White Paper

The Value in Distributed Energy: It's All About Location, Location, Location

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Shareables

1. A more accurate value of Distributed Energy Resources (DER) means distribution utilities can spend smarter and avoid mistakes on bad capital allocation and inflated tariffs.
2. To turn DER from threat to opportunity, utilities and regulators will need new methods to value not just what is going on the grid, but where it is located.
3. New methodologies under development can rapidly accelerate DER penetration.

Executive Summary

No topic has dominated the power conversation recently as much as the rise of distributed energy resources (DER),[1] and for good reason. As DER assumes a larger role in how energy is generated, consumed, and managed, there are already effects being felt throughout the grid today, and not fully understood implications for distribution, transmission and generation system planning and operations, both now and into the future. The effects—and potential benefits—could be enormous. But such benefits do not accrue equally in all places, across all technologies, or to all users, nor do they always stack up against integration costs as a net positive.

[1] Distributed energy resources include energy efficiency, demand response, distributed renewable and clean generation, energy storage and electric vehicles.

That is why determining the true, locational net value of DER has become so important, both now and as the foundation for managing a transition to a high-DER future. Utilities and regulators can already use (and in states such as CA, HI and NY, are actively working towards developing) an accurate, location-based measure of DER value to make smarter investments, set rates to reflect more equitable value, and optimize programs for energy efficiency, demand response, and renewable and storage deployment.

The approaches used previously in many states for estimating the narrower value of solar (VOS) are now woefully insufficient: inconsistency and skewed assumptions led to wildly divergent estimates. Previous work using prescribed, top-down methods did not account for locational net value—but with DER, location matters—and analyses must now be applied across DER technologies with differing characteristics. Value of DER is now a far more technically-demanding and complex analysis.

In this paper, we describe how ICF has undertaken such an analysis for a California utility and how the findings can provide insights and contribute to improved planning and investment. In the future, we plan to look at how this analysis can be applied across the electric system to integrate other aspects of the grid into a more distributed future.

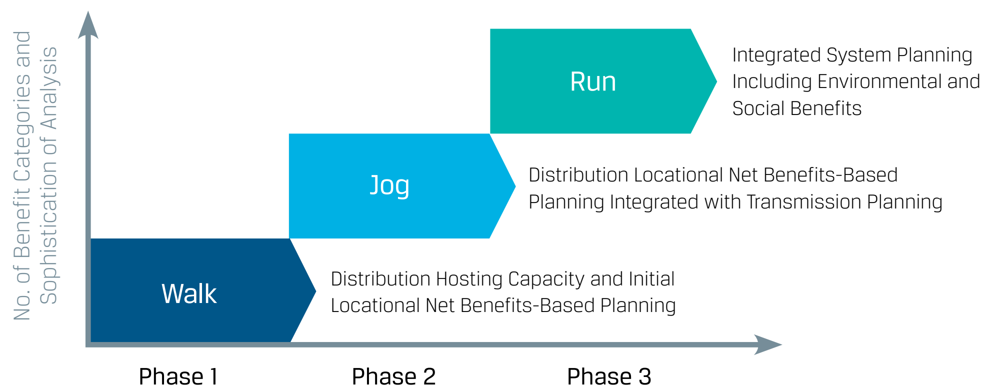
Why Value of DER Matters, Today and in the Future

Utilities and regulators are trying to understand the potential opportunities and systemic implications of increasing customer adoption of Distributed Energy Resources (DER). They are recognizing that as DER assumes a larger role in how energy is generated, consumed, and managed, there are potentially both beneficial and detrimental implications for distribution, transmission, and generation system operations and planning, both now and into the future.

Some of these effects could create real and substantial net benefits for all stakeholders: a potential for lower system costs, better resiliency, savings for customers, and emissions reductions. There are also serious concerns to navigate: operating a system with greater variability in net load, challenges in managing distribution voltage, integration costs, and fair and reasonable cost allocation. The more highly distributed future also will have tremendous potential implication for use of the grid. There are also implications for the utility operational and business model, including the role of the Distribution System Operator (DSO), which we will be exploring further in future papers.

For some states, the future is now, as they are being pushed by (or want to enable) rapid DER adoption and have already launched groundbreaking regulatory initiatives to consider far-reaching changes in tariffs, distribution planning policies, and markets to enable and integrate DER.[2] Other states are not at that point and are focusing on a more traditional suite of policies to accommodate (or incentivize) DER interconnection. An evolutionary progression toward the future has been depicted in California through the "Walk, Jog, Run" framework, shown below.[3] It shows the increasing sophistication of analysis needed over time to progress from understanding and delivering distribution-level DER value to system-wide and societal value.

