Valuing Distributed Energy:
Economic and Regulatory Challenges

EVENT SUMMARY & CONCLUSIONS

Princeton Roundtable (April 26, 2013)

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COLUMBIA UNIVERSITY
IN THE CITY OF NEW YORK

PRINCETON
UNIVERSITY

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I. Introduction

This paper synthesizes the discussion and identifies opportunities emerging from a Roundtable on "Valuing Distributed Energy: Economic and Regulatory Challenges," held at Princeton University on April 26, 2013. [i]

The Roundtable brought together a diverse and influential group of stakeholders, including state and federal utility regulators, utility and distributed energy company executives, a Regional Transmission Organization (RTO) CEO, economists, engineering and law professors, and environmental and consumer advocates. State regulators and utility representatives primarily came from Northeastern and Mid-Atlantic states, which operate within competitive power generation markets and RTOs. To encourage frank discussion, Roundtable leaders set a ground rule of non-attribution. Accordingly, this synopsis reflects comments made throughout the day, but does not identify particular speakers. The conclusions and recommendations do not purport to reflect a consensus of the participants, except where specifically indicated, but rather are drawn from inputs received through the Roundtable process.

The Roundtable's morning session consisted primarily of a structured discussion led by Travis Bradford of Columbia University and Anne Hoskins of Princeton University and PSEG. The afternoon began with a presentation on a recently deployed methodology for pricing distributed energy (DE) in Austin, Texas, followed by small group "breakout sessions" on the key elements of DE pricing, as well as a session on the issue of jurisdiction. The results of those discussions, as well as relevant comments made throughout the day on each topic, are included below.

The main point of agreement, repeated throughout the day by multiple participants, was that the goal of the Roundtable— determining the appropriate way to value distributed energy resources — is one of the most important challenges facing energy policymakers in the next decade. It is important for DE's advocates, who will need to ensure that DE's benefits are adequately compensated. It is equally important for the utility industry, which may be heading for a "policy train wreck" if it does not anticipate and adapt to the coming changes to the grid and the utility business model, and for consumers on both sides of the utility meter. Potential disruptive catalysts include falling costs of distributed generation, increasing adoption of energy efficiency and demand response programs, declining economic growth, and declining natural gas prices.

<u>Conclusion #1</u> - A more refined understanding of DE's value and costs is critical for answering important questions of cost-effectiveness, reliability, and equity among electricity infrastructure choices across consumers. These questions represent some of the most important challenges the industry faces today.

A background paper served as a framing document for the Roundtable discussion *(attached in the APPENDIX)*. It defined a broad range of DE, including energy efficiency, demand response, storage, and distributed generation (DG). However, the Roundtable discussion tended toward a focus on DG. Accordingly, this synopsis primarily discusses DG, although many of the observations about its valuation apply to demand response and energy efficiency.

The DG industry in the United States is still small, with less than 1% penetration nationwide, though higher in some places such as Hawaii, California and New Jersey, the country's leading markets on a per capita basis, but it is growing at approximately 40% per year.[ii] Costs for installed solar systems have fallen by half in the last two years alone, and are expected to continue falling as markets grow and become more efficient.[iii] There was widespread agreement from Roundtable participants that the impacts of this growth on the electricity industry are expected to be substantial. Given that utility fixed costs are recovered predominantly through variable rates, major growth in DG (similar to other forms of DE) presents a threat of revenue erosion. At the same time, DG holds promise in terms of delivering both customer service benefits (e.g., it potentially could provide electricity to key facilities during times of grid outages) and societal benefits (particularly environmental). The key challenge is how to balance DG's dual impacts as both a threat to the viability of an electricity system we all depend on, and as a potential solution to many societal problems, including the challenge of climate change.

Many Roundtable participants noted that we are at an important moment in time for having these discussions. Given the resurgence in natural gas exploration, and demands for reinforcement and investment in the transmission and distribution grids, we are facing critical investment decisions that will pre-figure 40, 50, or 60 years of lifestyle choices. Some raised questions over just how large a role DE, as opposed to centralized generation, will play in our future system. Although the Roundtable did not attempt to answer that question, one important related conclusion emerged:

Conclusion #2 - Proper price signals can help us make the right long-term choices in terms of the scale and type of future generation.

Shortcomings in Current Valuation Methods

The Roundtable began by examining shortcomings in the current valuation methods for DE. Net metering received particular criticism as lacking refinement in the way it measures the benefits and costs of DG. It might provide a sort of "rough justice" level of payment to these energy providers, but even if this is the case, there is a critical problem of transparency. It is notable that neither utilities nor DG providers *think* that the payment is treating them fairly. This is likely the case because the costs and benefits are not measured and incorporated explicitly, leading to observational bias and a view of impacts based on historical precedent and heuristics. Moving to a more transparent system for pricing DG should help satisfy everyone involved.

The valuation concerns that participants identified as needing attention most urgently include:

1. The underlying grid system needs to be paid for, and customers who do not install DE will pay an increasing burden. Lower-income customers could bear a disproportionate burden without corresponding benefits as penetration of distributed generation increases.
2. DE provides many benefits to the grid and to society that may not be adequately compensated in current pricing mechanisms. There is a need to identify and explicitly value these benefits.
3. Retail prices often fail to accurately reflect the price of wholesale power at a given time. Customers see a "dumb" price and give little thought to the system. Poor alignment of wholesale and retail prices, such as the lack of real time pricing, impedes proper signals about DE's relative value, although full alignment on the highest peak usage day of the year may not be possible or socially desirable.
4. Some capital investments—particularly in emerging technologies—cannot obtain necessary financing unless they have visibility on prices over the life of the capital asset. As a result, not all DE interventions can utilize short-term pricing mechanisms, but instead need price terms that exist for the duration of the capital investment.

Conclusion #3 – A price mechanism that does not include currently misallocated costs ("Pecuniary Costs" as defined herein), currently misallocated benefits ("Pecuniary Benefits" as defined herein), and externality values is incomplete and will lead us to make poor or wasteful capital allocation decisions.

II. THEMES IN DISTRIBUTED ENERGY VALUATION

Several themes relating to DE valuation emerged throughout the day and across topics. These themes, and the key contents of the discussions around them, are synthesized below.

Variable vs. Fixed Rate Recovery Methods

Participants discussed whether the "kilowatt-hour" (kWh) is the right metric for measuring customers' energy consumption. On the plus side, it is easily measured, and the ability to use actual meter data over model data is preferable. On the other hand, charging retail customers differently could break the strong volumetric link between consumption and revenue and facilitate continued broad-based funding of the grid. Neither all fixed charge nor all volumetric charge mechanisms correctly reflect the underlying cost structures of today's utility provider, and finding the right balance is important. Though no conclusion was reached, a number of options were discussed and explored:

(1) Customers could be charged per square foot, with the utility having an incentive to provide quality service at the least kWh possible. However, this approach could deter customers from investing in energy efficiency, and may penalize those who already have.

(2) A model of "rate plans" could be tested much like those used for cell phones, where customers choose a plan based on a number of kWh and pay extra for exceeding the allotment of kWhs. However, there might be less tolerance for this in the electricity sector than in the cell phone industry, where there was a new emerging technology, not simply a switch in pricing methods.

(3) DG customers could be charged a connection fee and a back-up charge to cover fixed costs, plus a variable charge based on the energy used (which could be an inverted fee to discourage consumption). Interconnection charge levels could change with increasing levels of DG penetration, as DG impacts on the grid change. It was also noted that connection fees for DG can serve as barriers to DG deployment if the fees are unreasonably high.

Impact of Duration on Pricing

Differing time scales can result in different price signals to DE. Roundtable participants noted that both short and long term signals are needed: short-term price signals incentivize quick reactions that maximize efficiency on an hourly and daily basis (perhaps more suitable for technologies that aim to relieve short-term capacity constraints); long-term signals are necessary for capital-intensive DE to have the assurance to drive investment (better for creating longer term energy investments, especially those with little to no fuel exposure). Forward capacity markets play an important role in sending an appropriate forward fixed cost signal to participants, thereby driving investment. A recurring theme was that demand response (DR) and energy efficiency (EE) investments have responded to these market signals, and in turn, DE's participation in these markets has lowered capacity clearing prices.

Sensitivity to Penetration Levels

There is a potential harmony to be explored between the short-term needs of DG providers and the longer-term needs of utilities. Right now, DE's pecuniary costs (intermittency and fixed charge coverage, for instance) on the electricity system are relatively low due to its low penetration, but these costs could escalate in the longer term as more DE comes on-line. Conversely, some of the benefits (particularly capacity value and merit order benefits) that DE provides are highest at low levels of penetration. This argues that while seemingly high today, DE value measures may not be inappropriate, but might also argue that value measures should be reduced over time if Pecuniary Benefits diminish and Pecuniary Costs of integration rise.

Type of DG – Natural Gas vs. Renewable

Not all types of DG are created equal, and there was discussion over the possible proliferation of natural gas DG through combined heat and power and fuel cells. Some noted that natural gas DG provides a promising option for those customers seeking reliability and security, as evidenced by its rising popularity in the wake of extended power outages caused by Super-storm Sandy. Small, efficient natural gas units could be the first step in leading us towards a more decentralized system, with renewable DG following on its heels. Some cautioned against relying on the path of natural gas DG due to long-term price risk and emissions of carbon dioxide and methane, and instead supported focusing on facilitating renewable DG. Suggestions were made that DG pricing could/should accurately reflect the differing levels of social benefits provided by different DG sources.

Utilities' Competing Priorities

The social benefit of electric utilities is to simultaneously maximize reliability and minimize costs. Although certainly aware of the challenges of DE, utilities and consumer advocates in the mid-Atlantic and Northeast are currently spending much of their energy grappling the pressing challenge of hardening the system in response to Super-storm Sandy. Reliability is still utilities' top priority. There is realization that attention must be paid to the issue of DE penetration as well, or else utilities will end up "in a world of hurt" as their role in society transforms. A sort of "vicious cycle" could arise, where utilities face pressure to harden the system for reliability, thereby increasing rates, making DE more cost-competitive, and exacerbating the problem from a utility perspective. For this reason, proactively thinking about how to create appropriate price structures for DE is critical.

Protecting Non-Participating Consumers

One prominent concern about the growing use of DG is that as utilities' customer base shrinks, remaining system costs will be spread over a smaller group of traditional consumers that could be disproportionately lower-income. Unless rate adjustments are made, the claims suggest, low-income consumers might effectively subsidize more affluent DG-deploying consumers; however, some questioned whether DG is really correlated with "high-income," as low- and middle-income consumers are increasingly installing DG through use of innovative financing mechanisms. This concern highlighted the importance of the Roundtable's task: creating a transparent calculus that properly values costs and benefits so that non-participating consumers, and their advocates, can better understand whether and how DG adds value to the system. More work is required to better understand the issue of DG's equity implications.

Potential DE Providers

DE deployment can occur through multiple parties: regulated utilities, conventional independent power providers, third-party generators, and self-motivated customers. An ideal price signal would be agnostic as to the nature of the provider, and would send the proper incentives to any of these entities. DE firms expressed openness about having utilities enter the DE space on a competitive basis or in partnership with them. Discussion ensued on how utilities could be incentivized to participate in DG deployment, with suggestions ranging from including DG deployment in the regulated utility rate base, to enabling utilities to take advantage of the incentives that DG firms typically rely upon. Utilities might also be used to deploy DG in spaces lacking commercial viability but offering significant societal benefits, such as the use of utility investment to deploy DG in brownfields in NJ. Utilities can also serve the role of system manager of the distribution network, which will become increasingly important as larger numbers of DE providers enter the system and the grid is upgraded with smarter technologies. Utilities have expertise and ability to coordinate the system when deploying utility controlled, utility scaled DG. Caution was urged, however, to ensure that any competition would be fair and open, without providing undue advantage to those with a natural regulated territory allowance.

