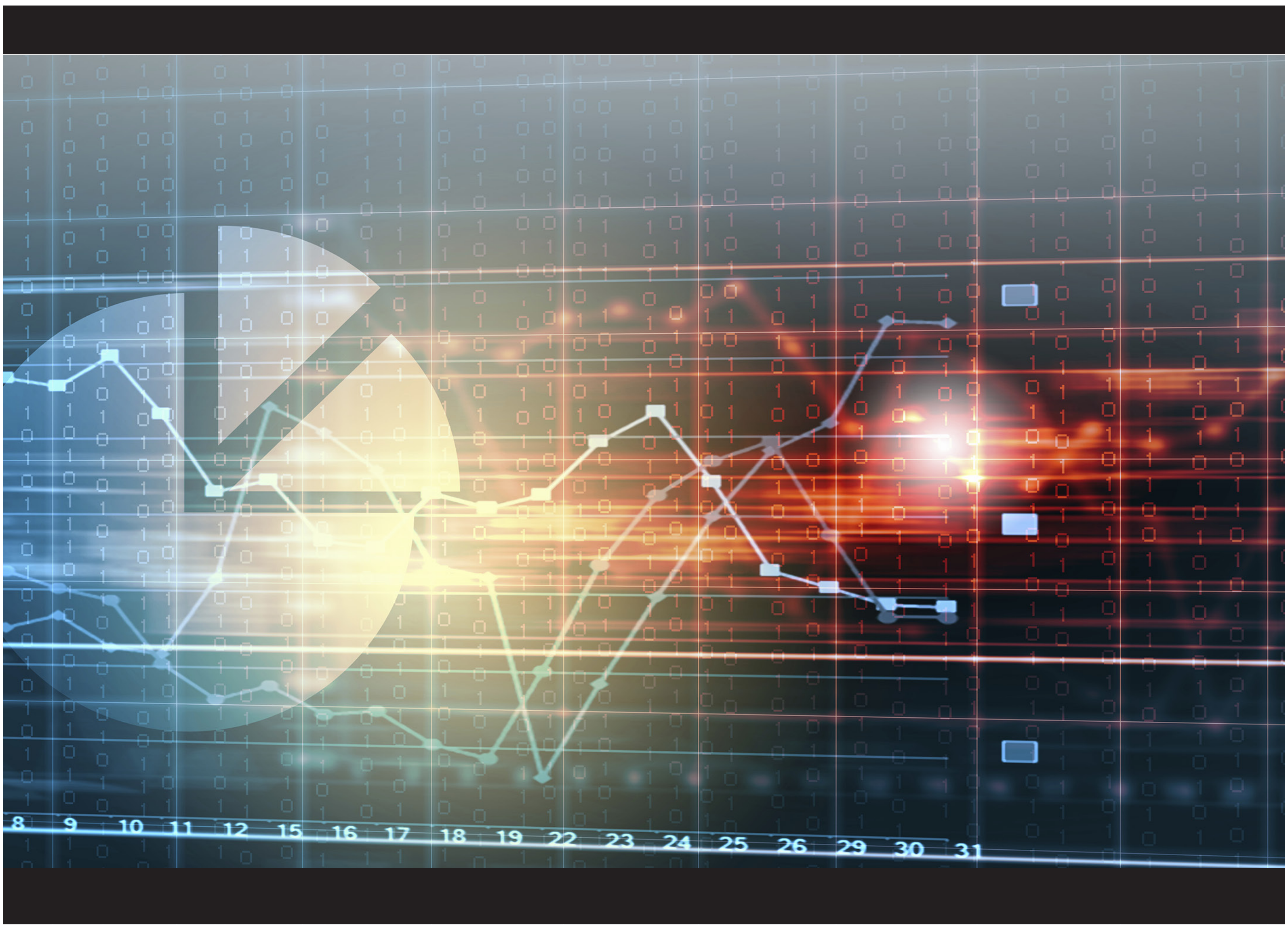
EPRI | ELECTRIC POWER RESEARCH INSTITUTE

