-run marginal costs.48

In setting fixed charges, care should be taken to recognize that some costs that are fixed in the short run are variable in the long run. One option to address this is to base fixed charges on long-run costs, and to use alternative methods of setting revenues and allocating risks to address concerns about utility revenue collection and stability. These methods, described below, can give

[48] See Bonbright at 317-336 (Chapter XVII) and Kahn, Alfred, *The Economics of Regulation: Principles and Institutions*, Vol. I, John Wiley and Sons (New York:1970), pp. 83-86.

the utilities strong profit incentives to maximize both their own efficiency, and that of their customers.

Demand Subscription and Non-firm Standby

Both demand subscription and non-firm services offer alternatives to conventional standby charges that often discourage DER development. Standby charges are designed to protect utilities and non-participants from the negative financial impacts that self-generation customers can impose on them (through reduced payments not offset by other loads). The larger the generator, the more any outage will drive peak demand on utility facilities, and the more valid the standby charge. For small generators, however, the arguments for special standby charges lose force because the variations that small generators can cause for the T&D system may be well within normal operating variations that utilities plan for and have always accommodated.

Conventional standby rates typically assume that the utility retains its obligation to supply the customer's load when the customer's onsite generation is down for maintenance or unscheduled outages. Demand subscription and non-firm rates do not assume that – i.e., they do not assume that the utility must stand ready to provide back-up for all DER outages, but rather that customers can chose the level of standby they need for their operations.

For DER customers that do not require firm service, or that do not value it sufficiently to pay high standby charges needed to support utility facilities that would supply it, demand subscription offers a way to pay only for the capacity they need and value, accepting some level of risk in return for reduced costs.

For other DER customers small enough that their back-up requirements would not drive T&D peaks in any case, non-firm service offers the option to obtain back-up service for most times of the year, exposing them to curtailment risk only during utility peak demand periods.49

Both alternatives to conventional standby rates also expand the choices DER customers have to meet their individual reliability and security needs, without imposing the costs of these choices on utility shareholders or other ratepayers.

TWO-PART RATES

As used here, the two-part rate does not refer to the traditional distinction between energy (kWh) and demand (kW) charges. It refers instead to an innovative structure that protects utility revenues while providing price signals to customers to help control utility costs. It does this through a 'first part' rate that collects the customer's historical billing, coupled with a 'second part' rate that charges for increased usage, or credits reduced usage, at the utility's marginal cost

[49] Alternatively, it may be worth exploring separate rate classes for DER customers, and for customers participating in emergency demand response programs. These customers typically have distinctly different load profiles than other customers. Assigning them to distinct classes could smooth out any disturbances caused by individual onsite resource failures, and developing a standby rate based on the class contribution to utility costs would be consistent with conventional rate design approaches.

– i.e., the cost of expanded facilities avoided or deferred through customer DER initiatives. This type of rate levels the playing field for customers that increase or decrease loads (unlike standby rates, which some view as punishing reduced consumption).[50]

An issue for each of the rate options just outlined is that the very thing that makes them attractive to utilities – smaller bill reductions for consumption reductions – makes them less attractive to customers and conservation advocates, who typically favor the strongest possible price signals to enable and encourage reduced usage. If DER benefits are large enough, these types of rate innovations can help customer-side DER into the marketplace without prejudicing utility shareholders or non-participating customers. However, the modeling tool developed in the course of this work suggests that, at least using current California rate assumptions and today's technology costs and benefits, most DER will require more leverage to significantly penetrate electricity markets. The following incentive methods can provide that leverage by explicitly recognizing additional DER value where it exists.

RECOGNIZING ADDITIONAL DER BENEFITS

UTILITY DER PLANNING AND AREA-SPECIFIC T&D CAPACITY CREDITS

One frequently cited source of additional DER benefits is the potential to defer or avoid costs the utility would otherwise incur to upgrade T&D capacity. Published papers [51] on this topic indicate that the economic value can be substantial in some cases but is highly area-specific, and that in many distribution planning areas DER offers little or no deferral value at a given moment in time. Moreover, typical utility planning processes rarely identify, publicize, or offer benefit-sharing mechanisms to induce customers or DER providers to locate projects in high-value areas.

In order to determine where DER can provide locational benefits, wires company and ISO planners must be looking for these benefits and considering DER as a potential solution. Utility planning efforts do focus on targeting system weaknesses, but do not typically consider DER as a potential solution to the problem. Rather, most planning processes identify conventional wires solutions and set out to implement them without identifying or evaluating DER alternatives. By altering the planning process to identify where DER can solve grid problems, utilities can identify investments that benefit the DER host, the utility and its customers.

Some jurisdictions have begun to address these shortcomings. As discussed in Chapter __, California now requires utilities to consider DER as an alternative to distribution upgrades, and

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[50] Georgia Power Company has had particular success with this rate design for more than 1,600 of its largest customers under a real-time pricing tariff. See O'Sheasy, Michael T., "How to Buy Low and Sell High," *The Electricity Journal*, January/February 1998, Vol. 11, No. 1. For additional analysis, see [E3 publications ?]

[51] Cites??

to take steps to procure it where it appears to offer a least-cost solution. New York requires its utilities to evaluate DER for T&D projects whose costs exceed certain benchmarks, and is engaged in a pilot program that requires utility RFPs to procure DER where it can defer or displace needed T&D capacity.

Costs that utilities incur for prudent DER procurement, including any incentives needed to ensure its development in high-value areas or within critical time frames, can be funded from utility transmission or distribution budgets, and can be capitalized to permit utilities to earn a return of and on such funds comparable to traditional plant investments, keeping utility shareholders whole.

MONETIZING AND INCORPORATING EXTERNALITY COSTS INTO CHARGES OR CREDITS

Some emissions costs are monetized through markets for tradable emissions rights, or by internalizing the costs of pollution control technology. However, the literature suggests that these often understate the total costs that emissions (including residual emissions) impose on society. If these costs were fully monetized, certain clean DER technologies could merit significant benefits. These benefits can be paid for out of a general 'public goods' or 'system benefit' surcharge levied on all utility sales.[52] Under this approach, utility shareholders as such are not harmed because the funds are already earmarked for programs to enhance the public interest and funded through the dedicated rate component; utility earnings are unaffected by the amount of benefit payments.

RECOGNIZING THE 'GENERATION MULTIPLIER' EFFECT

For utilities that participate in single-price markets, targeted demand reductions can lower market clearing prices. Lower clearing prices confer benefits far beyond the individual customer or provider that reduced its demand. A 'generation multiplier' recognizes this wider benefit, and can allocate some portion of it as an incentive to parties to relieve system demand through efficiency measures and/or DER. Research on this topic has led to the adoption of a factor of four multiplier for summer on-peak energy reductions in California.[53] That means that each summer on-peak kWh reduction is credited with a cost reduction of four times the actual summer on-peak marker price. The additional three-fold value reflects lower generation prices passed along to all customers through the reduced market clearing price effected by that kWh reduction.

[52] The California Energy Commission's renewable energy rebate program described in Chapter __ is one example of such an approach.

[53] Cite??

Like the environmental externality funding described above, payments recognizing this generation multiplier effect can reasonably be funded through a public goods surcharge.

REALIZING SOCIETAL VALUES OF DER THROUGH EFFICIENT MARKET RULES

Regional energy, capacity and ancillary service market rules are being upgraded throughout the U.S. to make trading of these commodities more efficient. These rules can be designed to account for the valuable attributes that DER can offer under specifiable conditions. Assuring that a day-ahead bidding system can accommodate customer resources is one way to move toward this objective. Assuring that DER attributes that yield these values can actually receive credit for them is another way. A transparent market, where customers can readily be compensated for the value their DER resources provide to the system or society, would help customers make decisions to invest in those resources.

Higher-Level Regulatory Changes

In the New York proceedings and elsewhere (as in earlier efforts to increase demand-side efficiency), parties have suggested decoupling utility margin from kWh sales to help remove the perceived disincentive for utilities to encourage, or at least accommodate DER. Decoupling can occur in two primary ways. The first is to make the revenues that the utility receives from its customers more fixed, and less variable with changes in customer usage.[54] The second approach is to adopt a revenue-based performance ratemaking (PBR) mechanism. Revenue-based PBR would substitute for traditional cost-of- service ratemaking an approach that sets utility rates to recover a predetermined level of revenues (usually with some allowance for customer growth). This form of PBR removes the utility incentive to promote sales, and rewards utility shareholders if the utility reduces its costs – even if that means reduced sales.

While some favor the first approach, for reasons discussed earlier it is not likely to facilitate DER implementation. Moreover, the impact of high fixed charges on low-use and low-income customers limits regulatory acceptance of such a rate form. DER proponents, as well as conservation and efficiency advocates and customers, more often favor the second approach because of its strong incentives for efficiency. It represents a significant change from traditional ratemaking, with implications for many aspects of utility operations beyond those related specifically to DER. Although well-designed PBR mechanisms could help level the playing field, many observers would acknowledge that a wholesale shift to PBR to encourage DER at this stage of its development could be the tail wagging the dog.

As indicated by Table __, Appendix A and the modeling tool presented here, DER today appears to offer significant win-win opportunities in specific but fairly limited situations. For this reason, even if promoting DER were to shift some costs to non-participants or shareholders, any near-term impact is likely to be small, and certainly manageable by regulators.