INCREASING POTENTIAL DER BENEFITS AND SOPHISTICATION OF ANALYSIS NEEDED OVER TIME



However, regardless of the current trajectory of a particular state, this graphic underscores the degree to which determining both the hosting capacity of the distribution system and the true, locational net value of DER are important both now and as the foundation for managing a transition into a high-DER future. A comprehensive, consistent framework that appropriately weighs benefits and costs is the basis for rate design, programs, integrated system planning and platforms, and market mechanisms for sourcing DER services. Getting it wrong could leave a utility or an entire state misaligned, with inefficient capital allocation, misaligned tariffs that benefit some customers over others, and increased costs to maintain reliability. Getting it right—and consistent—unlocks opportunities for customers, market participants, and utilities to optimize products and services, create new markets, and ultimately grow revenue sustainably.

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[2] We examined some of these initiatives in ICF's previous paper in this series, "On the Grid's Bleeding Edge: The California, New York, and Hawaii Power Market Revolution," in which we demonstrated how they are converging toward reconsidering the basic utility model: http://www.icfi.com/insights/white-papers/2015/california-hawaii-new-york-power-market-revolution. Each state fundamentally envisions the future regulated utility as an enabler of customer choice to manage energy costs through advanced distribution planning, modern integrated grids, and opportunities for DER to provide market-based grid services.

[3] Developed by the More Than Smart initiative in support of the CPUC Distribution Resource Plans.

How Utilities and Customers Can Benefit from Accurate Value of DER Analysis Today

- **Smarter Investments:** Utilities can plan and justify better distribution system capital expenditures, achieving required system characteristics at lower cost. Not all savings will match Con Edison's proposed and much-heralded Brooklyn-Queens Demand Management program to save a net $750 million in new substation and transmission line costs through a reduction of 52 megawatts. However, even on a less bold scale, there are meaningful opportunities in every distribution system to optimize investments through a better understanding of hosting capacity and locational DER benefits.
- **Designing Rates:** Determining net locational DER value can help utilities and regulators move beyond net energy metering to intelligent value of solar/DER tariffs that incorporate locational and temporal value—and that deliver fair and reasonable value for all customers.
- **Optimized Programs:** Value of DER analysis can drive assessments of customer programs and incentives to rationalize them and reflect true costs and benefits of energy efficiency, demand response, energy storage, and renewables deployments, both in terms of locational targeting and incentives.
- **Greater Reliability:** DER alternatives to traditional system investments can enhance resiliency and reliability.
- **Anticipating Customer Adoption:** Customer adoption of DER is driven by both policy and technology innovation. This means that forecasting adoption becomes paramount for planning the use of the distribution grid and related investments, including integration costs. Probabilistic scenario-based planning that includes both hosting capacity and net value of DER analyses is critical for meeting customers' needs.

Achieving a "true" net value of DER creates a path for utilities to drive an integrated planning process to realize net positive value for all customers.

Valuing DER Up to Now

The focus in valuing DER until now has been the narrower value of solar (VOS). This has made sense given solar's leading position among deployed DER, with over 9,000 MW installed in the U.S. as of Q1 2015.[4] But, the approaches used previously to determine benefits and costs for distributed solar are woefully insufficient for both the current reality and the future of DER for three reasons.

First, integrating and optimizing other forms of DER requires a benefit-cost analysis (BCA) framework that can be applied across DER technologies. This framework needs to address a range of resource characteristics such as dispatchability, the ability to provide voltage support, and whether they are inverter-based or generate AC directly. Any methodology needs to capture

[4] "U.S. Solar Market Insight Report | Q1 2015." GTM Research.