CHANGING UTILITY COST PATHWAYS AMID RISING DEPLOYMENT OF DISTRIBUTED ENERGY RESOURCES

Program 174: Integration of Distributed Energy Resources



December 2016

Report Abstract

The greater introduction of distributed energy resources (DER) into the power portfolio is anticipated to alter utility fixed and variable electricity costs. Utilizing publicly available information, predominately derived from FERC Form 1 and EIA 861 data, this white paper illustrates how fixed and variable costs are currently distributed across generation, transmission, and distribution assets for a range of U.S. utilities (i.e., integrated utilities, distribution utilities operating in structured markets, and "hybrid" utilities). It examines how electric utility costs change over time and assesses differences in utility costs according to an array of contextual factors, including utility structural make-up, operating environment, and resource mix.

Recognizing the mechanisms behind the costs of providing electricity service is key to fully understanding how changes in portfolio resources (supply or demand side) can affect total costs, including an appreciation for (when, where, and) why some costs are avoidable while others are not. Ultimately, analysis seeks to objectively inform utilities, regulators, and policy makers about the costs of providing electric power service as they consider cost recovery strategies that can equitably accommodate greater DER usage.

Thinking Holistically about the Value of the Electricity Grid

For many, the electricity system is a complex arrangement of unknowns that collectively enable the generation and delivery of power and energy. Power plants produce electric energy that is delivered to consumers over a network of power lines to meet consumer demand. What is largely unrecognized are the numerous services that are needed to satisfy all aspects of consumer demand with acceptable quality and reliability. This includes services such as capacity,[1] ramping, voltage management, and frequency regulation. The power system is comprised of physical assets that are planned, maintained, and operated as required to provide electric power with acceptable quality and reliability. The costs of these assets and operational activities are the focus of utility cost accounting for ratemaking purposes.

Throughout their history, regulated electric utilities have built and operated their systems with an expectation that they will be able to recover prudently incurred expenses and investments required to provide reliable electric service. However, recent forces—such as increased consumer investment in energy management and renewable technologies, distributed energy resource (DER[2]) cost reductions, advances in communication and interoperability, and policy and regulatory developments—are changing the paradigm of the traditional electric power system. It is being transformed from a one-way central-supply structure to one that must physically accommodate and properly account for bidirectional power flows on the distribution system caused by interconnected DER.

Self-generating consumers, those with storage devices, and those who wish to participate in demand response (collectively known as "prosumers") are altering the design and operational requirements of the grid. Meanwhile, new loads, such as electric vehicles and heat pumps that alter the demand profile, combined with distributed self-supply sources, are anticipated to further affect the system load shape and impact the way electric power is provided, both technically and commercially. Given the changing landscape of the electric power system, examining the physical and economic tradeoffs presented by the projected changes can help inform ongoing and future debate about optimal approaches for the power system's evolution.

Previous EPRI reports have described the cost and value of a variety of grid services, demonstrating that an integrated grid can more fully realize the value of the resources employed to generate and transmit

Table of Contents

This white paper was prepared by Jeff Roark, Steven Coley, and Nadav Enbar of the Electric Power Research Institute.

[1] The word *capacity* has multiple meanings in the electricity industry. Capacity may refer to delivery capacity (i.e., the max power throughput of equipment needed to deliver energy to a specified load—often measured over minutes depending on the amount of time it takes for T&D assets to overheat to failure), or supply capacity (i.e., the max power output of supply based resources to meet peak demand for a specified load—often measured over minutes to hours). It may also refer to startup power (i.e., the large amount of power needed to operate some equipment such as compressors, transformers, and welders—often measured in times scales of less than one second).