On the other hand, many argue that the potential value from near-term incentives could be large. They observe that DER is comparable in many ways to energy efficiency measures 20 years ago. At early stages of their development, programs that make sense for society as a whole may fail the utility cost test. Just as some efficiency measures that are commonplace today that might not have achieved the critical mass they needed to succeed without the early incentive programs, some DER technologies have the potential to support viable, cost-effective industries and to add real value to the electricity enterprise over time. In that sense, the cost to promote DER now can be considered the cost of an option for the future.

One market adjustment regulators can make is to dedicate a small percentage of utility revenues to address market barriers to DER, and promote their deployment where they add demonstrable value for multiple stakeholders or society at large. This can be done through utility-run efforts that resemble energy efficiency programs, state-run initiatives that have the advantage of consistency across multiple utility service areas, or statewide efforts out-sourced to a dedicated program manager.

[54] See e.g., rate designs proposed by Southern California Edison in Application No. 00-01-009, Ex. SCE-5, January 2000.

As described in Chapter __ another device is a portfolio standard, already made available through legislation in more than a dozen states. Such standards typically require utilities and other load-serving entities to include a defined percentage of qualifying energy in their offerings, assuring some minimum level of diversification into qualifying energy sources. Such sources usually include specified renewables, but can also include ultra-clean and/or highly efficient DER (as part of an existing portfolio category or as a separate category).

To the extent that DER offer societal values beyond the benefits that accrue directly to their owner/ operators, allocating some of these societal values as monetary benefits to resource providers requires a connection to the electricity market. DER should be able to participate in these markets, even if that means overcoming existing technical and administrative barriers. Whether capturing fair value for occasional excess customer generation, or for planned and bid responses to curtail load, mechanisms to engage with the market are essential for DER providers to share in any benefits they contribute to the system.

DER offers both existing and potential future benefits. Those benefits can be fully realized only if regulators and policymakers take an affirmative interest in making the changes needed to capture and allocate values not recognized by today's electricity market structures. Some of those changes could have impacts considerably beyond DER, so policymakers clearly need to weigh the potential benefits of wider DER deployment against the 'side effects' and implementation costs those changes would entail. At a minimum, however, they should consider adopting DER incentives that compensate for DER benefits that cannot be realized because of unintended regulatory barriers or market imperfections. The final chapter suggests a framework for developing collaborative approaches to these tasks.

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A FRAMEWORK FOR COLLABORATIVE DER PROGRAMS

1. Introduction

This chapter builds on the catalog of approaches, the DER cost/benefit descriptions and modeling tool, and the discussion of utility costs and rate designs. It presents a framework that willing groups of stakeholders can use to design *collaborative programs* that build on earlier approaches to DER market integration, and that pioneer new ones.

This chapter focuses on pilot programs, not as an end in themselves, but as a means to advance toward the overall goal of integrating DER seamlessly into the larger electricity enterprise. The premise is that well-designed pilots, using the information and tools presented here, and implemented in different utility service areas under different regulatory regimes, will yield better information on actual in-service DER costs and benefits for regulators, utilities, and customers. Pilots can be structured to encourage innovation and experimentation, and to deliver valuable feedback on the efficacy of alternative incentive approaches. They will result in the deployment and integration of DER that adds value for multiple stakeholders during the pilot period, and in some cases well beyond it. And they will systematically demonstrate cooperative rather than adversarial approaches to advance stakeholder interests, including the public interest in more flexible, more robust options for affordable, reliable, and secure energy.

Although the approach described here builds on approaches described in the catalog, it can take advantage of the DER cost/benefit and allocation methodology developed here to refine them and to develop new, more precisely targeted DER programs. The framework approach also differs from many previous efforts because it focuses on collaborative stakeholder actions to ensure legitimacy, acceptance and mutual benefit; it is explicitly designed to yield win-win outcomes that more traditional regulatory approaches often neglect.

'Collaborative' programs here means programs whose objectives, scope, incentive mechanisms, and other characteristics are developed through the voluntary, cooperative efforts of committed participants, working together toward mutually beneficial outcomes.55 Key participants include regulators, utilities, customers, ratepayer and environmental representatives, DER providers and others. These programs offer opportunities to try innovative incentive forms designed to better

[55] Once a program is designed through this kind of process, a state public utility commission or other regulatory agency may need to authorize jurisdictional utilities to implement it in order to achieve the energy, environmental, economic or other goals agreed to by stakeholders (as in Green Mountain Power's arrangement with Sugarbush Ski Resort, described in the catalog). This discussion focuses on the collaborative process and potential program elements, rather than on any formal approval process that may be required once stakeholders agree on a program.

align stakeholder interests, and to provide comfort to regulators that a 'win' for some need not be a loss for others whose interests they safeguard.

DER stakeholders' underlying interests are often more compatible than the positions they advocate in formal regulatory proceedings – positions that often proceed from incomplete understanding of other parties' needs, desires and business constraints. Regulatory litigation typically is not designed to produce consensus or compromise, but to yield a decision that parties can act on (or challenge, as the case may be). This framework, on the other hand, is intended to help structure non-adversarial exchange of ideas and constructive cooperation among stakeholders to find solutions that benefit as many as possible, as much as possible, with as little prejudice to others as possible.

Programs designed through this process will be 'pilots' in the sense that they pioneer innovative strategies to integrate DER into existing electricity markets, and test new approaches to help stakeholders learn what works best. Pilots may be limited in time and scope to encourage participation, and to allay stakeholder concerns about previously untested approaches. But stakeholders may also choose to pursue longer-term programs that yield significant, measurable results for a utility system or planning area, and/or for participating customers or customer classes.

Depending on the utility system and its customers, this could mean programs providing anywhere from a few megawatts to a few thousand, or involving some minimum number of customers, or some threshold level of demand reduction or curtailment. Pilot programs can include multiple individual DER installations employing diverse technologies. Installations may remain in place and continue to provide benefits long after the formal pilot program ends. By developing solid experience with various forms of DER incentive approaches under real-world conditions, these programs should also serve as thoughtful models that other jurisdictions can cost-effectively replicate, adapt to local conditions, and improve over time. In other words: the approach described here can not only facilitate collaboration on limited pilot programs, but can provide a solid foundation for more wide-ranging DER market integration efforts.

Each pilot program is expected to develop its own specific objectives through the stakeholder collaboration process. In general, however, these programs can be much more than DER technology demonstrations. They can also demonstrate:

- more constructive ways for DER participants to communicate and cooperate
- new ways to optimize benefits for multiple stakeholders
- creative rate design and other regulatory incentives targeted specifically to encourage DER that adds value beyond conventional electricity supply
- innovative departures from 'business as usual' in the DER marketplace

The framework described below is organized in four parts. Section 2 deals briefly with structuring the collaborative process and defining the program's scope and objectives. Section 3 introduces three basic strategies that participants may want to consider in their programs, and presents tables suggesting the kinds of stakeholder needs that each strategy can address. Section 4 outlines some options available to tailor each of the basic strategies to local needs. Finally, Section 5 presents a detailed example showing how the process outlined here, the catalog and rate discussion presented earlier, and the cost/benefit modeling tool can be combined to evaluate a potential CHP pilot project or program.

2. Structuring the Collaborative Process

How does a group of interested stakeholders collaborate to create real-world DER pilot programs that benefit multiple stakeholders? The following outlines important questions to address and steps that can be taken toward this end.

A. Which stakeholders should participate?

The E2I team can work with state, regional and local interests to identify an initial group of DER stakeholders open to pursuing a collaborative pilot program (CPP). Unlike formal regulatory proceedings involving tens or scores of parties who interact through formal adversarial hearings and written filings by counsel, collaborative efforts will be more productive with a small and manageable core group of entities and individuals, supported as needed by topical experts in their organizations. Participants will need to coordinate busy schedules for regular meetings; engage in in-depth discussions of complex issues; and maintain continuity over a period of weeks or months. Experience suggests that coordination, communication and continuity are difficult to maintain with a large core group (e.g., more than ten or twelve regular participants), although others certainly can offer specialized support as needed.

The initiating members will need to decide on the minimum set of stakeholders needed to move the CPP process forward. These will almost certainly include a local utility with something to gain from encouraging DER in the region covered by the CPP. They will likely include a state utility commission and/or other state energy agency, since many of the initiatives discussed here will ultimately benefit from (if not require) regulatory support. And they will need the perspectives of DER providers (e.g., equipment vendors or project developers), and of prospective DER customers (including individual customers and/or interested trade associations). Depending on how these key interest groups view the objectives of the CPP, they may identify other stakeholders whose input will be essential to move the program forward.

Once there is agreement on the list of essential participants, each entity will need to designate one or more individuals as its principal representative(s) in the collaboration. The key to success will be the commitment and ability of each participating entity – and of each individual representative – to work collaboratively and flexibly with other stakeholders to develop mutually beneficial approaches, and to put aside the adversarial relationships that typically characterize formal regulatory proceedings. Old habits die hard, so an organization's most forceful regulatory advocates may not be its most constructive collaborators.

B. What are the collaborative's structure and ground rules?

The first order of business for this core group will be to decide how the collaborative will function – how it will govern itself, and how it will make decisions. Will it elect a 'neutral' leader or coordinator, or will a stakeholder representative serve that function? Will it need to establish working groups? Will decisions be made by consensus, majority vote, or something else? Answers to some of these questions may emerge as the group sorts out its objectives and priorities, discussed below.