Learning from Past Mistakes

Roundtable participants presented a few examples of other industries where disruptive technologies caused sub-optimal transitions that might provide learning opportunities.

Comparison was made to the trolley system. Society taxed trolley users, and let the trolley infrastructure languish, to pay for the transition to highways and automobiles without fully understanding the value being lost. In hindsight, the significant unrealized value in the trolley infrastructure is clear, but cannot easily be recovered. Similarly, there may be implicit, or public good, value to the centralized, socialized grid infrastructure that could be lost or undermined in an increasingly distributed electricity system.

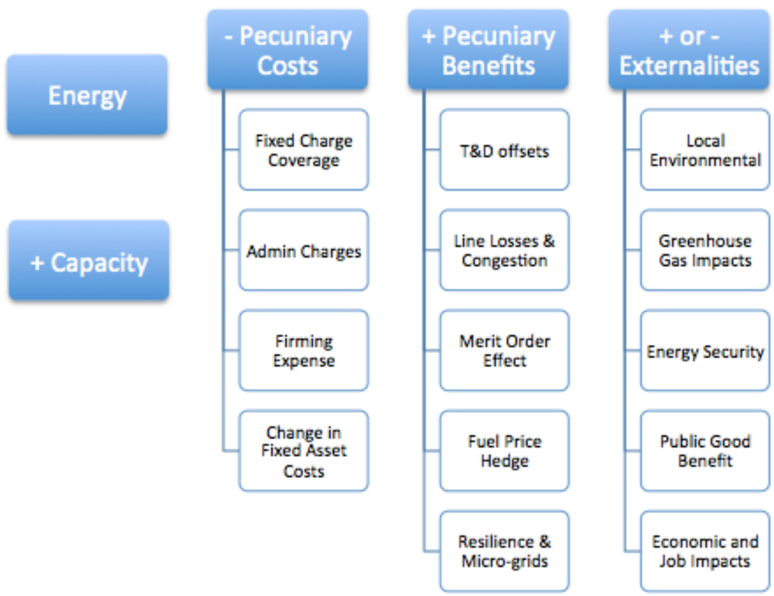
Perhaps the most analogous example to the challenge facing the electricity industry today is the more recent experience of the telecommunications industry. Customers who have not fully transitioned to cellular service bear the costs of the traditional, copper land-line infrastructure, and traditional telecom utilities have seen their landline business models falter. In some states, innovative models for telecommunications regulation emerged, eliminating rate cases, decoupling revenues from volume, and providing rewards for customer satisfaction. Unfortunately, the telecommunications experience is not completely transferable. Until a source of economical electric storage exists, most DE customers are reliant on the electric grid as a back-up service. Currently, DE customers cannot "cut the cord" to the degree cell phone customers can and have. Further, there is some notion that access to electricity (both individually and societally) is more of an essential service than access to communications, and therefore much more important to maintain.

III. Building Up a Valuation Model

Participants recognized that we need a better way to price DE as it reaches greater levels of maturity—one that accurately reflects both its costs and its benefits. The Roundtable reviewed proposed elements of a valuation framework as described in the Roundtable background paper. These elements include (1) energy and capacity values, (2) pecuniary costs, (3) pecuniary benefits, and (4) non-pecuniary costs and benefits (externalities).

Figure 1 summarizes some key considerations mentioned during the Roundtable for inclusion within each of these elements; more detailed discussion follows.

Figure 1. Key Elements of DE Valuation



1 - Choosing the Correct Energy and Capacity Values

As with other sources of electricity, DE provides a direct energy benefit and can provide a capacity benefit. Roundtable participants did not delve deeply into these two elements of valuation, although there was discussion about the merits of compensating the capacity value of DE through a fixed payment, while compensating the energy value through a variable payment. There was also recognition that compensating DE only for Energy value (for instance by using the avoided wholesale power price alone) intrinsically pays a zero capacity value, and does not compensate for other benefits provided.

A number of participants voiced their expectation that DE has potential to lower capacity-related costs borne by customers. This includes value from potentially needing fewer central generation units. If the use of peaking generation capacity during the few hottest days in the summer can be reduced, supplementary infrastructure can be avoided, thereby saving customers expense. The analysis requires both identifying the economic costs of capacity and gaining a better understanding of the technical impact that DE has on the grid and on the continued need for traditional capacity requirements.

2 - Pecuniary Costs Borne by Others

Participants recognized that DE—and in particular, DG—imposes costs upon the existing electricity system. Proper recovery of these costs is a key concern for utilities and consumer advocates.

Fixed charge coverage - Today's dominant model of residential cost recovery involves using lower fixed charges and higher volumetric pricing to recover both fixed and variable costs. Net-metered DG providers/customers use the grid as a de facto battery system – adding excess power at times, and drawing off of it when their systems do not fulfill their demand. Until there is widespread, affordable storage, this will be an inherent feature of DG. Currently, when DG providers reduce energy consumed from the grid, the fixed costs of the system remain, posing a risk that utilities may not be made whole by DG providers for the backup services provided to them. As more customers install DG systems (and become DG providers), this risk increases.

Firming Expense – Many renewable DG alternatives are intermittent (i.e. not dispatchable), and some additional cost must be incurred to ensure adequate capacity is available. It was noted that the need for back-up generation could decrease as the number of DG units increase, with one participant commenting that "if you have one 100 MW facility that goes offline, you need 100 MW worth of backup, but if you have 100 one MW facilities, you probably don't need as much standby at once [thus reducing your costs]."

Conversely, the impact on the underlying distribution grid could increase with the number of generation inputs. These new costs can be thought of as falling into two categories. The first is "status quo" costs: those paid simply to ensure that, with the addition of DG, the system continues to function as is, including maintenance and reinforcement of the underlying distribution and transmission grid. This category includes standby costs – the cost of keeping base load plants running at partial capacity to compensate for the intermittency of renewable DG.

Administration and Interconnection Costs - The second category is administration costs, and includes those costs the utility may undertake to fully optimize the integration of DG, such as monitoring systems and transformers that facilitate the flow of power from DG systems into the larger grid, interconnection costs for the impacts DG imposes on transmission and distribution, and the administrative costs of a more complex billing process. Expected DE penetration levels need to be incorporated into the analysis, as the value will change with penetration levels.

While these potential costs have been identified by utilities, additional data is necessary to demonstrate the magnitude of these costs. Additional exploration is also warranted for opportunities to re-design or innovate the distribution system, which could relieve the need for certain other network investments.

Unless these pecuniary costs are addressed and effectively included in DG assessments before the penetration of DG systems reaches a significant scale, utilities and public service commissions will need to consider other options, including raising customer rates or changing rate structures (towards more flat rate or block pricing). Raising rates brings up equity concerns, particularly if lower-income customers bear an increasing share of cost increases. On the other hand, imposing these costs on DG providers too soon might risk stifling an industry that is not yet "in the black."

3 - Pecuniary Benefits Received by Others

There is still disagreement between utility and DG providers about whether DG providers are in fact paying for use of the grid when they engage in net metering, given the countervailing pecuniary benefits that should also be considered. Roundtable participants recognized that DE provides real, pecuniary benefits that need to be considered in a complete pricing mechanism. These benefits include avoided transmission and distribution investment, avoided line losses and congestion, the merit order effect, a fuel price hedge and resiliency. Throughout the conversation, it was observed that resiliency represents an important new and high-cost mandate in the Northeast, and that micro-grids are gaining attention as a resiliency strategy. It is possible that resiliency may dwarf several of these other benefits in these regions.

Resiliency - In the post-Sandy environment, resiliency is viewed one of the most important benefits of DE. DG, and in particular micro-grids—small agglomerations of DE that are capable of being "islanded" from the larger grid—can function as a type of insurance policy or hedge to maintain electricity supply during grid-wide outages. This pecuniary benefit can be quantified by measuring avoided economic losses during grid outages. Many businesses are already paying a premium for distributed power, for example by buying an onsite generator or fuel cell.

DE may also foster resiliency against the threat of a cyber attack, although questions were raised as to whether a distributed system is actually more susceptible to cyber risks. Micro-grids mean that there is not a single, central system that can be shut down, but they also create more points of entry. The pecuniary value of these resiliency benefits may be particularly hard to calculate.

There is a temporal aspect to many of DE's benefits; some are highest early in DE's penetration; others build over time. For example, DE can help offset **transmission and distribution development**, but not until it exists at a level significant enough to change plans for upgrades or capital budgeting. On the other hand, the micro-grid resiliency value of DE is highest in the first instance, when it can guarantee the uninterrupted existence of vital services. The thousandth micro-grid will have a lower value, given that it will provide for convenience rather than necessity.

Line loss and congestion benefits vary temporally and based on the distance between the alternative energy source and the end user. Like transmission and distribution offsets, line loss and congestion benefits grow with levels of penetration.

The **merit order effect** reflects DE's impact on wholesale market dynamics and can be measured through calculating the differential between what the price would have been if one more generator had been called, and the price that was actually paid because that generator did not participate in the market.

Other benefits such as the value of the **fuel price hedge** that non-fuel based DE interventions provide, VAR Voltage support, and black start capability round out the list of pecuniary benefits that should be evaluated and included in any valuation effort.

4 - Non-Pecuniary Benefits and Costs – Externalities

The value of DE is not fully captured within a calculus that rewards only straightforward pecuniary benefits or assesses only direct pecuniary costs. If used on a significant enough scale, many DE resources have potential to help lower greenhouse gas emissions, as well as mitigate other environmental impacts, and to provide for economic development, jobs, and energy security. There are also possible societal costs, including losing access to a ubiquitous grid that can ensure universal access to basic electrification. To fully value DE, societal benefits and costs should be explicitly calculated. Many methodologies exist for quantifying and monetizing these benefits. Once calculated, policymakers and regulators will need to determine how to account for them—either as part of a ratemaking system, or through an exogenous price, tax (credit or assessment), or subsidy.

Carbon benefits emerged as the externality of most concern. DG can produce positive or negative externalities in this regard: renewable DG and energy efficiency can reduce greenhouse gas emissions by displacing fossil-fueled generation, whereas distributed natural gas systems emit carbon (albeit less than coal- fired systems) and fugitive methane that presently is not priced into the systems. It was noted that some DG requires backup for intermittent/variable power, which could mean that fossil- fueled backup power will be ramping up and down, thus increasing emissions. Participants further noted that a price on carbon would help send proper signals about the type and amount of DG to develop.

DE can also provide **environmental benefits**, including air quality benefits and water benefits. Conversely, diesel or other fossil-fueled DG has negative local air quality impacts, which will be more difficult to manage and mitigate than those from central station fossil generation plants. In short, a decentralized system may have positive or negative externalities, and these should be appropriately recognized and imputed.

DE may also have health impacts and potential innovation benefits. Policies that promote DE can help drive small-scale innovations like fuel cells. **Economic development and jobs** may also accompany DE, although any offsetting job losses from conventional energy generators would need to be captured in a valuation methodology.

There is also a value to the existing, functioning grid that may be lost if we transition without planning to wide-spread DG. There could be an "**infrastructure externality**," or loss of public good, if the centralized system erodes before an alternative distributed system matures.