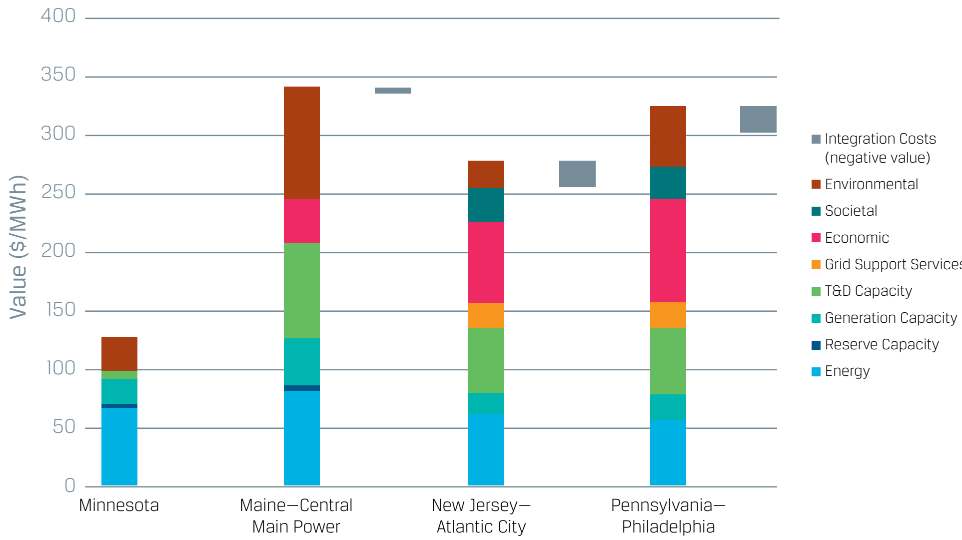
these and other capabilities appropriately, or risk being wildly off the mark. An inaccurate BCA not only fails to optimize investments and programs, it will lead to misallocation of capital and potentially undermine market strategies.

Second, as we highlighted in our previous white paper "The True Value of Solar,"[5] VOS analysis has sorely lacked a consistent and accurate approach. Many previous studies have been skewed by the fact that they either seem to incorporate an implicit assumption—without empirical validation—that distributed solar PV has inherent value, or they explicitly include "social" or other values that are not applied on the same basis to wholesale connected renewables. Predictably, the results have been all over the map, with some studies calculating overall values at many multiples of others, benefit categories variously included or excluded and derived from differing methodologies, and integration costs considered inconsistently or not at all. Such studies, even the most methodologically rigorous, have therefore tended to contribute to confusion and discord rather than promoting progress on aligning DER tariffs and regulations around enabling DER. How are regulators supposed to weigh one study that says the value of solar is $125/MWh against another that claims nearly $350/MWh, and make a fair and rational policy? And how do utilities plan investments, optimize value, and figure out whether added solar is a cost or a benefit to their system?

Third, many existing studies have focused only on system value, not locational net value. They rely on generic, top-down, system-wide values assigned to items such as avoided transmission and distribution (T&D) losses and deferred capacity investments. But location matters. The value of DER within the distribution system is highly dependent not only on its technological capabilities, but also where it is placed and the topology of the system. Therefore, DER benefit-cost analysis must include methods for assessing locational net value. This is important regardless of whether a state is trying to aggressively integrate DER to address environmental policy, reduce system costs, or is simply trying to maintain an appropriate policy for solar PV interconnection. It is also vital for determining fair tariffs that reflect costs of the system and allocates them to users reasonably. Achieving a "true" net value of DER creates a path for utilities to drive an integrated planning process to realize net positive value for all customers.

[5] http://www.icfi.com/insights/white-papers/2014/true-value-of-solar.

ILLUSTRATIVE VALUE OF SOLAR STUDIES: A WIDE RANGE OF METHODS, INCONSISTENT RESULTS



This is why ICF argued in "The True Value of Solar" for a more consistent, rigorous, and empirically based approach that is credible across stakeholders and regulators. The expanding relevance of DER and the future vision enunciated by regulators has only increased the urgency.

Valuing DER Today—Best Practices

To be clear, the process of figuring this out and getting it right is far from easy. There are several steps to establishing the locational benefits and costs of deploying DER on a given distribution system, and they are both more technically demanding and more complex than traditional analysis.[6]

Utilities can assess whether they can avoid or defer other investments through DERs, and thereby or achieve better value at lower cost for their systems and their customers.

- The starting point is a hosting capacity evaluation at the feeder level. Hosting capacity is the maximum DER penetration for which a distribution grid can operate safely and reliably. This analysis establishes a baseline for identifying incremental investments needed to integrate scenario-forecasted DER and net load growth.[7]
- Power flow models coupled with probability-based scenarios can then help quantify the impact that increasing DER adoption with variable characteristics has on specific distribution circuits with regard to thermal overloads, voltage stability, power quality and relay protection limits. Traditional distribution engineering analysis based on deterministic assumptions of DER operation and net load will need to shift to probabilistic methods, to capture the operational impacts of DER variability.