A critical early step is to create a safe environment for exchanging ideas and discussing what may be sensitive business information to some participants. For example, it may be important to agree that what is said during collaborative discussions will not be introduced as evidence in any commission proceeding or other formal venue. Participants may also want to agree to treat collaborative discussions as confidential within the group and by the principals represented, and not to disclose them to the public or the press without the group's consent. Or they may want to acknowledge explicitly that proposals or agreements reached within the group will be subject to good faith approval by their principals. In some cases, participants may want to look to formal settlement rules adopted by the utility commission or other state agencies for guidance, whether or not they would technically apply to the collaborative's activities.

C. What are the collaborative's objectives and priorities?

Participants will need to clearly identify the needs that their effort can serve – i.e., what can a collaborative approach accomplish that the state's ongoing DER activities cannot, or have not?

Each stakeholder group will have its own interests in participating in the CPP. For example, a utility's overriding interest may be to address system constraints, retain customers, take advantage of regulatory incentives, evaluate new business opportunities, preserve existing ones, or something else. Customers' interests may be to control and stabilize energy costs, hedge risks, ensure supply, reliability and power quality, take advantage of regulatory and financial incentives, etc. Regulators may be especially interested in costs, resource adequacy, ratepayer protection, utility financial health, equitable allocation of costs and benefits, environmental issues, etc. Whatever motivates an entity's participation, its interests should be explicitly identified and brought forward to the group, since the overall objective will be to advance as many of them as possible, and to reconcile any that seem to be in opposition.

In identifying and prioritizing possible program goals and objectives, collaborative participants should try to understand how achieving their own priorities will impact other stakeholders, and how different stakeholder priorities will be reconciled to agree on a direction. Each jurisdiction's pilot design will depend on how collaborators answer the following kinds of questions:

- Will projects be designed primarily to benefit the grid? Will benefits to individual customers be incidental to the ultimate success of the collaborative?
- Conversely, should projects primarily benefit individual customers, with grid benefits incidental?
- Will the collaborative focus on projects that add specific value to the grid, or to DER customers, or will it require both?
- Is it enough to facilitate customer installations that benefit the DER customer and generally keep non-participants neutral or better, whether or not the project yields immediate and specific grid benefits?

Other goals for collaborative members to prioritize might include the following:

- eliminating specific, identified barrier(s) to DER penetration

- installing some minimum number of MW, or reducing demand by some minimum amount
- testing the impacts of innovative incentive mechanisms or rate designs on DER customers and non-participating ratepayers
- developing DER planning, procurement and contracting templates for use by others
- demonstrating the impact or usefulness of specific attributes claimed for DER – e.g., local capacity cost deferral, congestion relief, cost and pricing impacts, specific grid support functions (reactive power, etc.)
- demonstrating DER/grid interfaces, protocols, etc., or streamlining procedures to integrate DER with grid operations
- advancing and testing mutually agreeable tools to compare DER to grid solutions
- demonstrating DER environmental effects
- demonstrating cost-effectiveness of various DER approaches, technologies, etc.
- creating models for effective collaboration among DER stakeholders, and developing institutional mechanisms for sustainable relationships linking utilities, customers, regulators, DER providers and other stakeholders.
- producing results with widespread application, replicable by others

D. How will the collaborative measure results and evaluate success?

Based on the goals and objectives it chooses to pursue, the collaborative should decide upfront how it will measure results and evaluate program success. Will it measure success in terms of capital investment deferred, megawatts of DER installed, megawatt-hours of usage reduced, tons of NOX or CO2 emissions avoided, lack of prejudice to non-participating utility customers, replicability of results, or other criteria?

Once they decide on measurement and evaluation criteria, program participants should develop a program evaluation process. Such a process would periodically track the advancement of pilot projects, the usefulness of any incentives, progress in removing barriers, etc., to learn what works well and what doesn't under various circumstances, and to help refine future approaches.

E. How can the collaborative foster innovation and experimentation?

Since the intent of the CPP is to test new and untried concepts for market integration, participants might expect that some innovations will work well, and some may not. In order to provide freedom to experiment and yet protect stakeholders from unforeseen consequences, participants may want to restrict the size and/or duration of the pilots; constrain their application to certain customer classes; limit their precedential effect for future activities; or establish other boundaries that encourage flexibility but confine the risks of failure.

Once these considerations have been addressed, participating stakeholders can use the remaining sections of this framework to outline possible projects that will meet their defined objectives and advance their priorities, and project teams can begin to develop actual projects.

3. Basic Program Strategies

This section outlines three basic strategies that may offer a useful starting point for collaborative efforts by DER stakeholders to build on the best features of recent DER initiatives, and to shape new ones that better integrate DER into larger electricity markets. These strategies can help stakeholders structure programs that encourage and facilitate DER where it offers real, identifiable benefits, and that remove unnecessary barriers to deployment in those situations. The strategies can be viewed as generic categories around which to structure DER pilot programs. The next section will offer examples of more specific options available to tailor these strategies to local needs.

Program participants' interests vary widely, as do regional, state, and local markets, so individual programs may look quite different in California, for example, than they do in New York. State-specific pilots will recognize these differences, as well as differences in state law and regulation and in the kinds of economic, environmental or system problems that demand attention locally or regionally. Thus the generic strategies can help address identified stakeholder needs, and the options can suggest ways to implement these strategies that may be more or less appropriate under differing program conditions.

The programs that E2I envisions would not promote DER for its own sake, or subsidize DER projects into markets where they do not contribute to broader energy and environmental policy goals. Rather, these programs would aim to meet stakeholder needs for new arrangements that –

1. ***Leverage DER value*** by recognizing multiple value streams that today's markets may not;
2. ***Introduce efficient incentives*** to facilitate and deploy DER in those situations; and
3. ***Eliminate barriers*** to DER that inhibit innovation, but on balance serve little public purpose.

Leveraging DER value refers to approaches that capture and allocate among stakeholders multiple value streams that can flow from DER selected, sited, sized, and operated to create value for more than one group of stakeholders. These approaches might, for example, take the form of tariff terms applicable to broad customer classes, model provisions for use in bilateral or multi-party contracts, reallocation of interconnection charges depending on the project's value to the grid, etc.

Collaborative efforts to capture and allocate DER value streams will require some common understanding of what those value streams are, what they are worth, and what it means to allocate them among stakeholders in different ways. The cost/benefit and allocation modeling tool is intended to help collaborative participants see where and to what extent DER adds value or imposes costs beyond traditional approaches; to objectively assess impacts on different stakeholders; and to identify possible re-allocations or project configurations that could create benefits or reduce costs for other stakeholders. This analytical tool enables participants to tailor their assumptions and analysis until they are comfortable with its objectivity and accuracy, and to assess a variety of impacts easily and with some confidence in the results.

Introducing efficient incentives refers to initiatives that send price signals to utilities, end-users, and DER providers that better reflect the true costs and benefits of DER solutions in specific situations. Examples include area- and time-specific credits or other customer incentives, rebates and equipment buy-downs for preferred technologies, utility rate designs, etc..

Eliminating barriers here refers to eliminating or reducing obstacles to DER siting, installation, operation, and value recognition in the market. It includes minimizing transactions costs for all participants, from project inception to completion.

These three strategies overlap at times, and are not mutually exclusive. Collaborative programs that incorporate some or all of them should make it easier for utilities to signal where DER adds value to their systems. They should also help end-users adopt DER solutions that supplement and reinforce utility service, while serving their own interests and benefiting other stakeholders. Much of the thinking around DER issues regards end-users as passive recipients of energy and services. Utility service is overwhelmingly the default, and usually only large customers and projects can absorb the transactions costs of onsite energy projects. A more active approach to market integration (at least for customer-side DER) views end-users not just as utility customers, but as potential system contributors and problem-solvers when empowered to act in their own interests. This collaborative framework approach supports that view.

Pilot programs structured using this framework can be flexible and limited in scope and time, without necessarily committing to long-term, system-wide changes until experience demonstrates their soundness. This should facilitate negotiated solutions that streamline the process, for at least long enough to see which solutions offer real promise.

Tables __ - __ below illustrate how the three basic strategies relate to the needs of each key stakeholder group – utilities, DER providers, DER customers, and regulators representing societal interests – and where each strategy might be used to shape collaborative programs to meet those needs. The first column in each table focuses on the needs of a key stakeholder group that DER may be able to help meet. For each need identified, columns 2-4 describe barriers to its fulfillment; current approaches to overcoming those barriers; and new DER approaches that might be more successful. The last column in each table suggests one or more framework strategies that can address the particular need, lower the barriers to meeting it, and support new approaches that stakeholders can pursue cooperatively.

Since these strategies are general in nature, the text following the tables presents more specific options to tailor each of them to local needs – i.e., ways to leverage DER value, to efficiently incentivize action, and/or to eliminate remaining barriers. By systematically considering which strategies are relevant to meeting particular stakeholder needs and what specific options might be employed toward that end, the hope is that collaborative participants can devise initiatives that address not only the interests of individual stakeholder groups, but more importantly, the common or complementary interests of all groups. The intent is to help structure the collaborative process, and to guide it toward solutions that benefit multiple stakeholders without prejudicing others.