There are legal questions regarding which is the appropriate entity to assign value to these externalities. State public utilities commissions may be constrained in their ability to consider certain externalities by FERC precedent and state authorizing legislation. A national carbon market would help send a price signal about the social costs of carbon coming from electricity generation, but is not likely to be forthcoming soon. In its absence, regional or state markets may fulfill this function. EPA has the ability to regulate carbon and air emissions under the Clean Air Act, and for pollutants where it has done so, utilities feel a direct, pecuniary cost to their emissions. FERC lacks authority to create price differentials based on externalities. It could not, for example, set up a market rule that would pay diesel demand response less than cleaner demand response—it is up to the EPA or states to set limitations on diesel demand response.

An Application of the Methodology: Austin Energy Value of Solar

The approach of separately identifying and valuing the costs and benefits of DG exists in Austin, Texas. Roundtable participants received information about the Austin approach prior to breaking into groups, as a case study of how an explicit DG valuation system could be structured.

Austin Energy, the municipal utility for Austin, Texas, replaced net metering with a pricing approach that it terms the "Value of Solar" approach. This approach separately meters consumption and production, and differentiates the DE customer's payment to his utility and the payment that the DE customer receives for the value of the solar energy that he provides. Consumption is billed using existing utility tariffs. Production is credited using the "Value of Solar," a calculation that includes values to the utility (e.g., avoided fuel costs, avoided plant operating and maintenance costs, etc.) and values to ratepayers and taxpayers (e.g., economic development value, environmental value, etc.). In this way, utilities get "made whole" and can maintain the grid and their current rate structure, while the DG provider is paid a fixed price that drives appropriate financing signals. The transparency of this rate structure alleviates confusion and misunderstanding about the transaction.

When applied in Austin, this methodology initially produced a solar tariff rate *higher* than the retail price of electricity because long-term pricing was used and the value for the fuel price hedge provided by solar was included. The value, however, could vary in jurisdictions based upon which costs and benefits are included, as well as the inputs measured and derived in the regulatory process. It could also vary over time as relative value for costs and benefits change with market conditions or levels of penetration. The Austin tariff provides a method whereby regulators and stakeholders can have a transparent conversation about the benefits and costs to include in the tariff, in order to produce a data-driven result.

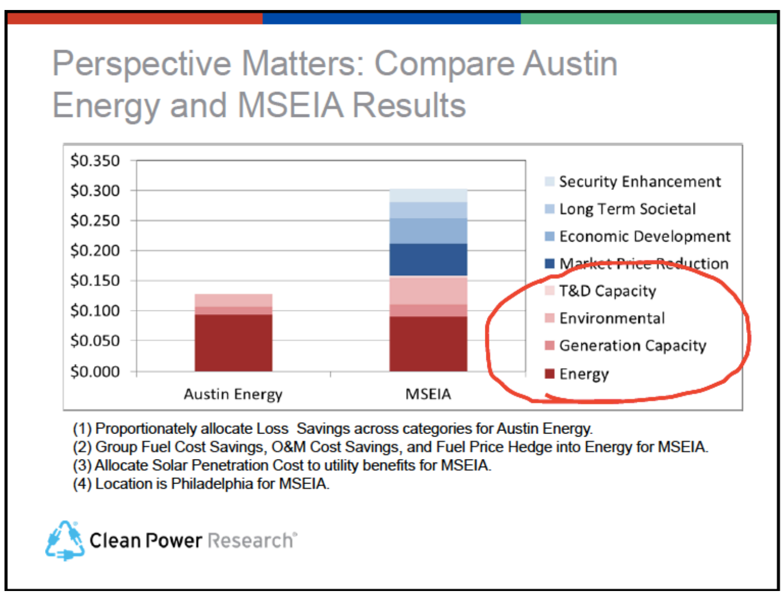


Figure 2. A sample of the Austin Energy Value of Solar Tariff (VOST) (Courtesy: Tom Hoff)

How To Implement Reform: Jurisdictional Challenges and Opportunities

One issue that reappeared throughout the day was jurisdiction. Questions arose both in terms of whether federal and/or state regulatory agencies *should* be undertaking the task of valuing DE, and which of them *could* undertake this task under the constraints imposed by the Federal Power Act (FPA) and the Public Utilities Regulatory Policies Act (PURPA). Clarity will help to enable effective distributed energy valuation.

There are many open questions regarding the legal constraints faced by states in DE valuation. States are not certain how far their authority extends to regulate the price of DE entering into the electricity grid, or to include in their pricing all of the relevant elements of DE's valuation. These challenges were showcased in California's recent attempt to require its utilities to offer a certain price to small combined heat and power (CHP) generating facilities—an attempt that was challenged by utilities at the FERC, asserting CA was preempted by the FPA.[iv] The results of that proceeding illustrate both the complex nature of the problem and the ways in which FERC is proactively working to provide a path forward for states. In that case, FERC ruled that California *did* have the authority to proceed with its CHP pricing plan, so long as it did so under the auspices of PURPA and followed relevant FERC precedent on the rates that CHP could be paid.[v] FERC also clarified the considerations that could factor into setting prices under PURPA.[vi] While this decision did not fully answer state questions about DE valuation, it provides an opening for states to move forward.

On a more general policy level, states struggle with our balkanized regulatory system. Some participants suggested that the federal government take on the role of promoting clean energy, as states could end up paying an unfair premium to address what is a national/international problem. Conversely, others asserted that states reap benefits from promoting clean energy that should incentivize them to act.

At the federal level, FERC has taken steps to encourage appropriate valuation of DE while remaining conscious of states' traditional role in resource planning, siting, and retail ratemaking. In particular, FERC's Order 1000 requires that regional transmission planners give comparable consideration to "non-transmission alternatives" and take into account state public policy requirements that may drive transmission needs.[vii] There were questions about the proper reach of Order 1000 in this regard. While the DOE does not have regulatory authority to impose a pricing mechanism, it can serve a necessary convening, coordinating and technical/regulatory assistance role, as well as a funding role for technology and regulatory model development. Other agencies and entities may have specialized roles to play in valuing DE. The Department of Defense, for example, is demonstrating the security benefits of utilizing more diverse sources of energy by implementing microgrids and other distributed resources on its bases.

Regions were identified as a possible locus for some DE policy-making. Many of DE's benefits – jobs, clean air, business development—occur at a regional scale rather than within state-specific boundaries. In response to FERC Order 1000, RTOs are determining how their systems should operate going forward. This might provide a good space in which to discuss DE valuation in regional markets. Reforms at the ISO/RTO level could prove important in having the transmission and distribution benefits of DE better incorporated into decision-making.

The Regional Greenhouse Gas Initiative (RGGI) provides a model of how states might work cooperatively on clean energy policy. States might consider forming more robust partnerships through Interstate Compacts, like the Delaware River Basin Interstate Compact (though these would require Congressional approval under the Compact Clause). Perhaps regional compacts could overcome the hurdle of states not wanting to act alone or be the first mover in significantly restructuring DE valuation.

Discussion also occurred over the particular jurisdictional issues related to storage, which may ultimately be central to the viability of DG. Under FERC rules, storage can be treated as generation, transmission, or distribution, depending on its usage (for energy, capacity, or regulation).[viii] RTOs will play an important role in valuation and adoption of storage as they build assumptions about storage into their transmission and generation models. FERC rules on the treatment of storage will impact DE deployment. Local distribution utilities can also facilitate storage deployment by using it to support service in congested locations.

IV. Conclusions and Moving Forward

Above all, the Roundtable provided a neutral and open environment for key leaders to share concerns and express ideas for moving beyond debate and into constructive engagement on how to value distributed energy. Participants acknowledged the fact that the electric industry is facing changes that provide a moment of opportunity for re-examining outdated pricing structures. DE is growing, and is bringing with it exciting benefits and new challenges. Neither the electric grid nor the utility regulatory landscape is likely to change overnight; it may take small, incremental steps. Having an inclusive conversation now about the issues raised by the increasing penetration of DE and a framework for measuring its actual costs and benefits can make the transition more efficient and fair.

Although a perfect algorithm may be difficult to achieve, clear delineation of significant cost and benefit impacts can improve the status quo of opaque DE pricing signals that leave all parties feeling removed from the process and potentially disadvantaged. The Roundtable recognized many of the core elements involved in pricing DE, and began to explore ways to measure these elements. The core categories of capacity/energy; pecuniary costs; pecuniary benefits; and externalities provided an organizing framework that facilitated productive consideration from varying stakeholder representatives. We believe the model can be used as a starting point for regulatory commissions. There was recognition that the proposed framework could be useful for organizing analysis and regulatory review of proposed regulatory mechanisms (including feed-in tariffs, stand-by charges, Integrated Resource Plans, and market price referents).

Participants reported that one of the most helpful aspects of the Roundtable was that it enabled them to better understand the perspectives of the various players involved in the DE sphere, and to validate each other's concerns as important and real. Over the course of the Roundtable and in subsequent feedback, we received suggestions from participants for potential next steps:

1. Collect baseline data that was unavailable to participants, for example:
    a. The current proportion of fixed and volumetric charges for residential and commercial customers across various jurisdictions
    b. Income levels of current residential DE customers to determine if cross-subsidization across income levels is occurring
    c. A reliable range of forward cost curves of DE components and installations for planning purposes
2. Expand or replicate the Roundtable conversation in other regional groupings, including perhaps Western Region, Midwest Region, and the South – each with unique elements. Include a broad range of stakeholders, including federal and state regulators, utilities, DE providers, consumer and environmental organizations and academic experts.
3. Develop formal models of distribution networks to derive empirical data for inputs into the framework. For example, measure how the capacity and energy values of DG solar change as penetration increases and measure the physical impacts on the grid with changing penetration. Model the range of relative environmental externalities of replacing central-station generation (coal, natural gas and nuclear) with distributed generation (renewable, gas, diesel, bio-fuels), with varying fuel mix assumptions and levels of penetration.
4. Conduct legal research to clarify the jurisdictional questions raised by the Roundtable. In particular, further research into state authority to adopt a comprehensive DE valuation methodology might prove useful.

5. Pursue an actual valuation process through a state regulatory proceeding (perhaps on a trial basis), so that the general ideas discussed at the Roundtable can be turned into a concrete proposal and test case. Include a pricing mechanism that incorporates real-time pricing elements and facilitates cost-minimization, including the cost of obtaining financing.

6. Convene an ongoing group of balanced participants to follow up the results here by:

    a. Surveying, evaluating, and publishing results of existing methods of calculating the various value elements included in the framework.

    b. Commissioning data collection to support metric development, where necessary.

    c. Recommending best practices for others to use in modeling their own intervention.

Many members of the Roundtable have individually expressed interest in working on these issues going forward and to link these efforts to others pursuing the same objectives around the country and around the world. It is our sincere belief that only through broad cooperation and collaboration can we hope to achieve a quick and comprehensive set of solutions that will benefit all stakeholders in this important transformation.

Summary of Conclusions

Conclusion #1 - A more refined understanding of DE's value and costs is critical for answering important questions of cost-effectiveness, reliability, and equity among electricity infrastructure choices across consumers. These questions represent some of the most important challenges the industry faces today.

Conclusion #2 - Proper price signals can help us make the right long-term choices in terms of the scale and type of future generation.

Conclusion #3 – A price mechanism that does not include currently misallocated costs ("Pecuniary Costs" as defined herein), currently misallocated benefits ("Pecuniary Benefits" as defined herein), and externality values is incomplete and will lead us to make poor or wasteful capital allocation decisions.

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[i] The Roundtable was co-hosted by Princeton University's Andlinger Center for Energy and the Environment and its Energy and Environment Corporate Affiliates Program and Columbia University's School of International and Public Affairs, Center for Climate Change Law, and Center on Global Energy. The Roundtable was organized and moderated by Anne Hoskins, Visitor in Residence at the Princeton Corporate Affiliates Program and Senior Vice President at PSEG, and Travis Bradford, Professor of Professional Practice at Columbia. A number of students and post-doctorate staff participated in recording and synthesizing the Roundtable discussions, including Shelley Welton, Mark Walker, Harry Godfrey, Alice Cowman, Jorge Ordonez-Malagon, and Jackie Wong.

