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.

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.

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.

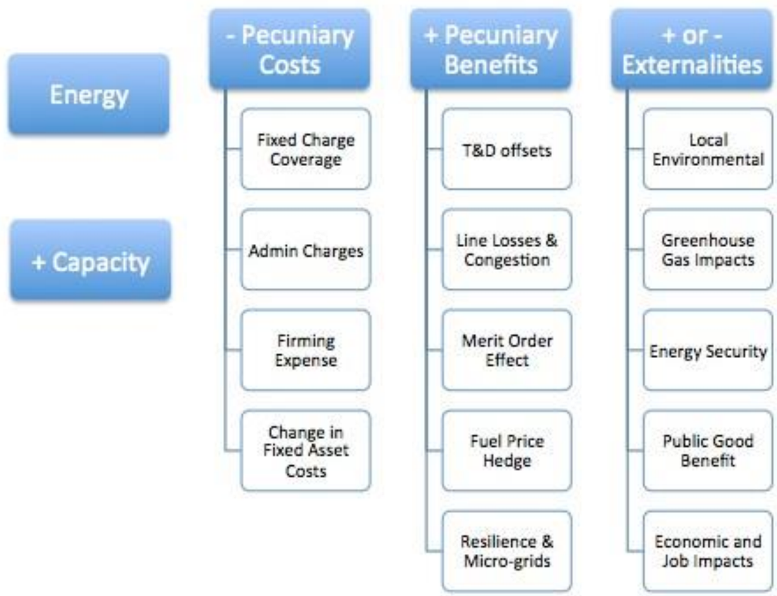
Perhaps the most analogous example to the challenge facing the electricity industry today is the more recent experience of the telecommunications industry. Customers who have not fully transitioned to cellular service bear the costs of the traditional, copper land---line infrastructure, and traditional 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. <u>Proper recovery of these costs is a key concern for utilities and consumer advocates</u>.

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.

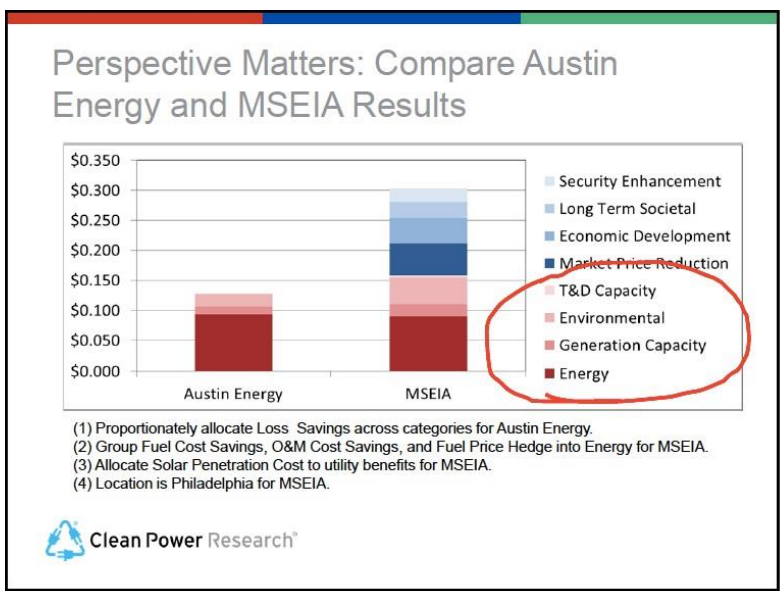


Figure 2. A sample of the Austin Energy Value of Solar Tariff (VOST) (Courtesy: Tom Hoff)

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).