Table __. Utility Interests

NEED	BARRIERS to DER USE	CURRENT APPROACH	NEW APPROACH	RELEVANT PROGRAM STRATEGY
Cost-effective asset deployment	High DER capital cost	Utility pays for DER based on its assessment of the singular value to it of capital deferral or reliability	Share equipment costs according to value created	Leverage DER value
	High transaction costs due to safety/reliability and permitting issues, and sometimes to over-designed interconnect hardware	Develop uniform inter-connection standards and processes, simplified permitting procedures, and net metering for some resources	Where conditions warrant, allow more flexible processes for pilot, without precedential value for other projects	Eliminate barriers
Lead times that correspond to planning cycles, and projects that address specific system needs	Long lead times from concept to execution, and inflexible processes	Require utilities to issue standard RFP's for competitive bids	Allow utilities, customers & DER providers flexibility to negotiate special contracts within pre-defined limits	Leverage DER value
Obligation to supply energy for multiple users on demand	Customer preference to control generator or load curtailment is not consistent with utility reliability criteria	Mostly rely on voluntary models; California exempts customer from standby fees if it provides physical assurance that load will drop if DG fails	Utilities or aggre-gators control customer equipment when required to meet planning criteria, and pay customers for any added reliability they provide.	Leverage DER value
Multi-MW solutions suitable for utility-scale operations	Most DER are too small to meet utility needs by themselves	Few DER projects installed to meet utility needs	Aggregate DER devices with control and communication that allows central dispatch	Leverage DER value
Improved earnings margins or ROE	DER that displaces load reduces throughput and revenues tied to it	Utilities reduce DER value through high standby rates; limited use of performance-based incentives	Consider revenue-based PBR, 2-part rates, and other pilot approaches to test ways to promote least-cost societal solutions	Introduce efficient incentives

TABLE __. DER PROVIDER INTERESTS

NEED	BARRIERS to DER USE	CURRENT APPROACH	NEW APPROACH	RELEVANT PROGRAM STRATEGY
Reduce turnkey project costs	Cost of equipment	State financial incentives	Share equipment costs according to value created	Leverage DER value
	High transaction costs to install equipment due to long, costly and complex permitting and utility approval process	Develop uniform inter-connection standards and process, simplified permitting procedures, net metering for some resources, etc.	Where conditions warrant, allow more flexible processes for pilot, without precedential value for other projects	Eliminate barriers
Tap additional revenue streams to cover project costs, and increase design flexibility	Market rules restrict new entrants into wholesale market	Restrict efforts to selected RTO markets	Introduce wholesale DER sales into new markets on a pilot basis	Eliminate barriers
	Current peak power prices are low relative to off-peak prices	Wait for supply and demand to balance	Target pilot program to congested transmission areas	Leverage DER value
Tap additional revenue streams to cover project costs, and increase design flexibility	State laws preclude most retail sales, limiting development flexibility	Standard offers or case-by-case regulatory approval	Flexible bilateral or multiparty contracts	Leverage DER value Eliminate barriers

Table __. Regulatory and Societal Interests

NEED	BARRIERS to DER USE	CURRENT APPROACH	NEW APPROACH	RELEVANT PROGRAM STRATEGY
Mitigate wholesale price spikes and transmission congestion	DER have limited access to wholesale markets	Few DER are used to create value in bulk power markets	Design approaches to open wholesale markets to DER	Eliminate barriers
	High turnkey cost of DER solutions	View DER as competing with wholesale prices	Share equipment costs according to value created	Leverage DER value
Improve environmental quality	High cost of clean DER equipment	SBC subsidies	Design incentives and/or rate structures to reflect environmental benefits	Leverage DER value
	Market doesn't recognize value of environmental benefits			Introduce efficient incentives
Increase reliability of bulk power delivery	Small scale of most DER machines	Ignore bulk power benefits	Aggregation	Leverage DER value
	DER lacks access to ancillary markets		Design approaches to open ancillary markets to DER	Eliminate barriers
Add demand response component to market	Cost of meters and other technology that facilitates demand response	Some demand response programs tried, but success limited by wholesale market conditions	Value demand response that reduces generation at the margin based on its price mitigation effects	Introduce efficient incentives
	Restrictions of wholesale market rules	Market does not recognize overall effects of demand response		Eliminate barriers
Ensure fair cost allocation	High standby charges, exit fees, unavoidable fixed rate components	Weak pricing signals; rate averaging; inflexible standby charges; uncertain exit fee prospects; increased fixed rate components that leave fewer 'avoidable' costs	Use cost/benefit methodology presented here to identify win-win; use targeted rates and tailored incentives to meet pilot program goals.	Introduce efficient incentives

Table __. DER Customer Interests

NEED	BARRIERS to DER USE	CURRENT APPROACH	NEW APPROACH	RELEVANT PROGRAM STRATEGY
Increased reliability of on-site supply	Cost of clean generators	Each customer pays for its backup generator based on its assessment of the singular value of reliability to itself	Share equipment costs according to value created	Leverage DER value
Increased energy efficiency to reduce costs of operation	Bias against CHP Difficulty of evaluating in uncertain markets, and retrofit cost	CHP viewed mainly as an electric resource for site needs; little flexibility to size otherwise.	Recognize CHP and energy efficiency benefits to the system and other customers, beyond the CHP host site	Eliminate barriers Leverage DER value
Ability to manage energy usage to reduce costs	Cost of meters and communications technology to enable demand response	Some demand response programs tried, but success limited by wholesale market conditions	Value demand response that reduces generation at the margin based on its price mitigation effects	Leverage DER value
	Restrictions of wholesale market rules	Market does not recognize overall effects of demand response		Eliminate barriers
Ability to assess potential value of DER options	Uncertain market and regulatory conditions; unknown or unfamiliar analytical tools.	Shifting regulatory approaches and volatile energy markets; proprietary and little-known tools	Enhance certainty for a defined pilot period, under specified conditions; make available simple, objective screening tools.	Leverage DER value
Ability to import from or export to the grid where desirable for economics or flexibility	Long, costly, and complex permitting and utility approval process. Sometimes over-designed interconnect hardware	Develop uniform interconnection standards and process, simplified permitting procedures, net metering for some resources, etc.	Address grid safety and reliability concerns presented by specific program or project only; exempt DER pilot customers from regulatory jurisdiction if necessary.	Eliminate barriers
	High standby charges, exit fees, unavoidable fixed rate components,	Weak pricing signals; rate averaging; inflexible standby charges; uncertain exit fees; increased fixed rate components that leave fewer costs 'avoidable'; net metering for small renewables.	Use cost/benefit methodology presented here to identify win -wins; use targeted rates and tailored incentives to mee pilot program goals.	Introduce efficient incentives
	System limitations, utility resistance, state law constraints	Likely regulation for offsite sales.	View end-users as potential contributors and problem-solvers in wholesale and retail markets; exempt DER pilot customers from regulation if necessary.	Eliminate barriers
Ability to use on-site generators to hedge price risks of spot market contracts	Lack of retail access to wholesale markets	Limit customer use of on-site generators to providing back-up during utility outages	Customers in hourly pricing programs install generators in cooperation with their energy supplier; design pilots to monetize the hedging risk.	Eliminate barriers Leverage DER value

4. Options for Tailoring Basic Strategies to Local Needs

STRATEGY ONE: LEVERAGING DER VALUE

As indicated above, ***leveraging DER value*** refers to approaches that capture and allocate among stakeholders multiple DER value streams – i.e., value streams created when DER is selected, sited, sized and operated optimally, providing value to more than a single stakeholder. These approaches can be implemented through mechanisms such as tariffs that apply to broad customer classes, model contract provisions between parties to DER transactions, or rebate or credit programs.

As noted earlier, collaborative efforts to capture and allocate DER value streams require some common understanding of what they are, how they can be created, what they are worth, and who benefits or pays if they are re-allocated in various ways. The cost/benefit modeling tool enables collaborative participants to develop that understanding, by analyzing various DER technologies and applications under a range of conditions that affect each type of value stream, and comparing the results from different stakeholder perspectives. Participants may wish to modify parts of the analysis, and will need to tailor input assumptions (e.g., price forecasts, rate structures, technology characteristics, and incentives) to reflect local conditions. Once that is done, the tool can help determine which costs and benefits drive the outcome, and where they might be allocated creatively to support win-win programs.

The following list recaps potential sources of DER value. Most of these are illustrated in the catalog and/or accounted for in the modeling tool. Those not included in this version of the model but which could be incorporated in future versions are indicated in brackets:

1. *for DER Customers –*
   - electricity bill savings
   - savings from avoided fuel costs (with CHP)
   - sales of renewable energy credits (in some jurisdictions)
   - equipment buy downs and project rebates (in some jurisdictions)
   - other incentive payments (e.g., locational credits)
   - increased reliability and security of supply
   - [participation in hourly energy markets with a physical price hedge]
   - [participation in demand response programs] [56]

2. *for Utility Shareholders and/or Other Ratepayers –*
   - avoided or reduced wholesale energy purchase costs (from unpurchased energy, or peak price mitigation where transmission rights or congestion pricing are established)

[56] The model does not include hourly dispatch or demand response because these have not yet been widely implemented in California, whose pricing and rate structures are used as examples in the current version of the model. In other states where they have been implemented future versions of the model can incorporate them, although they do add complexity to the basic screening tool 'template' presented here. In any case, the current model does allow users to input a 'market multiplier' where the market design is such that generators operating during critical periods can actually reduce overall market prices for that period (e.g., in a transmission-constrained local area subject to an hourly marginal price clearing market, such as PJM).