[ii] *See, e.g.*, Cal. Pub. Utils. Comm'n, *California Solar Initiative –Annual Program Assessment*, at 19-22, *available at* http://www.cpuc.ca.gov/NR/rdonlyres/0C43123F-5924-4DBE-9AD2-8F07710E3850/0/CASolarInitiativeCSIAnnualProgAssessmtJune2012FINAL.pdf (showing growth in California's solar distributed generation over the past decade and estimating 38% growth in solar capacity in 2012); J. Hernández-Moro, J.M. Martínez-Duart, *Analytical model for solar PV and CSP electricity costs: Present LCOE values and their future evolution*, RENEWABLE AND SUSTAINABLE ENERGY REV. VOL. 20:119, 119 (April 2013) (noting that solar has grown at 40% over the last decade); Anne C. Mulkern, *Utilities challenge net metering as solar power expands in California*, CLIMATEWIRE**,** April 2, 2013 (noting that solar now makes up 1% of California's energy supply, but is projected to grow to 4% over the next decade).

[iii] *See* David Feldman et al., *Photovoltaic (PV) Pricing Trends: Historical, Recent, and Near-Term Projections*, at v (Nat'l Renewable Energy Lab. & Lawrence Berkeley Nat'l Lab. Tech. Rep. No. DOE/GO-102012-3839, November 2012) (explaining that the cost of solar fell 25-29% between 2010 and 2011, and estimating that the "global module average selling price will decline from $1.37/Win 2011 to approximately $0.74/W by 2013").

[iv] *See* Cal. Pub. Utils. Comm'n, 133 FERC ¶ 61,059 (2010).

[v] *Id.* at P.5.

[vi] *Id.* at P.26.

[vii] See Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000, 76 Fed. Reg. 49842 (Aug. 11, 2011), 136 FERC Stats. & Regs. ¶ 61051, at ¶¶ 6, 203-16 (2011).

[viii] W. Grid Dev., LLC, 130 FERC ¶ 61056, at P44 (Jan. 21, 2010).

APPENDIX – PRE-EVENT WORKING PAPER

Valuing Distributed Energy: Economic and Regulatory Challenges

Working paper for Princeton Roundtable (April 26, 2013)

TRAVIS BRADFORD and ANNE HOSKINS

> "The timing of such transformative changes is unclear, but with the potential for forthcoming technological innovation becoming economically viable due to this confluence of forces, the industry and its stakeholders must proactively assess the impacts and alternatives available to address disruptive challenges in a timely manner."
> – "Disruptive Challenges," Edison Electric Institute, 2013

COLUMBIA UNIVERSITY IN THE CITY OF NEW YORK

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**** This document was prepared in advance by the authors and is intended solely for the purpose of stimulating discussion of the Roundtable, and does not represent the official policies, positions, opinions or views of the Participants or Organizations involved, including Columbia University, Princeton University or PSEG. ****

I. Background and Introduction

The rise of Distributed Energy (DE) resources – including Distributed Generation (DG), Energy Efficiency (EE), Demand Response (DR), and Customer-Sited Storage – is changing how the grid functions. As the grid becomes increasingly distributed, opportunities and risks are likely to grow, and must be managed.

Electricity customers are becoming increasingly focused on the need to have access to reliable, affordable and sustainable sources of energy. Technological developments and cost reductions in solar panels, smart meters, and battery storage provide promise of falling costs and smarter infrastructure. There is growing recognition that DE resources can provide benefits to customers and to the power system, but also concerns about valuation, integration and operational cost allocation and recovery. It is necessary to re-examine the economics of connecting these resources to the grid, and to explicitly value the costs and benefits of doing so.

A key challenge relates to the current recovery system for the predominantly fixed costs of transmission and distribution networks. For residential customers, most of these costs are recovered through volumetric charges per kilowatt-hour (kWh) of use.[i] As greater numbers of customers self-generate or reduce their demand for utility-provided electricity, the potential rate impact on non-DE consumers is a concern to regulators, consumer advocates and utilities. With billions of dollars of grid investments expected by utilities for transmission, smart meters, sensors and resiliency measures, a reduction or slowing of kWh's sold will require spreading cost-recovery over a smaller base.

There is disagreement about the actual impact of DE on the distribution grid: DE proponents assert that DE can reduce the need for transmission and distribution expansion; utilities assert that DE will complicate the grid and result in increased (or at least constant) capital and operational expenditures, which will need to be spread over a smaller base under a volumetric system.

While the volumetric challenge potentially can be addressed with adoption of standby or demand/access recovery charges, a challenge remains to determine how much to pay DE providers for the value of energy they supply to the grid and how much they should be charged for their use of the grid (i.e., how to value offsets to a flat access charge if they provide countervailing benefits to the distribution system?). Further understanding of the impact of DE valuation and compensation on different groups and classes of customers, particularly low-income households, must inform any recommendations.

The objectives of the Valuing Distributed Energy Roundtable include:

(1) Establish a dialogue that includes all of the relevant stakeholders,
(2) Agree on the need for a new valuation approach,
(3) Delineate the essential categories of benefits and costs to others involved in the generation and use of distributed energy, and
(4) Begin setting the stage for an inclusive process to clarify and measure these elements that can be used by regulators to determine appropriate values for each category.

The benefits and costs will ultimately vary based on the type and location of each distributed resource and the underlying physical and regulatory system. However, achieving understanding among key stakeholders about what is important to measure and value will provide a foundation for deriving efficient, fair and sustainable valuation decisions.

Framing Documents:
- ***Renewable Energy Prices in State-Level Feed-in Tariffs: Federal Law Constraints and Possible Solutions*** *– Hempling, et. al., 2010*
- ***Future of Electric Distribution*** *- De Martini, 2012*

Questions for Discussion:
1) *Is the current DE compensation framework sustainable in the face of rising DE penetration?*
2) *What outcomes will result from continuing under the current framework as DE penetration pressures grow?*

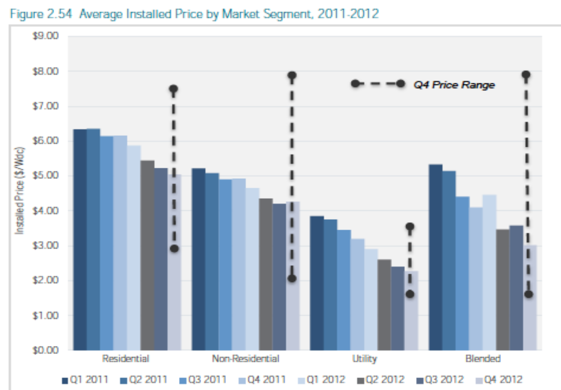
II. Defining Distributed Energy

Quick Review of DE Technology Options

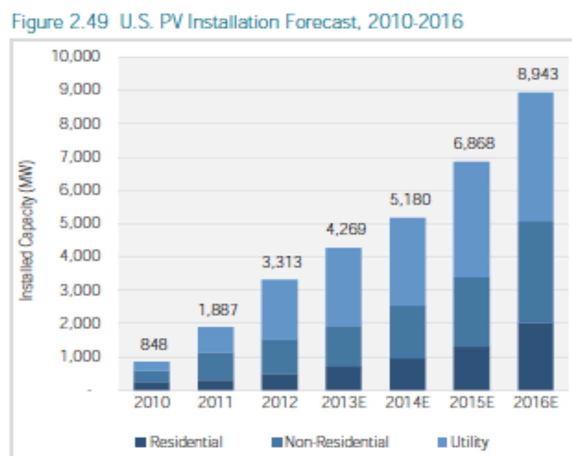
Distributed energy resources are demand and supply side resources that can be deployed on both the customer side and utility side of the meter. They include energy efficiency, distributed generation (solar power, combined heat and power, and small-scale wind, geothermal and hydro), distributed flexibility and storage (demand response, electric vehicles, thermal storage, battery storage), and distributed intelligence (communications and control technologies). [ii]

From a grid operation point of view, all of these resources share one outcome – they reduce or shift the load (including both energy and peak capacity elements) that the grid must serve to customers. This feature alone, when mapped to the current rate structures, creates economic tensions in the system that must be resolved.

Chart 01: Falling Costs of Solar PV *(Source: GTM)*



	Q1 2011	Q2 2011	Q3 2011	Q4 2011	Q1 2012	Q2 2012	Q3 2012	Q4 2012
Residential	$6.34	$6.35	$6.15	$6.16	$5.88	$5.45	$5.22	$5.04
Non-Residential	$5.22	$5.09	$4.90	$4.92	$4.65	$4.35	$4.21	$4.27
Utility	$3.85	$3.75	$3.45	$3.20	$2.90	$2.60	$2.40	$2.27
Blended	$5.33	$5.15	$4.41	$4.10	$4.46	$3.47	$3.58	$3.01



Distributed Generation (DG)

There are many kinds of distributed energy generation, including solar energy, ground source heat pumps, small wind installations, etc. However, significant growth in DG over the last decades has come from solar PV, due to its persistent price drop and public support.[iii]

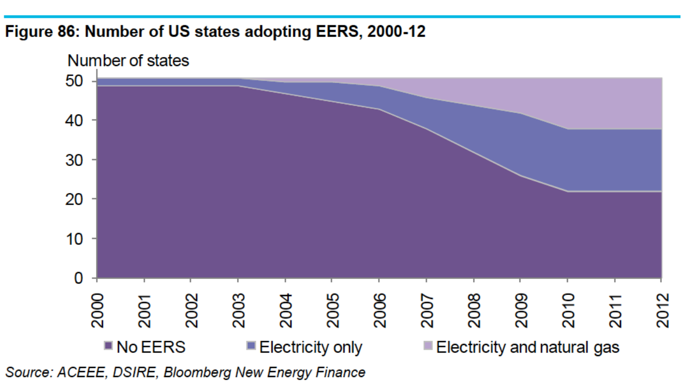
The cost of solar PV has fallen over 70% since 2008 and as Chart 01 shows, costs continue to fall. System prices have fallen from 20-33% over the last 2 years. Levelized Cost of Electricity (LCOE) reductions have been further fuelled by third-party ownership or leasing of rooftop PV systems, used by more than 50% of the residential and commercial U.S. market in 2012.[iv]

This increase in DE is expected to continue. Greentech Media estimates that annual U.S. installations of distributed solar PV will triple between 2012 and 2016, reaching 5 GigaWatts (GW) per year for commercial and residential customers.[v] Another NREL study suggests that a majority of electricity customers will find properly-financed distributed PV cheaper than grid prices by then, even in the absence of any state subsidies or carbon price.[vi]

Energy Efficiency (EE)

Energy efficiency (EE) has grown rapidly in the last 10 years and programs have been implemented in over 25 states. Chart 02 demonstrates the significant growth in one set of EE programs (Energy Efficiency Resource Standards (EERS)). The American Council for Energy Efficiency reports that EE programs have resulted in substantial consumer savings, and also suggests that further savings of up to 19% of projected energy consumption in 2030 is possible . [vii]

Chart 02: Number of US States Adopting EERS *(Source: BNEF)*



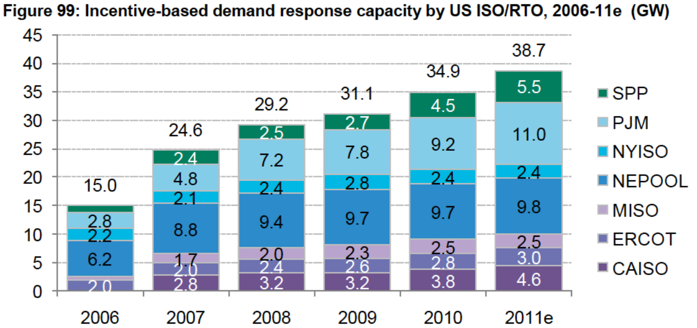
Many studies, notably McKinsey's Abatement Cost Curves, have suggested that energy efficiency has substantial and dramatic cost savings potential that could be unlocked if market barriers can be addressed.[viii]

Demand Response (DR)

A FERC survey in 2012 showed reported potential peak reduction increased by 25% due to demand response programs from 2010 to 2012.[ix] Most demand response programs at this time target industrial and commercial customers, but going forward there will be an increasing focus on residential customers. The value of demand response programs varies, but as a percentage of market prices there is a marked increase at higher loads. The National Action Plan showed further initiatives to maximize DR potential such as using DR to shift load demand curves to when renewable generators are producing power rather than dispatching quick ramping generators.[x] The degree of DR penetration is impacted by costs of hardware, level of customer incentives, and the complexity in measuring and verifying performance.