[2] For the purposes of this paper, DER refers collectively to all types of distributed energy resources or initiatives at the edges of the distribution grid, including energy efficiency, distributed generation, electrification, demand response, and energy storage.

electricity. The Integrated Grid concept paper[3], developed with input from utilities, regulatory agencies, equipment suppliers, and non-governmental organizations, focuses on the main issues of integrating DER into the power system and stimulates fact-based discussion. A follow-on paper about capacity and energy[4] addresses the roles of not just energy, but also capacity in its various guises. It introduces the cost concepts that have been established to provide capacity, reviews wholesale market and retail rate structures, and outlines existing research gaps that must be addressed to fully leverage DER. Further, EPRI's Integrated Grid Benefit-Cost Framework[5] provides a holistic approach for evaluating the economic tradeoffs of anticipated and prescribed changes to the grid.

The diversity of policies, resource mixes, demand profiles, and regulatory frameworks governing the design and operation of the electric power system across different regions of the country presents an ongoing challenge. The economic impacts of specific power system changes are likely to differ among utilities because of the variety of factors that distinguishes one service territory from another. The reason is, in part, due to the differences in the nature of the fixed and variable costs associated with the design and operation of the power system. A full understanding of the contextual differences in the cost structures of different utilities around the country is therefore needed to properly compare and evaluate techno-economic studies from different service territories and perspectives.

This white paper seeks to inform utilities, regulators, policymakers, and other stakeholders about the range and character of costs required to provide electric power services to society. Differences in utility cost structures are examined by leveraging objective, transparent data from publicly available filings (FERC Form 1 and EIA 861 data). Concluding remarks reflect on how cost structure differences among diverse regulatory settings affect the way that changes to electricity resources, such as the proliferation of distributed energy resources, impact the costs of electric service.

The Utility-Cost Function

The Utility-Cost Function is here defined as the total of all costs within the utility that are assumed to be associated with prudent investments and business activities and passed to customers[6] through rates. It is composed of costs associated with operating expenses like fuel, labor, and taxes, as well as costs associated with capital investments, such as depreciation, property taxes, and interest on long-term debt. Figure 1 (see page 4) illustrates these costs as represented in the income statements, from 1996 to 2015, of an investor-owned utility (IOU) [top] and a distribution utility that was divested of its generation in 2000 [bottom].

The difference between the cost components of these two utilities reflects differences among utilities in the types and relative sizes of cost components. The example IOU shows steady growth in costs over time, and some use of purchased power[7] in addition to fuel cost. The distribution utility, meanwhile, shows a more interesting story. In the first six years it is an integrated utility with generating assets. Its costs change abruptly in 2001, when it divests its power plants. With the exception of purchased power, every cost category is reduced in that year, and the fuel-expense category disappears altogether to be offset by greater purchased power.

General cost-accounting principles classify some of the costs illustrated in Figure 1 as variable and others as fixed. Variable costs are those that change with increases or decreases in throughput or sales. For example, fuel and reagent[8] costs vary with respect to power plant output. Costs that do not vary with respect to sales or output are considered fixed and include everything other than fuel, reagents, and purchased power costs. The cost of purchased power is likely mostly a variable cost, although a long-term power purchase contract could have some fixed components[9].

Note that the terms fixed and variable have no official implications and are purely descriptive. In fact, fixed costs can change, just not directly with product throughput. Of the costs illustrated in Figure 1,

3 *The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources*. EPRI, Palo Alto, CA: 2014. 3002002733.

4 *Capacity and Energy in the Integrated Grid*. EPRI, Palo Alto, CA: 2015. 3002006692.

5 *The Integrated Grid Phase II: Development of a Benefit-Cost Framework*. EPRI, Palo Alto, CA: 2014. 3002004028.

6 Unless otherwise specified, "customers" refers to the entire group or block of customers of the utility, or of an entire customer class if one is identified. The subject of this paper is not cost shifting among individual customers within a class, or between customer classes under the same utility. Rather, the subject is an examination of how DER or any load change at the customer level can affect the utility-cost function that determines the costs to be recovered from all customers of the utility, without regard to how customer rates might affect the distribution of cost responsibility among customers or classes.