- avoided or deferred generation capacity cost
- avoided or deferred transmission and/or distribution capacity cost
- [increased capacity factor for utility generation (assuming sufficient DER penetration)]
- [service to remote off-grid loads]
- [distribution engineering benefits (line loss reduction, voltage support, voltage regulation, reactive power support, equipment life extension, reduced facility maintenance, etc.)]

3. *for Society Generally* –
   - reduced emissions (where load management or low/no-emission DER offsets dirtier generation)
   - [increased network reliability from siting energy sources closer to loads] [57]

Even with all these potential value streams, DER have had limited success in penetrating U.S. electricity markets. An important reason is that many of these value streams, *taken alone*, cannot overcome the initial cost barriers of current technologies, or the transactions costs of deploying them in energy markets designed for large central station supply. A missing element needed to enable successful DER deployment and widespread market penetration – and a key challenge for collaborative members designing pilot programs – is the ability to capture *more than one DER value stream.*

Optional Approaches to Leverage DER Value

The following lists optional approaches that can improve overall economics by recognizing multiple DER values. Some of the individual options have been tried in some form (as described in the catalog), and some are being proposed for trial by E2I's project team. They include DER deployments where:

1. *Customers use on-site resources to create value in wholesale energy markets by* –
   a. running onsite generators to reduce load for demand response programs
   b. running onsite generators to hedge hourly pricing contracts
   c. curtailing load to participate in demand response programs

2. *Customers contribute to societal needs for efficiency and environmental improvement by* –
   a. installing energy efficiency improvements that reduce their costs while improving societal resource efficiency
   b. installing CHP systems that reduce their energy bills while improving societal resource efficiency
   c. installing clean energy systems that reduce their utility bills while enabling other generators to reduce pollutant emissions

57 Network reliability improvements, like distribution engineering benefits, are difficult to quantify, both in terms of how much reliability may improve and how much any improvement is worth to society. The current version of the model does not include any reliability value beyond the avoided cost of system upgrades to meet prevailing reliability standards.

3. *<u>Distribution utilities reduce their costs to upgrade or expand the grid to meet growing demand by</u>* –
   a. using customer resources (efficiency improvements, CHP, clean baseload generation, etc.) to reduce energy use
   b. using customer demand response resources (air conditioner controls, backup generation, operating limitations, etc.), to limit peak demand

4. *<u>Utilities install DER to address multiple needs (i.e. wholesale price mitigation, transmission congestion mitigation, and grid reliability)</u>*

STRATEGY TWO: INTRODUCING EFFICIENT INCENTIVES

Again, ***introducing efficient incentives*** refers to initiatives that send price signals to utilities, end-users, and DER providers that better reflect the true costs and benefits of DER solutions in particular situations. Examples include customer credits, rebates, equipment buy-downs, and utility rate designs.

<u>Optional Approaches to Introduce Efficient Incentives</u>

The following lists sample approaches to providing incentives that reflect the value of DER solutions, to encourage *customers and DER providers to install* and *utilities to facilitate* DER:

<u>Incentives to Customers and DER Providers to Install DER</u>

1. Utility tariffs that pay customers fixed amounts for load reduction, including reductions –
   a. delivered over a period of time (kWh/yr.), or
   b. delivered at the utility's request ($/kW/mo. or $/kW/event)

   Customers may need to meet siting and reliability criteria, or reduce load in specific planning areas.

2. Bilateral contracts between utilities (or DER aggregators) and customers with onsite generation, whereby the utility (or aggregator) –
   a. may dispatch the generator whenever it is not needed to respond to an outage; and
   b. pays for generator maintenance, interconnection upgrades, fuel expenses, and/or a percentage of any wholesale revenues.

3. Utility discounts on electricity charges to customers who commit to use DER to reduce the utility's cost to serve load on a substation or circuit (e.g., by deferring upgrade investments).

4. Utility waivers or discounts on standby fees to customers who physically assure that their loads –
   a. will not exceed agreed limits at any time, or at certain times; or
   b. will drop off the utility's system if their onsite generation fails.

The provides the most value where the utility centrally controls the load-limiting device, and only when the customer load will cause the utility's circuit or substation to exceed design limits.

5. Utility or third party (e.g., an emissions trading entity) rewards DER owners for environmental attributes provided by clean DER systems at customer sites.

   Values may be driven by portfolio standards that mandate renewables purchases, and recognized through either payments or credits. Onsite generation may represent a small share of these markets, which are typically driven by large wind turbine installations.

6. Utility or RTO payments or credits to customers who agree to limit usage on request, or when pool prices exceed a specified threshold.

7. Utility discounts on gas rates to customers with high-efficiency, high load factor onsite generation (e.g., true cogeneration or high-temperature fuel cells).

8. 'Public goods' or 'system benefit' charges collected from utility customers under some restructuring schemes, and paid to those who install clean and/or high-efficiency DER.

9. Hourly pricing contracts with energy suppliers that enable DER customers to benefit from low spot market prices, yet operate their own generators during high price periods as a physical hedge against price volatility.

10. ISO or RTO contracts with customers to pay for ancillary services they deliver to wholesale markets.

11. Federal and state government RD&D and economic development programs, private research and trade organizations, or others pay or rebate all or part of the costs of customer DER installations.

Incentives to Utilities to Facilitate DER

1. Regulatory assurance that utilities will recover –
   a. costs prudently incurred to administer DER acquisition programs; and/or
   b. part or all of any extraordinary revenue loss that demonstrably results from energy efficiency or other DER programs that utilities are required to facilitate; and/or
   c. usage-based charges equivalent to fixed charges traditionally approved for system investments whose long-term marginal cost is greater than zero.

2. Regulatory authorization for utilities to –
   a. provide customers with advanced communication devices and real-time price signals that enable them to schedule their energy usage during the utility's low-cost periods
   b. automatically cycle customer equipment (e.g., air conditioners, pool pumps, and other non-critical loads) during the utility's high-cost periods.

Prices can be offered are in several blocks, some lower than otherwise applicable tariffs. By scheduling loads to maximize usage in low-cost periods, customers can reduce their overall bills.

3. A higher authorized return on equity for –
   a. utility investment in specified DER programs (e.g., cost-effective solar, energy efficiency or demand response, high-efficiency fuel cells); and/or
   b. achieving pre-defined efficiency or cost goals.

   Such incentives can also take the form of penalties for non-performance or failure to meet goals.

4. Decoupling some portion of utility profits from capital investment and utility revenues from kWh throughput, and basing utility profitability on efficient asset use, effective cost control, increased reliability, and customer satisfaction.

STRATEGY THREE: ELIMINATING BARRIERS

Eliminating barriers here refers to eliminating or reducing obstacles to DER siting, installation, operation, and value recognition in the market. It includes minimizing transactions costs for all participants from project inception to completion.

For DER pilots (and wider DER deployment) to succeed, at least three types of barriers may need to be addressed. The first is *permitting and interconnection* issues that delay and add (sometimes unnecessary) costs to projects. The second are *market structure* barriers, such as those that preclude DER from participating in wholesale markets (because load-side resources historically have been considered different from large generating resources). The third are *transactional* barriers: DER projects are often site- or situation-specific, so the parties need flexibility to negotiate and structure agreements tailored to individual situations, while keeping transactions costs reasonable for small projects. To achieve this may require overcoming both legal and cultural obstacles.

The following suggests some sample approaches for addressing each type of barrier. Pilot participants can consider these as starting points, but will need to identify and address barriers specific to their particular locales, markets and regulatory regimes.

Addressing Permitting And Interconnection Barriers

Emissions Permits:

1. To reduce the high cost of permitting each individual generating unit, enable permitting agencies to *pre-qualify classes* of clean generating units and establish *blanket exemptions* for those (as California is doing).

2. To reflect that environmental impacts depend partly on the duty cycles of DER equipment, develop a special permitting process for emergency generators that would focus on their *annual, rather than instantaneous*, emissions profile (as New York has done for generators including those used in the NY ISO Demand Response Program).

3. To recognize efficiency benefits, establish a special category of permitting for CHP applications that would focuses on total *net* emissions, taking into account, for example, boiler emissions offset by the CHP installation.

Land Use Permits:

To reduce the time and expense of obtaining zoning permits for DER facilities, establish *local exemptions or expedited review* for generating equipment that meets pre-established standards. Certain California municipalities have expedited renewable energy installations as a way to avoid a proposed utility transmission line through their areas – permitting a solar project, for example, in only three days, an unprecedented fast-track for a zoning permit.

Building Permits:

Building permits are sometimes delayed because inspectors are unfamiliar with DER equipment, and costs increase because multiple permits are required for jobs that cross normal trade boundaries. Building, plumbing, electrical, fire, and other inspectors often oversee even relatively small DER projects. Local and state training to familiarize building and code inspectors with DER equipment and connections is one approach to reduce these delays and costs.

Utility Interconnection:

States and utilities increasingly are adopting model standards to simplify the interconnection process for smaller resources. This is necessary but not sufficient to make projects happen quickly. Pilot programs could –

1. Designate technical contact people in each participating organization (DER provider, customer, utility) whose specific responsibility is to expedite action as issues arise.

2. Encourage innovation by reducing concerns that a solution appropriate for the immediate situation might tie the parties' hands in future cases with different circumstances, by adopting a 'super-expedited' process explicitly focusing only on grid safety and reliability

concerns presented by the specific program or project, and expressly recognizing that any solution adopted need not set a precedent for future projects.