Chart 03: Rising Penetration of Demand Response *(Source: BNEF)*

Figure 99: Incentive-based demand response capacity by US ISO/RTO, 2006-11e (GW)



Source: Bloomberg New Energy Finance, data from ISOs. Note: 2011 figures are estimates. These figures include demand response activity driven by customer curtailment, as well as by behind-the-meter generation, since the ISOs do not provide this break-out.

Chart 04: DR impact of Load Curve *(Source: Brattle)*

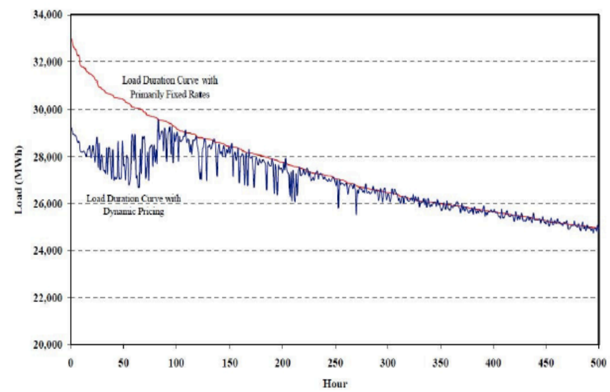


Chart 05: Projected Lithium Battery Costs *(Source: Pike)*

FIGURE 9
PROJECTED LITHIUM BATTERY COSTS (2010–2020)

Costs of lithium-ion batteries are projected to decline significantly by 2020.

Storage

The U.S. energy storage market totaled $3.06 billion in 2011 and is expected to exceed $5 billion in 2014, according to new estimates released by Climate Change Business Journal (CCBJ).[xi] Supporting this finding is a report by Pike Research that states the market for advanced batteries will roughly double each year over the next 5 years, reaching $7.6 billion in 2017.[xii] Under the most likely growth scenario given by Pike, demand for storage will grow from just over 2,500 megawatts (MW) in 2011 to more than 7,000 MW in 2014. Costs of storage are expected to decline, as seen in these cost projections for lithium batteries (Chart 05).

Chart 06: CHP Experience Curves *(Source: Stafell)*

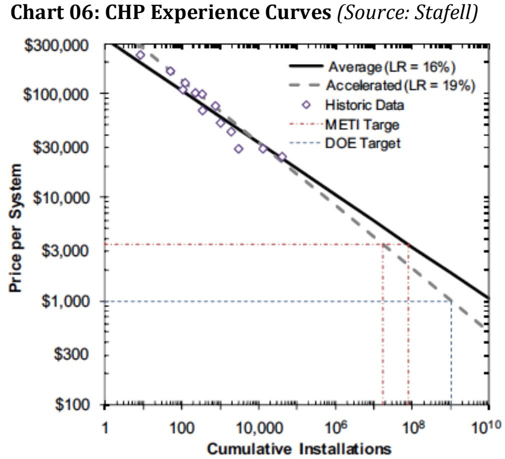


Fig. 4 – Learning curves projected forwards to 10 billion units, plotted against horizontal cost targets.

Combined Heat and Power (CHP)

Pike Research estimates that the global CHP market will enjoy a period of strong growth over the next decade, and forecasts that more than 8.5 million CHP systems, mostly small residential units, will be shipped between 2011 and 2021.[xiii] With reduced natural gas prices, CHP has become more popular in the U.S. The DOE goal is to reduce these costs to $1,000 per kW (Chart 06), which is expected to support increased demand for micro CHP products.[xiv]

III. Issues To Address In A New Pricing Mechanism

Current Valuation Methods

A Starting Point: Public Utilities Regulatory Policy Act 1978 (PURPA)

PURPA, enacted in 1978 and updated in 1992 and 2005, established access by independent power producers' (IPPs) generation to electricity markets. It required utilities to purchase power from Qualifying Facilities (QFs) at their incremental or avoided costs. PURPA has less influence in states that are part of organized competitive markets, where utilities have achieved exemptions from certain provisions of PURPA by demonstrating that IPPs have access to competitive markets through a Regional Transmission Organization (RTO). However, PURPA's experience with a cost based calculation is useful in evaluating options for DE pricing. Many emerging attempts to properly price DE use PURPA's legal foundation, including California's reverse auction mechanism (discussed later).

Under PURPA, states have discretion as to how to calculate their avoided cost. Generally including both Energy and Capacity values, the methods of calculation can be broadly grouped into 5 classifications [xv]:

- **Proxy Unit Methodology** which assumes that the utility is avoiding building a proxy generating unit itself by utilizing the QF's power. The fixed costs of this hypothetical proxy unit set the avoided capacity cost and the variable costs set the energy payment.
- **Peaker Unit Methodology** which assumes that a OF allows the utility to avoid paying for a marginal generating unit on its system, usually a combustion turbine. The capacity payment is based on the fixed costs of the utility's least cost peaker unit and the energy payments are forecast payments for a peaker unit over the lifetime of the contract.
- **Differential Revenue Requirement** which calculates the difference in cost for a utility with and without the QF contribution to generating capacity.
- **Market Based Pricing**, which is allowed as an exemption under PURPA. QFs with access to competitive markets receive energy and capacity payments at market rates.
- **Competitive Bidding**, which allows states to utilize open**,** bidding processes. The winning bids are regarded as equivalent to the utility's avoided cost.

Table 01: Challenges of Different Costing Methodologies

Method	Challenges
Proxy Unit Methodology	May overstate costs Heavily depends on which proxy selected
Peaker Unit Methodology	Not always sufficient to finance QFs
Differential Revenue Requirement calculation	Not transparent; complex Short term – always assumes QF is marginal resource
Market Based Pricing	Not always high enough to incentivize QF development
Competitive Bidding	Complicated for QFs and rates not high enough to incentivize QF development

States can consider other factors when calculating the avoided costs. These are:

- Dispatchability and minimum availability as a precondition to capacity payments
- Line loss and avoided transmission costs
- Externalities and environmental cost adders
- Long-term levelized contract rates versus varying rates
- REC availability
- Resource differentiation

Location

Precisely where the DE intervention occurs will determine a lot about the value of each component of the cost-benefit analysis. It will influence 1) the value of energy displaced, 2) capacity and reserve requirements, 3) many of the factors used to determine congestion or losses in the T&D infrastructure, and 4) the jurisdictional authority issues to include externalities in the pricing mechanism.

Market Pricing/Competitive Bidding Models vs. Constructed (Proxy) Price Models

In developing a valuation methodology for DE, it is necessary to understand the underlying regulatory and market structure. PURPA (and its amendments) allows for the establishment of pricing or tariffs using both a competitive bidding and a structured proxy value methodology. In jurisdictions that do not have organized competitive markets, pricing mechanism options include constructed price models or tariffs and requests for proposals (RFPs) for long term procurement (which can be competitively bid). In organized markets (ISOs and RTOs), competitive markets set wholesale energy, capacity and ancillary services prices. If regulators determine to make adjustments to market-based prices for DE to account for externalities or specific pecuniary costs and benefits, they must determine how to set pricing or quantity variables.

Short-term Transactions versus Long-term Contracts

Regardless of whether market-based or proxy pricing is used, it is still necessary to determine if that pricing will be set on a short-term basis or a long-term basis. Some examples of DE pricing mechanisms being used today (Austin Energy Value of Solar Tariff (VOST)) are a short-term mechanism with a price that fluctuates on an annual basis, while others (Market Price Referent in California) establish a price over 10 to 25 years.

Through the impact on revenue certainty, the length for which payments are established heavily influence a developer's ability to get financing, and therefore eventual market uptake – a situation that has led to some PUCs (including Georgia) to determine that long term pricing is the only feasible method to add distributed energy. Any pricing mechanism has to be clear about the length of time over which prices are established.

Sensitivity to Penetration Levels

Every cost and value driver will change over various levels of penetration. Some are high at the early stages of penetration and fall later – others do the reverse. A dynamic pricing mechanism understands that the correct metric relates to the current level of penetration, but system planning will require an understanding of how these elements change as penetration levels rise.

Uncertainty and Variability

Some DE sources, particularly solar, create uncertainty challenges that must be accounted for in valuation. In the case of solar, during cloud cover systems must be backed up by storage, another on-site generator or by the grid. This issue becomes more significant as penetration increases. A solar array paired with storage can reduce variability and provide value to both the hosting customer and the grid.

Pecuniary vs. Non-Pecuniary Costs and Benefits

Not all costs and benefits are the same. Some are clearly intrinsic to the transaction, such as the energy and capacity value of any new source (or displacement of load), and are accounted for under current avoided cost methodologies or the organized markets that establish them.

Other costs and benefits have to be distinguished as being intrinsic to the intervention or external to it. Pecuniary elements are those that have direct cost or benefit to someone who is party to the electricity transaction (ratepayers, grid operators, DE providers etc. both now and in the future). Non-pecuniary elements, sometimes also referred to as externalities, refer to costs or benefits to those outside the transaction (the environment, society, etc.) Greater transparency can be achieved by distinguishing between pecuniary and non-pecuniary costs and benefits that arise from DE additions to the electricity system.

Jurisdiction

The question of the whether there should be a more significant federal role (at least to foster coordination at the regional grid level) arises due to a number of DE impacts: the potential of DE to help or exacerbate load constraints in regional markets; the possibility that deployment of variable DE might impact reliability (positively or negatively) regionally; and the possibility that decisions by one state to increase the value of DE by including a number of non-pecuniary factors in its avoided cost accounting could (positively or negatively) impact customers in other states through interconnection costs. Additionally, while states are implementing DG programs, DG is strictly speaking part of the wholesale energy market (which falls within federal jurisdiction). Many states manage this jurisdictional issue by having DG customers credited for their power on bills, so that they are not being paid directly for energy generation. Where to draw the state-federal line remains an open question.

Framing Documents:

- ***Reviving PURPA's Purpose*** *– Carolyn Elefant, 2012*

Questions for Discussion:

1) *Which DE interventions (DG, EE, DR, Storage) should use short-term pricing mechanisms and which should use long-term ones?*
2) *Should pricing mechanisms be constructed with only LT or ST elements, i.e. avoiding mixing?*
3) *Is it more economically efficient that (a) suppliers be allowed to provide any volume below the proxy price (i.e. MPR), or (b) volume be capped and then bidding established to minimize the price?*
4) *Does the retail/wholesale line prevent states from being able to implement certain pricing/payment schemes?*
5) *How much latitude should states have around avoided cost valuations? Should states be able to make these valuations independently, and/or should there be guidelines/standardized factors (issued by the reliability councils or FERC)?*

IV. Building up a Valuation Model

Part 1 – Choosing the Right Energy Value

Establishing a value for the energy benefit of a load reduction is fairly straightforward**.** It is typically valued at the value of the next best alternative for energy being fed into the grid at a specific place and time, including variable fuel and operations and maintenance and possibly capital charges for the physical plant in the case of longer-term pricing mechanisms.