[6] We refer in several places below to examples drawn from California, which has the most developed requirements in its Distribution Resources Plan regulatory proceeding thus far.

[7] Hosting capacity will also change over time as a function of aging infrastructure replacement, grid modernization investments, and net load growth and DER penetration rates. So, this analysis needs to be periodically updated.

- In addition, a scenario-based approach, using at least 10 year forecasts, enables planners to evaluate DER growth across technologies and under varying levels and patterns of adoption as well as the impact on load profiles and variability of net load. California is using Base, High, and Very High DER penetration scenarios to inform this planning analysis.

It is then possible to examine, on a feeder-by-feeder basis, the incremental infrastructure or operational requirements that DER can meet either by providing grid services and/or through better locational adoption. In other words, utilities can assess whether they can avoid or defer other investments through DER, and thereby or achieve better value at lower cost for their systems and their customers.

Case Study: Pioneering New Methods for a California Utility

California investor-owned utilities were required to file Distribution Resource Plans (DRP) on July 1, 2015, providing a framework and methodology for valuing DER. As part of this filing, ICF worked closely with a California investor-owned utility to develop the methods for quantifying locational value in terms of avoided costs that could be realized under various DER adoption and net load scenarios.[8] We focused initially on one value category required by the California Public Utilities Commission (CPUC): Avoided Distribution Utility Capital and Operating Expenses.[9]

Affixing value to deferred distribution investments requires a detailed analysis framework around the DER value components—we used the framework identified by the CPUC and More Than Smart (MTS) working group.[10] The first step in evaluating the ability of DER to defer conventional utility investments under this framework is to identify the values that each DER can provide and then overlay them with the anticipated needs in the system over the relevant planning horizon. To the extent that a given DER's performance characteristics can address an engineering need—and if anticipated adoption levels are sufficient to address the projected deficiency—then that DER would be a potential alternative to enable deferment of utility investment.

For the utility, ICF evaluated the distribution capacity and the projected loading on each feeder in the system. The feeder headroom (i.e. capacity minus loading) was the key metric used to characterize the amount of capacity needed and identify

[8] For this paper, we have not provided specific results or locations and have described methodologies generally for illustrative purposes.

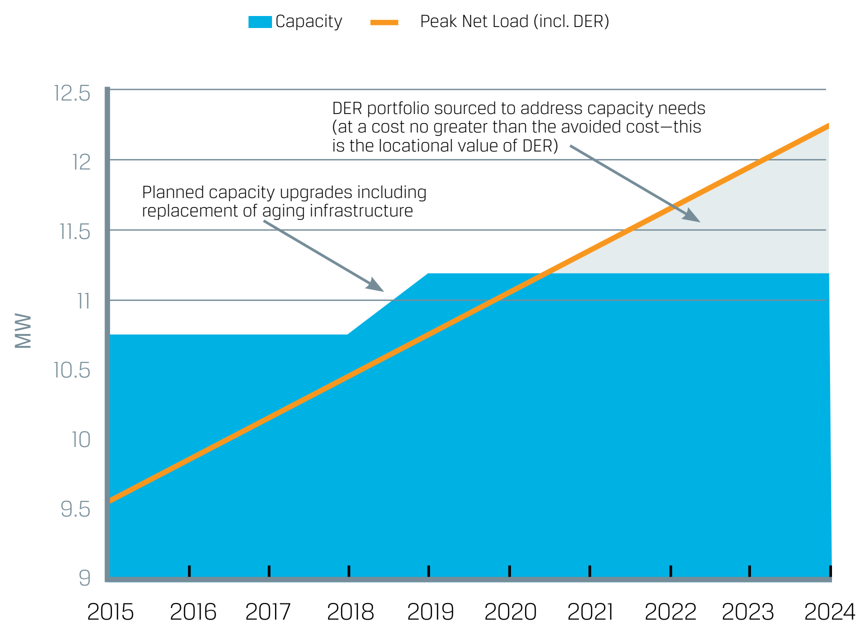
[9] Our analysis focused primarily on distribution capacity, which is only one of the four required DER BCA elements under California's DRP filing. However, the locational value methods developed here provide insights into building the other required elements. In addition, these same techniques, or similar ones, will inform the analysis taking place elsewhere, as New York utilities make their Distributed System Implementation Plan (DSIP) filings in January of 2016, and other states contemplate similar requirements in the years ahead.