3. Cooperatively address insurance and indemnification requirements in interconnection agreements in advance to ensure that they are fair and reasonable, and will not present surprise obstacles as projects proceed.

<u>Addressing Market Barriers</u>

To afford DER developers and customers added flexibility and incentive to design win-win projects –

1. Work with ISOs and RTOs to allow DER sales into wholesale markets; to ensure transparent wholesale price signals; and to encourage DER that can mitigate transmission congestion.

2. Where time-of-use retail rates that reflect time-varying costs and benefits are not available, or not adequately differentiated by time or location, introduce or refine them to signal customers and DER providers where and when DER can provide value to the system.

3. For DER projects involving offsite transactions that might otherwise trigger state commission jurisdiction under traditional legal definitions, establish exemptions up to some agreed limit for certain types or numbers of projects needed to test promising DER approaches or configurations.

<u>Addressing Transactional Barriers</u>

Transactional barriers take many forms, but DER stakeholders most often complain about utilities' perceived lack of flexibility to enter into agreements tailored to individual customer and developer needs, and about unnecessarily complex and time-consuming contracting procedures whose costs can exceed the benefits offered by smaller DER projects. To address these barriers, pilot participants may be able to:

1. Examine any legal issues related to 'special contracts' or 'undue discrimination' as defined by statute or the state commission, and *establish terms or boundaries* (e.g., dollar amounts, numbers or classes of customers, length of contract, geographic area, etc.) within which utilities are free to conclude pilot agreements with assured cost recovery and without *ex post* commission approval.

2. Ensure the flexibility needed to capture and allocate multiple DER value streams and share costs accordingly, by allowing willing parties (i.e., a utility and a customer, developer or aggregator) to structure *bi- or multilateral contracts* that create value for themselves and the public, so long as they do not unreasonably prejudice other utility customers.

3. Develop *model contract provisions* to reduce transactions costs (analogous to pre-qualifying equipment to expedite permitting), at least for contract elements likely to recur

on multiple DER projects. Model provisions will need to be adapted to actual project conditions, but participants may be able to save time and money by starting with some thoughtfully crafted options for addressing common or recurring issues. As they gain experience implementing different kinds of projects, they can refine and expand the model provisions available for future participants.

Smaller DER projects often encounter financing barriers as well. Various forms of financing are available to create value for multiple participants, and different parties can access different, sometimes innovative financing options that can benefit the project as a whole. Examples include:

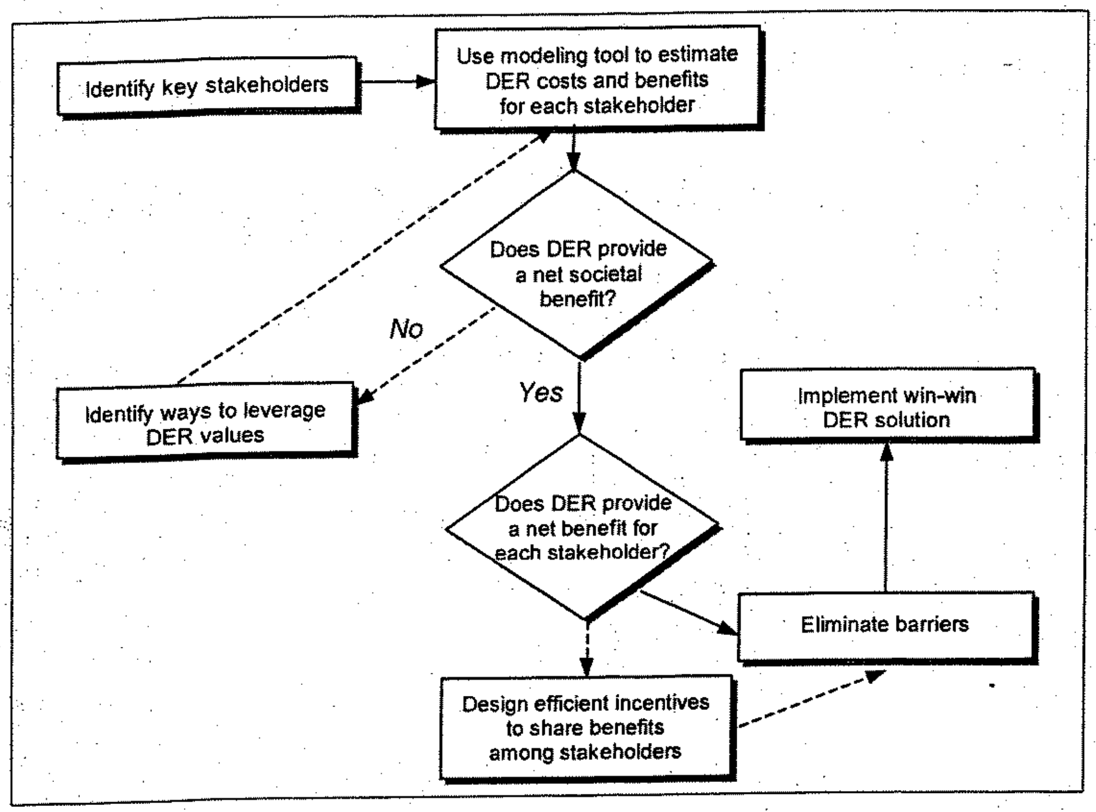
1. Customer internal capital budget financing
2. DER provider financing
3. Lease financing
4. Government-backed public financing (where public benefits are significant)
5. Equity markets financing
6. Rate-supported financing (where other utility customers stand to benefit)

These examples represent only a few of the avenues that pilot participants can consider, but they illustrate the kinds of approaches available under the framework's rubric of reducing or eliminating barriers. Each pilot program may encounter some of the barriers identified here, and will certainly confront others peculiar to the locality, the participants, the utility system, the technologies, and/or the need being addressed.

5. Using the Cost Benefit Model to Evaluate a CHP Pilot

The process chart below was introduced earlier as a guide for implementing pilot projects using the collaborative approach described in this Framework document.

Figure __. Process to Identify, Leverage, and Reallocate DER Costs and Benefits



The following example is given to illustrate the concept and show how it might work in practice.

Southern California Edison 800 kW CHP example

In this example, the modeling tool is used to estimate costs and benefits associated with an 800 kW natural gas cogeneration unit proposed to be installed by an SCE customer with 2000 kW demand and a 50% load factor. Other key assumptions include:

- a current market price electricity forecast at SP15 [South of Path 15]
- zero T&D avoided cost
- zero generation capacity avoided cost
- spot market purchases of 5% of total power supplied by SCE
- a medium 'generation multiplier' effect (equal to '3' in the model)
- emissions costs 'low'
- use of SCE's proposed 'GS-2' rate filed with the California PUC

The following table reproduces the modeling tool's 'Output Summary'. It shows the levelized annual net benefit (or cost, where the net benefit is negative) from the perspectives of (1) the DER customer, (2) utility shareholders and other ratepayers, and (3) societal interests. Based on the assumptions noted, this CHP application shows a small loss for the DER customer, positive net benefits for utility shareholders and/or other ratepayers (depending on how regulators allocate benefits), and a net cost from the incremental and net societal perspectives.

Figure __. 800 kW CHP costs and benefits, before leveraging or reallocating

Costs and Benefits			
Units Levelized $		**Analysis Horizon Years (20 Years Max)**	10
DER Customer			
Participant Cost Test: Is it worth it to the DER customer to install the DER?			
Annual Electricity Bill Savings	351,135.12	Annual Capital Cost	115,766.11
Annual Avoided Fuel Savings (Thermal)	141,592.01	DER Maintenance Cost	69,374.77
Wholesale Energy Sales	-	DER Fuel Cost	330,216.16
Sales of Renewable Energy Credits	-	Emissions Offset Purchases	9,891.91
CEC Buydown / CPUC Self-gen Program	32,157.25	Interconnection Study Cost	275.98
Incentive / Credit from Other Ratepayers	-	Insurance	-
Incentive from Public Funds / Tax Credit	-	Other Utility Upfront Costs	-
		Other Utility Operational Costs	-
Total Benefits	524,884.38	Total Costs	525,524.93
		Net Benefit	(640.55)
Utility Shareholders and Other Ratepayers			
RIM Test: How much will the impact be on earnings or rates?			
Avoided Wholesale Energy Purchases	411,893.43	Revenue Reductions Due to DER (e)	351,135.12
Avoided Generation Capacity	-	System Upgrades	-
Avoided T&D Capacity	-	Interconnection Study Cost	275.98
Customer Payment for Interconnection Study	275.98	Credit to DER Customer (b)	-
Credit from Public Funds / Tax Incentive (c)	-		
Total Benefits	412,169.41	Total Cost	351,411.10
		Net Benefit	60,758
Combined DER Customer, Shareholders, Other Ratepayers			
Total Resource Cost Test: What is the net tangible benefit that can be reallocated to produce a 'win-win'?			
Sum of DER Customer, Shareholder, and Other Ratepayer Perspectives			
		Net Benefit	[illegible]
Incremental Societal Value			
Societal Cost Test: What are the additional net intangible benefits?			
Reduced Central Generation Emissions	13,612.35	DER Emissions	60,400.77
		CEC Buydown / CPUC Self-gen Program (d	32,157.25
		Public Funds / Tax Credit to Utility (c)	-
		Public Funds / Tax Credit to Customer (a)	-
Additional Benefits	13,612.35	Additional Costs	92,558.02
		Incremental Societal Net Benefit	(78,945.67)
		Net Societal Benefit (TRC+Societal)	(18,827.92)

In this California CHP example, the customer loses $641 annually. Utility shareholders and/or other ratepayers gain about $61,000 annually, while society 'pays' nearly $79,000 (in the form of increased emissions and mandated self-generation incentives). Netting out the utility benefits, the cost to society is about $18,800. In terms of the process diagram on page 17, the question *"Does DER provide a net societal benefit?"* must be answered *"no"* for this example – unless strategies are available to leverage some CHP benefits. Continuing with the process diagram, then, the next step is to *"Identify ways to leverage DER values."*

STEP ONE: LEVERAGING DER VALUE

The model's Output Summary (above) shows that, of the sources of value (or benefits) potentially available to the utility and other ratepayers from this CHP project, only two have been recognized: substantial avoided wholesale energy purchases, and a nominal customer payment for an interconnection study. In particular, no benefit has been identified for either avoided generation or T&D capacity.