This differs somewhat based on whether short-term energy value or long-term values are used. Short-term energy values are calculated as the marginal cost of operation, including variable cost of fuel and O&M, while long-term energy cost relies on average cost and must include all of the costs, both fixed and variable.

Some studies argue that the reduction in utilization of existing generators does not create a one-to-one reduction in fuel use or O&M. The contention is that more variable generation causes systems to be less efficient. More work has to be done to determine the actual marginal cost savings for reduction in generation – particularly over the whole electricity system.

Table 02 : Energy Values across DE Options (Source: Bradford, Browne, et. al.)

Technology	Calculation of the energy Q	Value of energy P	Economic Rationale	Sensitivity (per unit) to penetration
Renewable Energy (Solar/Wind)	Energy generated or displaced by the QF (Less: any consumed in filling storage)	Long term view: FIT, RAM, etc.	**HIGH** - After initial investment, the variable costs are zero (no fuel costs). Supply is on and "as available" basis.	**FLAT (HEDGED) –** The intrinsic value of Energy from RE CG may rise and fall with prices, but consistently delivers volume
Demand Response		Short term view: LMP	**HIGH** - The Energy value of DR is very short-term – responds to price signals.	**FALLS -** A high penetration and use will reduce the LMP as arbitrage sets in.
Energy efficiency		Long term view: ESA, Ratebase	**HIGH to LOW** - Efficiency effects are indiscriminate and price-insensitive, so fall equally in high-and low-value times	**FALLS -** With an increasing energy efficiency penetration, the investment costs will go up and reduce margin
Storage		Short term view: LMP	**HIGH** - The Energy value of storage is short-term (buy off-peak, sell at peak time) and responds to price signals	**FALLS -** The gap of LMP between peak and off-peak hours should decrease with an increase penetration of storage (less variability)
Combined Heat and Power (CHP)		Short term view: LMP	**HIGH** - CHP plants behave like DG with sunk capital costs. However, fuel price risk over the life of the asset require more frequent pricing mechanisms.	**FLAT (UNHEDGED) –** CHP capital sensitivity to penetration should be low, but unhedged variable fuel prices are a substantial risk factor.

QF = Qualified Facility RAM = Reverse Auction Mechanism, LMP = Locational Marginal Price, FiT = Feed-in Tariff, ESA = Energy Service Agreement

Questions for Discussion:

1) *Does the table above accurately reflect the volume and price considerations for calculating energy value across DE options?*
2) *How should we think about short-term energy values vs. long-term energy values across these technologies?*

Part 2 – Choosing the Right Capacity Value

Capacity markets exist to ensure that the electricity system has adequate reserve requirements at a competitive market price.[xvi] For the DE interventions that rely on an intermittent resource - specifically distributed generation from solar, etc. - there is a question about how much capacity should be valued. Values between 0% and 100% have been proposed, but some more rigorous attempts have been made including Effective Load Carrying Capacity (ELCC) and Loss of Load Potential (LOLP).

The Energy Policy Act of 2005 required that DOE, in consultation with the FERC, conduct a study of the potential benefits of cogeneration and small power production. DOE reported that distributed generation could yield improvements of 5% to 22% in certain reliability indices depending on penetration, and that improvements in reliability could occur even if DG was not 100% reliable itself.[xvii] The DOE also sponsored a 2003 study that found an avoided capacity value for T&D investment of up to one-third the marginal cost of the distributed generation equipment under certain conditions. [xviii]

Table 03: Capacity Values across DE Options (Source: Bradford, Browne et al.)

Technology	Calculation of capacity (Q)	Avoided costs (P)	Economic Rationale	Sensitivity (per unit) to Penetration
Renewable Energy (Solar/Wind)	Local analysis of ELCC	cost of a proxy unit (i.e. CCGT)	**LOW** – Fundamentally intermittent. Local ELCC must represent true predictability of RE. Need long term pricing to secure investments.	**RISES** – As more intermittent renewables are added, they create a natural diversification
Demand Response	Capacity available at the peak	cost of a Peak plant (CT)	**HIGH** - Small capital investment, fast market penetration (PJM) Capacity available only for a short time: >> similar to a peak generation plant	**FALLS** – Capacity value falls quickly as reserve margins rise
Energy efficiency	Capacity unused after investement	cost of a proxy unit (CT)	**MEDIUM** - Capital intensive. Consumption of capacity reduced not only for peak hours	**FLAT** – Will continue to deliver value over wide range of penetration
Storage	Capacity of the plant	cost of a Peak plant (CT)	**HIGH** - Capital intensive. Need a security (safe long-term contract) for the investment.	**FALLS** – When used for power and capacity, should fall quickly with rising reserve margin.
Combined Heat and Power (CHP)	Capacity of the plant	cost of a proxy unit (i.e. CCGT)	**HIGH** – Flexible, predictable: almost like a conventional plant. Contract: have to run on peak hours. Will also run off-peak. This justifies the use of a proxy, but requires an agreement on the dispatchability	**FLAT** – Not, by itself, expected to change capacity value

ELCC = Electric Load Carrying Capacity CT = Combustion Turbine, CCGT = Combined Cycle Gas Turbine, FiT = Feed-in Tariff, ESA = Energy Service Agreement

Framing Documents:
- ***A Capacity Market that Makes Sense*** - *Cramton and Stoft, 2005*

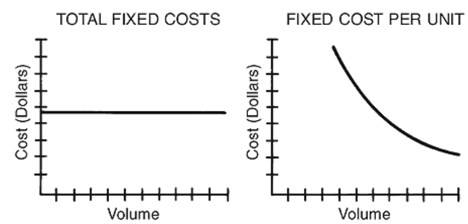
Questions for Discussion:
1) *Does the table above accurately reflect the volume and price considerations for calculating Capacity Value across DE options?*
2) *Under which circumstances and to what degree should capacity value be applied at all to non-dispatchable DG?*
3) *What is the expected impact of storage and transmission on DE capacity?*

Part 3 – What Are The Pecuniary Costs Borne By Others?

These costs can result in shifting of costs or risks, including reliability, system planning and regulatory recovery risk-shifting from DE providers/customers to the distribution utility and/or other customers.

I. Loss Of Revenue For Fixed Charge Coverage (All, CONSTANT)

Chart 07: Rising Fixed Charges

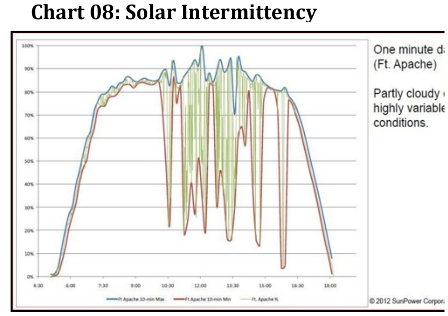


Under a regulatory system where fixed costs are spread over the average per-customer kWh sales for residential customers, the charge per kWh will increase as customers reduce their use of electricity supplied by a utility (assuming no offsetting reductions in grid operation costs). With the exception of DE generators that fully separate or "island" from the grid, most DE generators use the grid for interim storage and backup supply, and receive benefit from the grid being maintained and operated. They essentially receive an "option" to use the grid when needed. By reducing the kWhs consumed, DE generators may shift costs of maintaining and operating the grid to other consumers who do not self-generate a portion of their electricity, or to the utility if it is unable to raise its rates. In addition to operational and capital expenses, the utility may also have to recover societal benefits charges, and other on-bill assessments, across a smaller base of customers and kWhs. This cost may decline over time, if reduction in demand allows a downsizing of the bulk system.

II. Administrative Charges (All, Starts HIGH – then FALLS)

As utility customers implement DE systems, the utility will incur administrative expenses to interconnect facilities, change billing processes and seek revised rate recovery. There may also be costs for scheduling, integration, load forecasting, and system planning, control and dispatch. Administering a larger number of smaller distributed systems could cost more than administering a small number of utility-scale systems. There are also costs associated with maintaining consumer protections.

Chart 08: Solar Intermittency



III. Firming Expense For Intermittent Renewables (DG, Starts LOW – then RISES)

In the case of intermittent renewables, there will likely be additional operating costs for system support capabilities to maintain reliability, including operating reserves, regulation and control of power output in relation to demand ("load following"). For example, PV generation can ramp up and down quickly due to cloud impacts, malfunction of inverters, and operating reserves called upon to pick up the load. Variability-induced costs have not been well quantified to date but can be mitigated to some degree by geographic and resource diversity, aggregation of multiple inverters and storage.[xix] The ability to forecast cloud cover and manage back-up generation to compensate is also a key variable in determining firming expense.

IV. Change In Fixed Asset Lifetime And Performance (DG, Starts LOW – then RISES)

As DE penetration increases, problems can be created by two-way flow of power on distribution systems. Upgrades may be needed to operate the system without overloading circuits or jeopardizing safety. These costs can include local distribution infrastructure costs to enable individual DG installations, firming costs for intermittent resources, cyber security vulnerability, restoration, and system-wide grid modernization costs. As penetration increases, system upgrades in protection and control systems may be required, along with installation of power electronics devices. A Navigant study on Nevada Energy's system relating to PV integration concluded that these costs were small or negligible, but the costs will vary by system, penetration level and location. [xx]

Framing Documents:

- ***Managing Large-Scale Penetration of Intermittent Renewables*** *- MITEI, 2011*
- ***The Cost of Standing By*** *- Tempchin, 2013*

Questions for Discussion:

1) Are these the major categories of pecuniary costs that should be considered?
2) If these were adequately compensated, would the burden on non-participating customers be eliminated?
3) What pecuniary savings should be considered?

Part 4 – What Are The Pecuniary Benefits Received By Others?

These costs can result in the receipt of price or risk reduction benefits by others than those who create them when they install a DE solution.

I. Transmission & Distribution investment offsets (All, Starts LOW, then RISES)

DE proponents contend that the use of distributed solutions, particularly on the customer site, reduces the amount of investment that traditional utilities must make in transmission and distribution. The degree of impact may vary over time, with the benefit increasing as investment plans are modified. Utilities using the proper pricing and costing methodology may be able to proactively determine economic "targets of opportunity" for places where DE is a cheaper investment than T&D.

Chart 09: Calculating T&D Offsets *(Source: DOE)*

$$\text{Deferral cost} = \frac{\text{Avoided upgrade cost} \times \text{Fixed Charge Rate}}{\text{DG capacity required}}$$

II. Line Losses and Congestion (All, CONSTANT)

The DOE/FERC study of 2007 also estimated a reduction of line losses of 19% for each 10% that DG reduces current load. These benefits should extend to all technologies that function as load reduction. Proponents have suggested a number of other system function improvements from DE as well. Depending on the duration of the power output, DG could possibly improve power quality, mitigate outages and regulate voltage – all of which could have benefit to grid operators and ratepayers.