7 Purchased power refers to power purchased by the utility for resale to customers.

8 Reagents are chemicals used in power plants to boost efficiency and/or reduce environmental emissions.

9 Some long-term power purchase contracts contain capacity charges that could be considered a fixed cost.

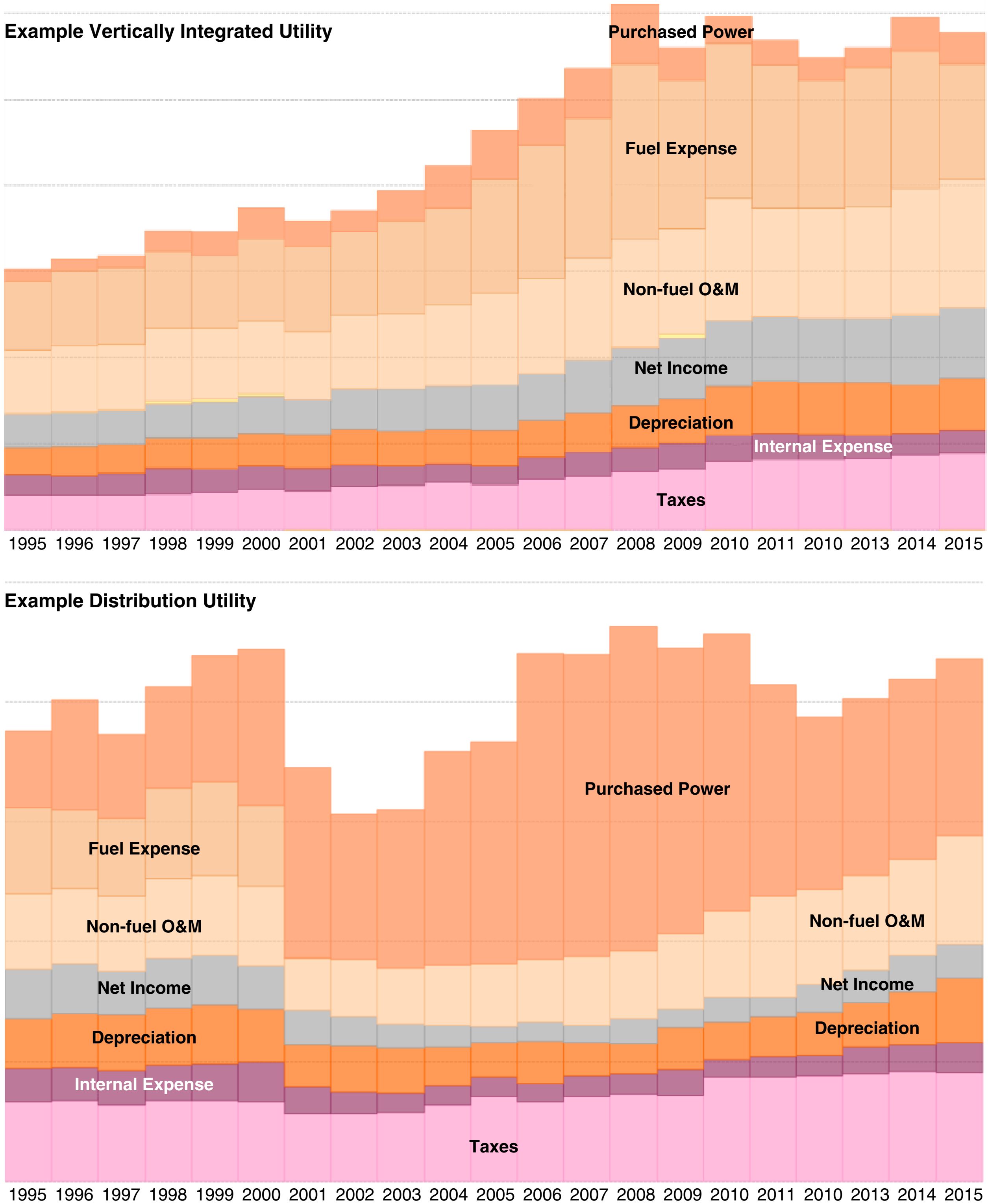


Figure 1. Example components of total cost for a vertically integrated utility [top] and distribution utility [bottom], 1995-2015.
Source: FERC Form 1 Income Statements via Velocity Suite, ABB, Inc.