[10] ICF is founding member of the California More Than Smart working group as lead facilitator and technical contributor.

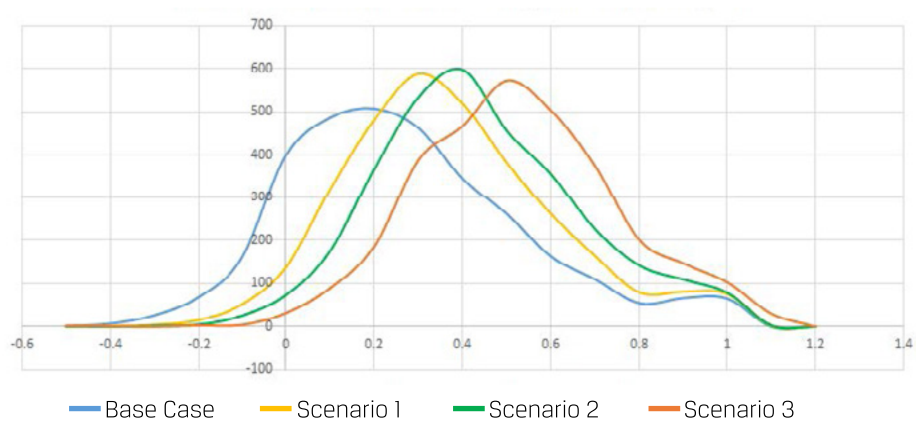
areas where capacity was likely to become deficient. If DER is sourced to occur at the right locations and if the relevant DER can reliably reduce circuit loading when net load is highest, DER could reduce the effective loading on a circuit.

It is important to recognize that the correlation of system output with net load will impact the capacity value of variable resources like distributed solar. The degree to which solar contributes to distribution capacity will vary with location, resource characteristics, and the shape of net load on that part of the system, which will in turn depend on the amount of solar already on the system. The contribution of DERs can be additive, but interaction effects between DER types will influence capacity value. This will become increasingly important as DER adoption increases.

THE IMPACTS OF DER ON DISTRIBUTION CAPACITY BY FEEDER



FEEDER HEADROOM DISTRIBUTION IN 2004, DER COMBINED IMPACTS



ICF's analysis identified the feeders and substations where capacity value from DER could defer the need for incremental capital expenditures on the distribution grid. The top figure above illustrates an example of how a portfolio of DER could reduce effective net loading on a feeder, thereby effectively addressing a projected capacity deficiency and mitigating the need for upgrades. The area in blue shows capacity, while the solid orange line illustrates forecasted net load growth, including organic (i.e., ad hoc and unplanned) adoption of DER. Peak net load begins to exceed the capacity of the feeder between 2020 and 2021, and this deficiency only grows even though capacity is added through replacing aging infrastructure between 2018 and 2019. The gap between load and capacity therefore represents the opportunity for a sourced DER portfolio to address capacity needs, and therefore, the potential locational net value of DER. That value equals the utility avoided costs stemming from the upgrades otherwise needed for incremental distribution to avoid a deficiency, and now provided by DER.

The bottom figure shows the probability distribution for relative headroom on the system under three scenarios of DER adoption aligned to locational value. The shift of the distribution curves to the right (i.e. toward more positive headroom) with increased DER illustrates how adoption, if structured through rate designs and incentives aligned to locational value, could allow for additional DER adoption by maintaining or increasing capacity headroom. This is still only theoretical, of course—today, DER adoption is unstructured as rates and incentives generally do not consider the locational value on a distribution system. As a result, unstructured DER adoption, particularly solar PV, may not actually create any benefit and instead may result in current flowing back into the distribution system during periods of low customer consumption that in turn creates a new net peak loading condition that requires distribution upgrades to address.

Overall, this analysis clearly shows that thoughtful rate design and incentive structures—with active utility participation and input—are essential to realize the net locational benefit of DER for all customers.

Benefits and Next Steps for DER Portfolio Development

Insights into the locational benefits of DER within the distribution system are starting to enable a process in which utilities can specifically evaluate the ability of DER to defer specific projects and upgrades, all within the context of developing a DER portfolio. This sets the stage for being able to value DER differently in different locations, depending on the benefits they might provide and the integration costs they might incur on the system.