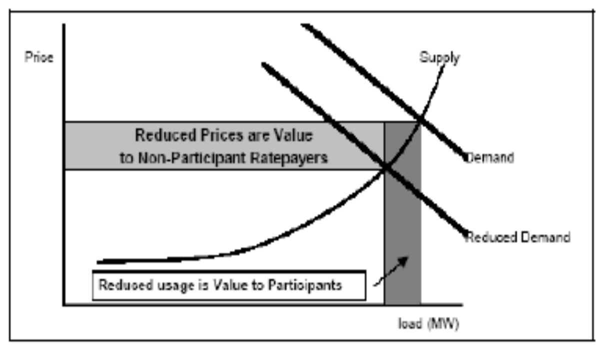
III. Merit Order Effect (All, Starts HIGH, then FALLS)

Reducing the load on the electricity system reduces the energy required for that particular customer, and also reduces the energy and capacity clearing prices that all customers have to pay in the wholesale market. While small on an individual rate basis, the aggregate effects (particularly at early levels of penetration) over all customers can be significant.

This effect starts high, but diminishes as peak shaving occurs. According to the LBNL, "high PV penetration levels reduce the value of bill savings under most combinations of rate options and compensation mechanisms evaluated." [xxi]

Chart 10: Merit Order Effect *(Source: DOE)*

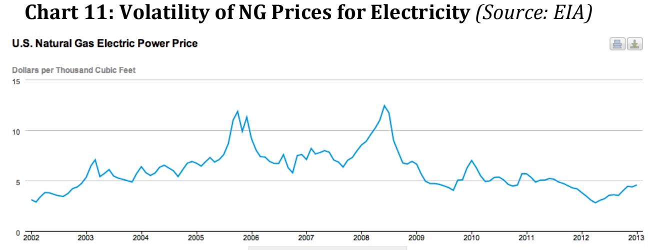
Figure 3-4. Market Price and Value of Load Reduction



IV. Fuel price hedge (All, Starts HIGH, then FALLS)

Many, but not all, DE technologies have the advantage of consuming zero fuel. Once the systems are installed, there is a high degree of visibility on the long-term price. Conversely, most fossil fuel generators (particularly those using natural gas) have an underlying fuel price volatility that is borne by customers beyond the period for which forward markets exist (usually less than five years). Recent developments in the natural gas market have driven prices down, but the long-term forecast for gas and concerns about volatility mean this hedge still has value.

Chart 11: Volatility of NG Prices for Electricity *(Source: EIA)*



Framing Documents:

- ***The Potential Benefits Of Distributed Generation And Rate-Related Issues That May Impede Their Expansion*** *– FERC/ DOE, 2007*
- ***Maximizing the Benefits of Distributed Photovoltaic*** **-** *Hoke and Komor, 2012*

Questions for Discussion:

1) *Are these the major categories of pecuniary benefits that should be considered?*
2) *If these were adequately compensated, would the benefits that DE interventions bring to ratepayers be fully compensated?*

Part 5 – What Non-Pecuniary Costs and Benefits Exist?

Non-pecuniary benefits and costs, or externalities, of DE interventions are considered important by many proponents, as well as by many jurisdictions. Separately delineating and accounting for these costs out is not a statement on their importance. Rather, it is an acknowledgment of how they need to be considered in any pricing mechanism differently than those that are intrinsically part of the pricing transaction.

I. Environmental Benefits

Depending on the type of distributed energy, there can be local environmental benefits from displacing fossil-fueled generation with distributed solar energy, natural gas fired CHP, demand response and energy efficiency. Reductions in emissions of pollutants, including SOx and NOx, provide public health benefits. Full lifecycle benefits might include mining and extraction, transport and loss in the fuels supply chain, water and land use implications, waste and decommissioning, etc. This analysis will, obviously, vary greatly by location and technology.

II. Greenhouse Gas Abatement Benefit and Costs

Depending on the type of distributed energy resource and the state greenhouse gas regulatory regime, a carbon dioxide abatement benefit or cost could be assigned a monetary value. In states that participate in a cap and trade system, this value can be determined by the price of local or regional carbon credits. Policymakers could add or subtract this value from the DE compensation rate depending on the resource, presuming it isn't already picked up by a carbon mechanism elsewhere in the supply chain. It will be important to determine how any existing infrastructure or jurisdiction is impacted by carbon mechanisms already and whether those are efficient before levying additional charges.

III. Energy Security Benefits

The availability of micro-grids and other DR sources that can be islanded in times of widespread outages could provide public safety, health and economic benefits. For example, if critical hospital, public safety, governmental and educational institutions had access to alternative, distributed energy supplies, there would be a public benefit of some compensable value. These resources could be provided by independent DE providers or by utilities.

IV. Public Good Value and Provider of Last Resort

Society benefits from having a grid through which all citizens can receive electricity. Such interconnectivity supports the provision of basic human needs, as well as economic activity. The grid also adds value as a technology for enhancing substitution of resources (i.e., the current substitution of natural-gas fueled resources). Policymakers could make an adjustment to DE compensation rates or access charges to ensure that the public good of a ubiquitous electricity grid is maintained.

V. Local Economic and Job Creation Differentials

Arguments are often made that the use of local labor and capital can create economic impacts. Proponents of all aspects of the electricity system use these claims in support of their preferred technology. A full systems understanding of the job creation and economic benefit of various pathways versus the alternatives will help to determine if there are any differential job or income benefits from one set of technologies or another.

Framing Documents:
- ***Quantifying the Cost of High PV Penetration.*** *Hoff, et. al., 2010*
- ***Austin Energy Study,*** *Clean Power Research, 2006*

Questions for Discussion:
1) *Is there any way in which these externalities should be treated differently in a pricing mechanism and a director pecuniary cost or benefit?*
2) *Are there other externalities that must be considered omitted here?*

A Straw Man Recommendation For New Avoided Cost Determination Methodology

Mandatory – (<u>**E+C-Co+Be**</u>) A new methodology for Avoided Cost Calculus that incorporates each of the energy, capacity, pecuniary costs, and pecuniary benefits.

This calculus should be determined on a <u>long-term</u> basis for assets naturally suited to providing long-term energy services such as DG, EE, and long-term storage for energy services, and LMP-based for those that are dispatched based on short term market signals (DR and short-term storage for ancillary services), or have substantial unhedged cost components such as CHP.

1. Energy savings: benefits from DE's offset of wholesale energy purchases. (E)
2. Generation capacity savings (C)
3. Pecuniary Costs (Co)
   - Including the 4 costs established above
4. Pecuniary Benefits (Be)
   - Including the 4 benefits established above
5. Environmental externalities (optional) (Ext)

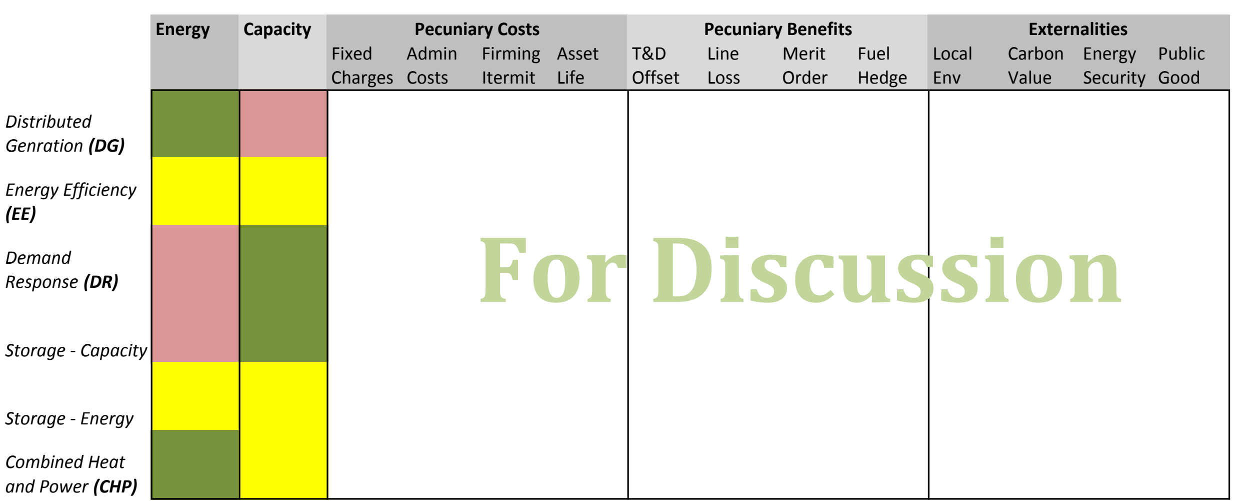
<u>**New Avoided Cost Calculus = E+C-Co+Be+Ext**</u>

Optional (<u>**+Ext**</u>)– States have the right to include externalities for environmental benefits, security, local economic benefit, etc. in the price calculus, but these should be explicitly authorized and determined.

The recommendation is that the tenor of these also matches the tenor of the underlying interventions - i.e. short-term for DR and storage used in ancillary services, long-term in the cases of DG, EE, and long-term storage for energy services.

Summary Review: Differences Among DG, EE, Demand Response, Storage for Each of the Cost and Benefit Characteristics

Chart 12: Possible Matrix for Discussion of costs and Benefits *(Green - High, Yellow - Medium, Red - Low)*



<u>Questions for Discussion:</u>
1) *Should pecuniary and non-pecuniary costs be handled distinctly when incorporated into an appropriate price mechanism?*
2) *When examined across all of the different technologies does this still seem like the correct combination of pecuniary costs, pecuniary benefits, and externalities?*

V. Examples Of How This Looks In Practice

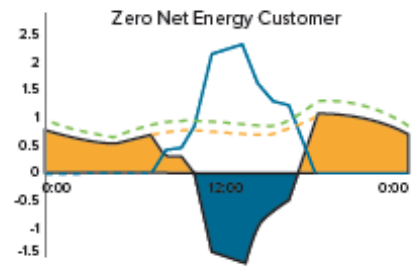
Existing Mechanisms

A number of pricing mechanisms are in use today. Largely, they include some measure of energy and capacity, as well as a few other components that were politically feasible in the authorizing jurisdiction at the time they were established. None is comprehensive.

Net Metering (DG – Short-term, Average Cost, Full Retail Rate + REC)

Net Metering (NM) allows for the times that DG customers are generating more electricity than they are consuming to put that electricity back into the grid. In effect, they are compensated at a full retail rate payment at whatever the then-prevailing variable rate for electricity is.

Chart 13: Net Metering *(Source: RMI)*



The problem is that this implicit price makes no attempt to quantify pecuniary benefits or costs of DG. Many net metering rules reimburse customers at the retail rate, which neither reflects the true cost to serve these customers nor the value that solar provides. As such, this "rough justice" has created uncertainty and tension between grid operators and DG customers, whereby both believe they are providing benefits to the other without adequate compensation.

Also, in cases where renewable energy credits (RECs) or other benefits payments exist, the customer typically retains them, as well. For the purpose of fitting it into a pricing framework, these would be added to the "full compensation" calculus on behalf of the DG intervention.

Market Price Referent (DG – Long-term, Average Cost, Energy only)

Chart 14: MPR Pricing, 2011 *(Source: CPUC)*

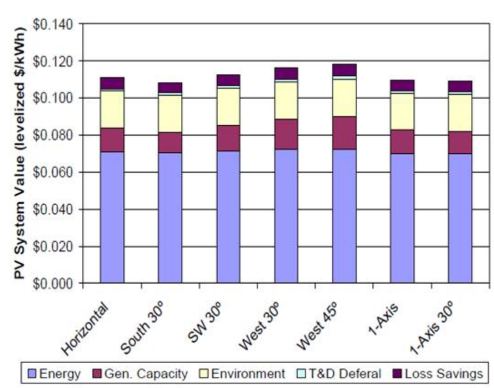
Adopted 2011 Market Price Referents[1] (Nominal - dollars/kWh)				
Contract Start Date	10-Year	15-Year	20-Year	25-Year
2012	0.07688	0.08353	0.08956	0.09274
2013	0.08103	0.08775	0.09375	0.09695
2014	0.08454	0.09151	0.09756	0.10081
2015	0.08804	0.09520	0.10132	0.10464
2016	0.09156	0.09883	0.10509	0.10848
2017	0.09488	0.10223	0.10859	0.11206
2018	0.09831	0.10570	0.11218	0.11572
2019	0.10186	0.10928	0.11587	0.11946
2020	0.10550	0.11296	0.11965	0.12326

The **Market Price Referent (MPR)**, according to the California Public Utilities Commission (CPUC):

- The MPR represents the levelized price, calculated using a cash flow modeling approach, at which the proxy CCGT revenues exactly equal the expected proxy CCGT costs on a net-present value (NPV) basis.
- The fixed and variable components of the MPR are calculated iteratively (using the MS-Excel goal seek function) and summed to produce all-in MPR price.
- The MPR Model inputs include installed capital costs, fixed and variable operations and maintenance costs, natural gas fuel costs, cost of capital, and environmental permitting and compliance costs.