For collaborative participants interested in shaping a successful pilot, the next step would be to determine whether any of the strategies or options outlined earlier in the framework (or others similar to them) can usefully be applied to the proposed CHP application. If any of them can yield additional, monetizable benefits for the DER customer, the utility and/or other ratepayers, or society, then the participants need to explore how this CHP project can bring them to fruition. Once that is done, they can include the additional (leveraged) benefits in another iteration of the spreadsheet analysis, and recalculate a new set of costs and benefits for each stakeholder.

In this CHP example, it may be worth considering options 1 and 3 identified on page 12, i.e.:

1. *<u>Customers use on-site resources to create value in wholesale energy markets by</u>* –
   - a. running onsite generators to reduce load for demand response programs
   - b. running onsite generators to hedge hourly pricing contracts
   - c. curtailing load to participate in demand response programs …

3. *<u>Distribution utilities reduce their costs to upgrade or expand the grid to meet growing demand by</u>* –
   - a. using customer resources (efficiency improvements, CHP, clean baseload generation, etc.) to reduce energy use
   - b. using customer demand response resources (air conditioner controls, backup generation, operating limitations, etc.), to limit peak demand

Option 1 is available for CHP only if (a) the onsite generation capacity exceeds the electric and thermal requirements of the CHP application, and (b) the generation is available at times when wholesale power prices exceed the retail price. Here the opportunity would be to oversize the generator relative to the site's thermal load, and to use it as an incremental resource (Options 1.a. or b.).

Option 1.a. – running onsite generators to reduce load for demand response programs – could be available under current California pilot programs and, if successful, under more permanent programs. However, using the assumptions in this CHP example, this option creates minimal incremental value. Option 1.b. (hedging hourly pricing) is currently unavailable in California, leaving Option 3.a. to consider.

Option 3.a. can add value if the customer is able install its CHP in a distribution area where the local utility is planning to upgrade its grid to meet growing system demand. In that case, the collaborative would want to explore whether the customer's CHP installation could reduce circuit loading enough to defer the planned grid upgrade for some period of time. If it can, then the value of the deferral (arguably the carrying cost of the upgrade during the deferral period) could be considered as a benefit to the utility and included in the economic analysis. Any revenue loss to the utility from the project has already been recorded on the cost side, so the distribution deferral would add net value.

To assess this option, customer representatives would meet with utility planners or engineers to determine whether the grid's needs are compatible with the operational requirements for the customer's CHP. Utility planners may (and in some cases must[58]), seek assurances that the customer will not require backup power for the 800 kW load served by its CHP equipment if that equipment fails. This requirement can be satisfied in various ways, including utility control of a load-limiting device at the utility/customer interface point. In any case, if the customer and the utility can agree, they can collaborate to help the utility defer or even avoid the cost of additional facilities on its local grid.

The Output Summary reproduced below reflects additional assumptions – namely, that the CHP project is sited in an area where SCE plans to upgrade its system to meet growing demand, and that the CHP customer can assure the utility that grid backup will not be required for its load if the onsite generation fails. For estimation purposes, the model incorporates the California utilities' average costs for incremental distribution construction, and establishes low, medium and high ranges based on this information. The summary below shows the costs and benefits of avoiding construction of facilities in the 'high' incremental cost range. The information is presented on a levelized basis, with a 10-year horizon.

[58] The California PUC requires 'physical assurance' if distributed generation is to be considered as an alternative to distribution system upgrades. This means that the customer's load must automatically be curtailed if its generation fails. See D.03-02-068 in R.99-10-025, February 27, 2003 at p.10, note 2; p. 16; p. 19, Finding of Fact 7 and Conclusion of Law 3.

Figure __. 800 kW CHP costs and benefits, leveraged with high T&D value to the utility

Costs and Benefits			
Units: Levelized $		Analysis Horizon Years (20 Years Max)	10
DER Customer			
Participant Cost Test: Is it worth it to the DER customer to install the DER?			
Annual Electricity Bill Savings	351,135.12	Annual Capital Cost	115,766.11
Annual Avoided Fuel Savings (Thermal)	141,592.01	DER Maintenance Cost	69,374.77
Wholesale Energy Sales	-	DER Fuel Cost	330,216.16
Sales of Renewable Energy Credits	-	Emissions Offset Purchases	9,891.91
CEC Buydown / CPUC Self-gen Program	32,157.25	Interconnection Study Cost	275.98
Incentive / Credit from Other Ratepayers	-	Insurance	-
Incentive from Public Funds / Tax Credit	-	Other Utility Upfront Costs	-
		Other Utility Operational Costs	-
Total Benefits	524,884.38	Total Costs	525,524.93
		Net Benefit	(640.55)
Utility Shareholders and Other Ratepayers			
RIM Test: How much will the impact be on earnings or rates?			
Avoided Wholesale Energy Purchases	411,893.43	Revenue Reductions Due to DER (e)	351,135.12
Avoided Generation Capacity	-	System Upgrades	-
Avoided T&D Capacity	117,303.99	Interconnection Study Cost	275.98
Customer Payment for Interconnection Study	275.98	Credit to DER Customer (b)	-
Credit from Public Funds / Tax Incentive (c)	-		
Total Benefits	529,473.39	Total Cost	351,411.10
		Net Benefit	[illegible]
Combined DER Customer, Shareholders, Other Ratepayers			
Total Resource Cost Test: What is the net tangible benefit that can be reallocated to produce a 'win-win'?			
Sum of DER Customer, Shareholder, and Other Ratepayer Perspectives			
		Net Benefit	[illegible]
Incremental Societal Value			
Societal Cost Test: What are the additional net intangible benefits?			
Reduced Central Generation Emissions	13,612.35	DER Emissions	60,400.77
		CEC Buydown / CPUC Self-gen Program (d	32,157.25
		Public Funds / Tax Credit to Utility (c)	-
		Public Funds / Tax Credit to Customer (a)	-
Additional Benefits	13,612.35	Additional Costs	92,558.02
		Incremental Societal Net Benefit	(78,945.67)
		Net Societal Benefit (TRC+Societal)	[illegible]

Capturing this substantial "Avoided T&D Capacity" changes the 'Net Societal Benefit' in this example from a negative $18,800 to a positive $98,500. With this new information on T&D capacity value included through the modeling tool, the answer to the process chart's question *"Does DER provide a net societal benefit?"* changes from *"no"* to *"yes"*. However, all of the additional benefits accrue to the utility and/or other ratepayers, not to the DER customer or as an incremental benefit to society. The next challenge, then, is to see whether there are opportunities to re-allocate some of the benefits so that all key stakeholders are better off, or at least not worse off than they would be without the project.

STEP TWO: DESIGNING EFFICIENT INCENTIVES

To illustrate how the model can help assess the effects of various strategies and approaches described in the catalog and the framework, this section focuses on incentives that utilities and regulators can use to re-allocate the benefits of deferring utility construction through some form of value transfer from the utility to the customer. However, a few words about utility rate design are appropriate here. Traditional rate design has tended to assign utility cost recovery to fees for usage, rather than fees based on fixed charges (e.g. energy usage vs. demand charges). This means that high-load-factor CHP projects that reduce customer usage of utility-supplied power tend to result in favorable economics for the CHP customer, but revenue losses for the utility and thus negative impacts on utility shareholders and/or other ratepayers.

The model illustrates this if SCE's *existing* GS-2 rate is selected, rather than its *proposed* GS-2 rate. Running the CHP case using SCE's existing GS-2 rate results in a large benefit for the customer and a large loss for the utility and society. Even when "high" is chosen for the "Avoided T&D Capacity" selection, the economics remain unfavorable to the utility. Prospective DER customers might be inclined to favor this outcome in theory. However, they might rue it in practice, if the disincentive for utility participation means that CHP projects take longer and cost more to complete than they might otherwise, or if utility inertia or resistance means that few such projects go forward.