The development of a process to enable greater visibility into the value of DER on the system will then enable a distribution planning process framework, through which the full value (and cost) of DER can be accounted for in how they are deployed. That deployment could come through one of three ways—prices, programs, or procurements. These topics will be discussed in future papers.

Conclusion and Key Lessons

Our experience with DER benefit/cost analysis and with clients like our partners in the case study discussed above suggests several takeaways for utilities, regulators, and other stakeholders engaging in the question of determining the "true" value of DER.

1. **Locational net value is key**. Getting the net value of DER right opens up opportunities for delivering greater value, lowering cost, ensuring reliability, and investing wisely. This is important for customers and utilities, and will be increasingly critical in a high DER-adoption future.
2. **Structured DER adoption is essential**. Aligning DER rate designs for Net Energy Metering (NEM) and others as proposed in CA) and incentive mechanisms to hosting capacity and locational value analysis is essential to scale customer adoption of DER. Failure to account for locational value will likely lead to unnecessary capital expenditures to address unstructured (ad hoc) adoption and very challenging operating conditions.
3. **Analysis needs to improve.** Our evaluation of locational value demonstrates that DER value within a system is variable, that methodologies applied until recently and mostly to value of solar are inadequate, and that inaccurate and inconsistent approaches have real consequences.
4. **This is hard, but achievable.** Determining a value of DER—on a locational basis factoring in hosting capacity, scenario-based planning, and probabilistic methods—is hard. However, our experience shows that better approaches are rapidly being developed and can yield smarter results to inform utilities' investments and demand-side resource programs.
5. **Scalable.** The results of our case study, for example, using a consistent and rational true value of DER framework, can be applied across an entire distribution system. Over time, the aggregation of locational value can improve system-wide planning and provide the basis for new market mechanisms and utility business models. We will examine these themes in future papers.

About the Authors

Steve Fine is a Vice President with ICF's Energy Advisory and Solutions practice, and leads the Distributed Energy Resources Team. Steve has particular expertise in evaluating the economics of conventional and renewable energy resources—both central station and distributed generation—within the context of developing market design and environmental regulations. He works with many of the major US power companies and developers in evaluating the impact of environmental and renewable regulatory policies on unit and fleet compliance and dispatch, renewable integration, environmental capex, asset valuation, asset deployment and retirement decisions. He is working with a number of clients to forecast the deployment and the value of DERs on their systems.

About ICF

ICF (NASDAQ:ICFI) is a leading provider of professional services and technology-based solutions to government and commercial clients. ICF is fluent in the language of change, whether driven by markets, technology, or policy. Since 1969, we have combined a passion for our work with deep industry expertise to tackle our clients' most important challenges. We partner with clients around the globe—advising, executing, innovating—to help them define and achieve success. Our more than 5,000 employees serve government and commercial clients from more than 65 offices worldwide. ICF's website is **icf.com**.

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Paul De Martini is a Senior Fellow at ICF and provides advisory services to utilities, cleantech firms and research institutions regarding business, technology and policy development involving the integration of distributed energy resources, market designs and business models. He plays a key role in California's More Than Smart initiative and is an advisor to the New York REV Market Design & Platform Technology working group. He is also a visiting scholar at the California Institute of Technology (Caltech) and has authored and co-authored several DOE sponsored reports and papers on the evolution of the grid and integration of distributed resources.

Dr. Samir Succar is a Manager in ICF's Energy Advisory and Solutions practice and an expert in long-term planning and energy market modeling. He works on a host of issues including distributed energy resource integration, Mexico's wholesale and retail electricity markets, power system modeling, energy storage, gas electric integration and wholesale market design. Dr. Succar analyzes and models power market supply-demand fundamentals, develops forward price curve assessments, and performs generation asset valuations. His transactional experience includes acquisition support for potential bidders, largely private equity and independent power producers (IPPs), and sellers of generation assets and portfolios. His prior research focused on the economics of renewables and energy storage in carbon-constrained systems.

Matt Robison is an Expert Consultant with ICF's Energy Advisory & Solutions team. He has written and developed numerous papers, expert testimonies, and analyses for utility clients on market design, the impact of regulatory programs and incentives, and asset valuation. His particular focus is distributed energy resources grid integration issues and "utility of the future" models, Clean Power Plan implementation, and New England regional issues, especially gas-electric integration.