Austin Energy VOST (DG – Short-term, Average Cost, Energy Plus Benefits)

Chart 15: Austin Energy VOST *(Source: CPR)*



(from the Clean Power Research analysis of the value of solar)

Austin Energy adopted a **Value of Solar Tariff (VOST)** program in 2012, which established a short-term pricing mechanism to compensate solar customers for a collection of benefits that solar provides to the grid including[xxii]:

- Avoided fuel costs, which are valued at the marginal costs of the displaced energy
- Avoided capital cost of installing new power generation due to the added capacity of the solar PV system
- Avoided transmission and distribution expenses
- Line loss savings
- Fuel price hedge value
- Environmental benefits

LMP calculus (DR – Short-term, Marginal Cost, Energy and Capacity Plus some Pecuniary Benefits)

Locational Marginal Price (LMP) is determined by looking at wholesale market prices at individual nodes (where available). Because of this construction, it implicitly contains three components:

- Energy (MC)- Cost to serve the next increment of demand at the specific location, or node, that can be produced from the least expensive (and available) generating unit
- Congestion - Calculated at a node as the difference between the energy component of the price and the cost of providing the additional, more expensive, energy that can be delivered at that location (can be negative in cases where generation > demand)
- Losses - Location price is adjusted to account for the marginal cost of transmission loss

Demand response providers currently get paid for the capacity they supply to organized markets where capacity markets exist. In 2006, PJM became one of the first RTOs to allow DR and storage to bid into capacity, energy and ancillary services markets and is currently adjusting rules to grow DR participation.[xxiii] While proper pricing mechanisms has been heavily debated in academic literature and in various state and federal proceedings, the current ruling is that they should get compensated at the LMP. [xxiv]

Integrated Resource Plans (EE and DG, Long-term, Costs + ROE)

It is also possible to look at the aggregate cost and benefit impacts of DE penetration through the use of an Integrated Resource Plan (IRP). By looking at the generation and transmission infrastructure in place, then trying to model various scenarios over time, it is possible to establish a differential between baseline scenarios and modified plans – which allows for the determination

While widely used in the industry, very few IRPs currently include solar in their available suite of technology options, and only two have included DG – Arizona Public Service (APS) and Los Angeles (LADWP).[xxv] Many other IRPs include EE, but in both of these DG cases, it is unclear that all of the cost and benefit elements identified in this report are adequate or consistently measured.

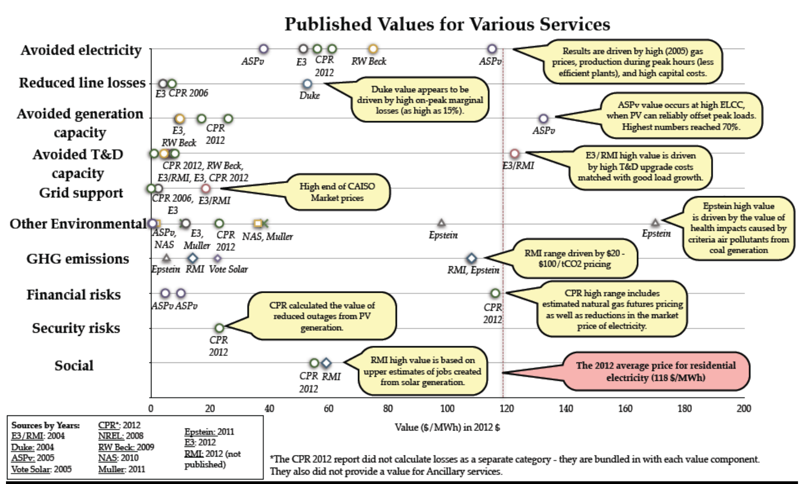
Attempts To Construct Costs and Benefits

Many attempts have been made to construct comprehensive cost and benefits metrics. Over two-dozen studies have quantified some subset of these, but all of these suffer from some real or perceived bias in their construction.

Potential errors include:

1. Only focusing on the benefits or the costs, without integrating them into a comprehensive analysis
2. Determining a value without proper understanding about how the various local conditions might impact the calculus
3. Lacking a clear understanding about how the costs or benefits would change over time or penetration levels
4. Mixing short-term and long-term pricing variables into a single calculus

Chart 16: Sample Chart of Published Benefits Values *(Source: RMI)*



Clearly more work must be done, and it must be done collaboratively among all of the stakeholder groups.

Questions for Discussion:

1) *Are any of the methods above sufficient to correct the price for DE under some circumstances?*
2) *Which aspects of the above attempts are most and least helpful from various perspectives?*
3) *What is the best forum to move forward on establishing "best practices" for constructing DE pricing tools?*

VI. Conclusion

The prospect of a more distributed electricity network offers promise on many levels -- economic, environmental, technological, and sociological. Just as we saw with the advent of computing, the internet, and various telephony services, the emergence of new classes of energy production and efficiency technology and business processes will provide individuals and businesses with access to new options and more control over their energy use. In many cases, this will drive increasing pools of value to be captured as production unleashes improved productivity.

However, unless this can be efficiently measured, effectively regulated, and fairly allocated, this transition can be disruptive in negative ways, too -- potentially undermining access and reliability of an electricity grid that serves as a critical social and economic foundation. Conversely, not addressing this situation also has risks. Successive short-term fixes to the grid, absent a long-term view of potential different system configurations, threatens costly long-term outcomes.

This paper and the ensuing policy roundtable provide a starting point for re-examining the economics of connecting distributed resources to the grid, explicitly valuing the costs and benefits of doing so, and bringing together the range of stakeholders who will be essential to enabling a successful transition.

By coming together and agreeing on a framework for regulatory and policy discourse, stakeholders can mitigate the costs (and maximize the value) of integrating distributive resources. By planning proactively, facilitating fair compensation and providing effective incentives for investing in and maintaining the distribution network, there is opportunity to create real economic value that can be shared by consumers, DE providers, and distribution utilities.

i Managing Large-scale Penetration of Renewables, MIT Energy Initiative Symposium, April 2011

ii See RMI, "Exploring the Costs and Values of Distributed Energy Resources, December 2012

iii Bradford, 2012

iv See Navigant Research, Renewable Distributed Generation, Distributed Solar Photovoltaics, Small Wind Power, and Stationary Fuel Cells: Demand Drivers and Barriers, Technology Issues, Competitive Landscape, and Global Market Forecasts
See: http://www.navigantresearch.com/blog/leasing-drives-u-s-distributed-solar-market

v See GTM Research, Q4, 2013 US PV Market Research Report

vi See Margolis, et al., Evaluating the Limits of Solar Photovoltaics (PVs) in traditional Electric Power Systems, Energy Policy 35 (2007) 2852–2861

vii See Vaidyanathan et al, Overcoming Market Barriers and Using Market Forces to Advance Energy Efficiency, March 18th 2013. See - http://aceee.org/research-report/e136

viii See McKinsey study, Bressand et al , Wasted energy: How the US can reach its energy productivity potential. Available at: http://www.mckinsey.com/insights/energy_resources_materials/how_us_can_reach_its_energy_potential

ix FERC, Assessment of Demand Response and Advance Metering, See http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0CDIQFjAA&url=http%3A%2F%2Fwww.ferc.gov%2Flegal%2Fstaff-reports%2F12-20-12-demand-response.pdf&ei=c9BlUbTUO4WD0QGviYCwBg&usg=AFQjCNENkXc6W67ClJcTOA9Q_xDxqMxhuA&bvm=bv.44990110,d.dmQ

x See FERC National Action Plan on Demand Response, June 17th 2010
available at
http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0CEoQFjAA&url=http%3A%2F%2Fwww.ferc.gov%2Flegal%2Fstaff-reports%2F06-17-10-demand-response.pdf&ei=j-BlUemdBOm40gHxsIGgBQ&usg=AFQjCNF3vZCh0xl1tl-yNuO1gT5lAPDc6w&sig2=yRcJZIt6Z9hofe-90lzVHQ&bvm=bv.45107431,d.dmQ

xi See http://www.climatechangebusiness.com/U.S._Energy_Storage_Market_Forecast_to_Exceed

xii See http://www.navigantresearch.com/newsroom/advanced-batteries-for-energy-storage-will-represent-a-market-of-nearly-30-billion-by-2022

xiii See Pike Research, Combined Heat and Power, Fuel Cell, Engine, and Turbine Technologies for Cogeneration in Residential, Commercial, Institutional, and Industrial Applications. http://www.navigantresearch.com/newsroom/combined-heat-and-power-unit-shipments-to-total-8-5-million-by-2020.

xiv See Stafell et Al, The cost of domestic fuel cell micro-CHP systems , International Journal of Hydrogen Efficiency, 38 2013 (1088 to 1102) (Stafell)

xv Adapted from Elefant, 2012, Reviving PURPA's purpose: The Limits of Existing State Avoided Cost Ratemaking Methodologies in Supporting Alternative Energy Development and A Proposed Path for Reform

xvi See Cramton and Stoft, Why we need to stick with Uniform Price Auctions in Electricity Markets [Electricity Journal], Jan./Feb. 2007, Vol. 20, Issue 1 1040-6190

xvii See Brown and Freeman, A Reliability Improvement Roadmap Based on a Predictive Model and Extrapolation Technique, 2001 *quoted in* FERC, The Potential Benefits of Distributed Generation and Rate-Related Issues that may Impede their Expansion, 2007, A study pursuant to section 1817 of the Energy Policy Act of 2005.

xviii Hadley et al, Quantitative Assessment of Distributed Energy Resource Benefits, May 2003 available at: http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0CDIQFjAA&url=http%3A%2F%2Fwww.ornl.gov%2F~webworks%2Fcppr%2Fy2001%2Frpt%2F116227.pdf&ei=pgRmUYbhG4aB0QH8mIGAAg&usg=AFQjCNGJmsEDZptQuTR1CxJumMob2H5rjg&sig2=T0euQhxmDaQ-3gU5zSJTuQ&bvm=bv.45107431,d.dmQ

xix See Hoke and Komar, Maximizing the Benefits of Distributed Photovoltaics, April 2012

xx See Navigant, Photovoltaics Value Analysis

xxi Electricity Bill Savings from Residential Photovoltaic Systems: Sensitivities to Changes in Future Electricity Market Conditions, LBNL,2013 -

xxii http://www.austinenergy.com/energy%20efficiency/Programs/Rebates/Solar%20Rebates/proposedValueSolarRate.pdf
http://www.greentechmedia.com/articles/read/austin-energys-value-of-solar-tariff-could-it-work-anywhere-else
http://www.greentechmedia.com/articles/read/can-a-value-of-solar-tariff-replace-net-energy-metering

xxiii See RMI, Dec 2012, p. 11

xxiv FERC, 2012

xxv See Mills and Wiser, An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes, LBNL-5933E, December 2012