Comparing the modeling results for SCE's existing GS-2 rate with those for its proposed GS-2 rate illustrates that rate designs strongly affect stakeholder flexibility to re-allocate benefits in ways that can make DER work. Rates that recover a higher percentage of utility costs through fixed charges (such as SCE's proposed GS-2 rate) will discourage customer-side CHP projects, resulting in fewer projects, less favorable to customers and more favorable to utilities. Collaborative participants may need to re-examine some rate policies in effect in the pilot state, and decide whether more balanced experimental tariffs may be appropriate. The approach described below for creating a win-win CHP project could be difficult if a rate similar to SCE's existing GS-2 rate were in effect, since it would entail shifting some benefits from the DER customer to the utility. This may be a perfectly appropriate policy choice to encourage DER where it provides the broadest benefits, but may well seem counter-intuitive and counter-productive to DER and consumer advocates approaching the problem from more traditional perspectives.[59]

As noted elsewhere in this report, one approach advanced by stakeholders with differing perspectives is the concept of a 'distribution credit'. The basic idea is that a utility pays a customer or DER provider to deploy DER in targeted areas of its distribution network – areas where the utility faces costly and potentially deferrable system upgrades – provided that these DER meet predefined utility criteria for cost, dispatchability, reliability, etc. The payment will be based on the costs the utility expects to avoid or defer as a result of DER operations in the targeted area. The Output Summary reproduced below uses the same CHP project modeled

[59] Such reactions are not limited to non-utility DER advocates: the same can be said for utilities and regulators considering transferring some benefits from shareholders and other ratepayers to DER customers and providers where that makes sense to encourage least-cost or best-fit solutions.

earlier to show how this kind of distribution credit incentive could impact costs and benefits for each key stakeholder group or pilot program participant.

Figure __. <u>800 kW CHP costs and benefits, leveraged with high T&D value to the utility, partially reallocated to the DER customer through a 'distribution credit'</u>

Costs and Benefits			
Units: Levelized $		Analysis Horizon Years (20 Years Max)	10
DER Customer			
Participant Cost Test: Is it worth it to the DER customer to install the DER?			
Annual Electricity Bill Savings	351,135.12	Annual Capital Cost	115,766.11
Annual Avoided Fuel Savings (Thermal)	141,592.01	DER Maintenance Cost	69,374.77
Wholesale Energy Sales	-	DER Fuel Cost	330,216.16
Sales of Renewable Energy Credits	-	Emissions Offset Purchases	9,891.91
CEC Buydown / CPUC Self-gen Program	32,157.25	Interconnection Study Cost	275.98
Incentive / Credit from Other Ratepayers	85,000.00	Insurance	-
Incentive from Public Funds / Tax Credit	-	Other Utility Upfront Costs	-
		Other Utility Operational Costs	-
Total Benefits	609,884.38	Total Costs	525,524.93
		Net Benefit	[redacted]
Utility Shareholders and Other Ratepayers			
RIM Test: How much will the impact be on earnings or rates?			
Avoided Wholesale Energy Purchases	411,893.43	Revenue Reductions Due to DER (e)	351,135.12
Avoided Generation Capacity	-	System Upgrades	-
Avoided T&D Capacity	117,303.99	Interconnection Study Cost	275.98
Customer Payment for Interconnection Study	275.98	Credit to DER Customer (b)	85,000.00
Credit from Public Funds / Tax Incentive (c)	-		
Total Benefits	529,473.39	Total Cost	436,411.10
		Net Benefit	[redacted]
Combined DER Customer, Shareholders, Other Ratepayers			
Total Resource Cost Test: What is the net tangible benefit that can be reallocated to produce a 'win-win'?			
Sum of DER Customer, Shareholder, and Other Ratepayer Perspectives			
		Net Benefit	[redacted]
Incremental Societal Value			
Societal Cost Test: What are the additional net intangible benefits?			
Reduced Central Generation Emissions	13,612.35	DER Emissions	60,400.77
		CEC Buydown / CPUC Self-gen Program (d	32,157.25
		Public Funds / Tax Credit to Utility (c)	-
		Public Funds / Tax Credit to Customer (a)	-
Additional Benefits	13,612.35	Additional Costs	92,558.02
		Incremental Societal Net Benefit	(78,945.67)
		Net Societal Benefit (TRC+Societal)	[redacted]

In this example, the utility is willing to offer an $85,000 yearly incentive to customers who install a CHP system in a target area (within certain guidelines, as noted earlier). If the incentive enables a customer to proceed, the utility in this example avoids a levelized annual investment of $117,300 to expand its T&D capacity in the area. Shifting some of the benefits to the customer does not change the *incremental* societal benefit, but the project's *net* societal benefit remains positive.[60]

Returning to the process flowchart on page 17, the question "*Does DER provide a net benefit for each stakeholder?*" can now be answered "*Yes.*" The collaborative can now shift its attention to the third strategy – eliminating barriers – to increase the overall cost effectiveness of the project, possibly by shortening the time it takes to complete the project, reducing processing costs that result from unnecessary barriers, and looking for ways to work through transactional barriers.

STEP THREE: ELIMINATING BARRIERS

Depending on the particular CHP project, there may be opportunities to eliminate some of the permitting or market barriers identified earlier, thus reducing overall project costs. The model can reflect such cost reductions through reductions in the $/kW figures entered in the 'Input DER Cost' tab of the spreadsheet. To illustrate how the model can show the impacts of reducing barriers, another example may help – one that shows the impact of eliminating the financing transaction barrier mentioned earlier.

One difficulty in justifying the economics of CHP projects versus traditional utility infrastructure additions, has been the disparity in financing periods between customer lease or purchase financing (typically short-term, up to 10 years), and utility financing (typically long-term, often recovered over a 30-year asset life). The following example shows the cost and benefit effects of modifying the financing term of a CHP project. Previous assumptions remain intact, except that the 'DER Financing' input is increased from 10 to 20 years.

[60] The current version of the model does not take into account avoided emissions from any boiler that might be displaced by the CHP installation. If the model is refined to do this for purposes of actual pilot projects, many CHP projects may yield additional societal benefits.

Figure __. 800 kW CHP costs and benefits, leveraged with high T&D value to the utility, partially reallocated to the DER customer through a 'distribution credit', with 20-year financing

Costs and Benefits			
Units: Levelized $		Analysis Horizon Years (20 Years Max)	10
DER Customer			
Participant Cost Test: Is it worth it to the DER customer to install the DER?			
Annual Electricity Bill Savings	351,135.12	Annual Capital Cost	79,118.80
Annual Avoided Fuel Savings (Thermal)	141,592.01	DER Maintenance Cost	69,374.77
Wholesale Energy Sales	-	DER Fuel Cost	330,216.16
Sales of Renewable Energy Credits	-	Emissions Offset Purchases	9,891.91
CEC Buydown / CPUC Self-gen Program	32,157.25	Interconnection Study Cost	275.98
Incentive / Credit from Other Ratepayers	85,000.00	Insurance	-
Incentive from Public Funds / Tax Credit	-	Other Utility Upfront Costs	-
		Other Utility Operational Costs	-
Total Benefits	609,884.38	Total Costs	488,877.61
		Net Benefit	[illegible]
Utility Shareholders and Other Ratepayers			
RIM Test: How much will the impact be on earnings or rates?			
Avoided Wholesale Energy Purchases	411,893.43	Revenue Reductions Due to DER (e)	351,135.12
Avoided Generation Capacity	-	System Upgrades	-
Avoided T&D Capacity	117,303.99	Interconnection Study Cost	275.98
Customer Payment for Interconnection Study	275.98	Credit to DER Customer (b)	85,000.00
Credit from Public Funds / Tax Incentive (c)	-		
Total Benefits	529,473.39	Total Cost	436,411.10
		Net Benefit	[illegible]
Combined DER Customer, Shareholders, Other Ratepayers			
Total Resource Cost Test: What is the net tangible benefit that can be reallocated to produce a 'win-win'?			
Sum of DER Customer, Shareholder, and Other Ratepayer Perspectives			
		Net Benefit	[illegible]
Incremental Societal Value			
Societal Cost Test: What are the additional net intangible benefits?			
Reduced Central Generation Emissions	13,612.35	DER Emissions	60,400.77
		CEC Buydown / CPUC Self-gen Program (d	32,157.25
		Public Funds / Tax Credit to Utility (c)	-
		Public Funds / Tax Credit to Customer (a)	-
Additional Benefits	13,612.35	Additional Costs	92,558.02
		Incremental Societal Net Benefit	(78,945.67)
		Net Societal Benefit (TRC+Societal)	[illegible]

Increasing the model's 'DER Finance' term for the CHP equipment from 10 to 20 years reduces the annual cost of the equipment to the customer by nearly $37,000. In this example, this increases the 'Net Societal Benefit' dollar-for-dollar, by the same $37,000.[61] This benefit in the first years of the project can be re-allocated among project participants if necessary to support a win-win outcome.

[61] Although this particular example used a 20-year financing term, it also used a 10-year analysis horizon, effectively ignoring project capital costs beyond the tenth year. Depending on the project this may or may not significantly skew the results, which are presented here only to illustrate how the modeling tool can be used, and not to justify any particular project.

*   *   *

The CHP case described above illustrates a process that collaborative stakeholders can use to pursue the strategies and implementation options outlined in this framework. The cost-benefit model provides a template that all stakeholders can work with and refine, and a common tool they can use to gauge the impacts of various program and project choices. Although stakeholders will need to adapt it to different locales and expand it to accommodate other types of information unique to their situation, the tool will be enhanced in each case by combining it with lessons learned from the catalog; rate design and other considerations discussed in Chapter __; and process suggestions, value leveraging strategies and incentive approaches outlined here.