		Fixed Costs	Variable Costs
Ownership Costs	**Depreciation**	On G, T & D assets	N/A
	Net Income	On G, T & D assets	N/A
	Taxes	On G, T & D assets	N/A
	Interest	On debt for G, T & D assets	N/A
Operating Expenses	**Fuel and Variable O&M**	N/A	Natural Gas, Coal, Diesel, Reagents, etc.
	Purchased Power	Fixed payments on long-term contracts	Variable payments on all contracts
	Non-Fuel O&M	Labor, A&G Expenses, etc.	N/A

Table 1. Fixed and variable cost components of the utility cost function.

Note: Generation, Transmission, and Distribution (G, T, & D) assets include production assets (power plants, transmission lines, transformers, etc., and some non-production assets (buildings, tools) that are clearly part of one function, such as distribution maintenance offices. Non-fuel O&M includes all operating expenses other than fuel, including all types of labor and materials for maintenance.

only fuel and purchased power are variable costs; the others are fixed. Table 1 breaks these costs down even further, distinguishing those that are fixed from those that are variable.

Per Figure 1, each cost component clearly changes year by year. Variable costs tend to change based on annual electricity demand and fuel prices. The variable nature of fuel expense and purchased power is evident in Figure 1 as shown by the increase in fuel expense between 2006 and 2010 for the IOU (top) as well as the rise and fall of purchased power cost for the distribution utility between 2005 and 2012 (bottom).

Fixed costs, however, tend to change in response to investment to support growth, as the utility continues to invest in generation, transmission, and distribution assets. Figure 2 (see page 6) shows how the same assets from the same two example utilities grow over time, as transmission and distribution systems are expanded and enhanced, as generating plants add emissions controls, or as new power plants are built. The IOU shows growth in steam generation investments (top), while the distribution utility shows growth in distribution assets (bottom). The distribution company had fossil steam and combined cycle and combustion turbine (CC/CT) generation prior to its divestiture between 1999 and 2000.

While not explicitly illustrated in Figure 2, the fixed cost associated with a given asset (depreciation, net income[10], taxes and interest) declines constantly as the asset depreciates. So while costs associated with invested assets are technically fixed costs, they change every year. However, the series of declining annual costs associated with an asset (known as revenue requirements) are essentially set when the asset is accepted as prudent and placed into service. Although individual assets' fixed costs decline over time, continued growth and investment in new assets can increase total fixed cost over time.

Cost Differences among Utilities

The fixed- versus variable-cost composition of a utility depends on its type. An integrated utility has variable cost for the energy it sells—usually a combination of fuel, variable O&M, and purchased power. The other extreme is a distribution utility that only *delivers* energy; it never takes ownership of the energy and does not sell to end users. As such, this type of distribution utility, which does not purchase or sell power, has little or no variable cost; its costs are mostly fixed.

Even within the generation function, there are differences among integrated utilities in terms of fixed and variable costs. Today's mix of fixed and variable generation costs is a legacy of prior resource decisions. Utilities in different locations faced different fuel costs, often owing to the distance to fuel resources. As a result, resource decisions reflect economic choices that rely on nearby fuel resources. Historical decisions also depended on forecasted load shapes; some areas have lower load factors than others owing to weather patterns, affecting expected utilization of resources.

That said, in every situation the economic objective of generation planners is the same: to minimize total cost to customers by finding the optimal trade-off between fixed plant costs and variable fuel costs, and weighing decisions relative to the existing generation

[10] Net income is return *on* equity capital while depreciation is return *of* all invested capital. Return on equity capital is part of the investor-owned utility's cost of capital, which is a consideration used by regulators in approving rates. Rates embody an "allowed" rate of return assumed sufficient to attract capital for growth. Net income on a company's financial statements reflects outcomes of rates, sales, and other events during the reporting period, and may be greater or less than the amount implied by the allowed rate. Net income is shown here as a part of the fixed cost of utility service, while acknowledging that net income may include some extraneous influences.

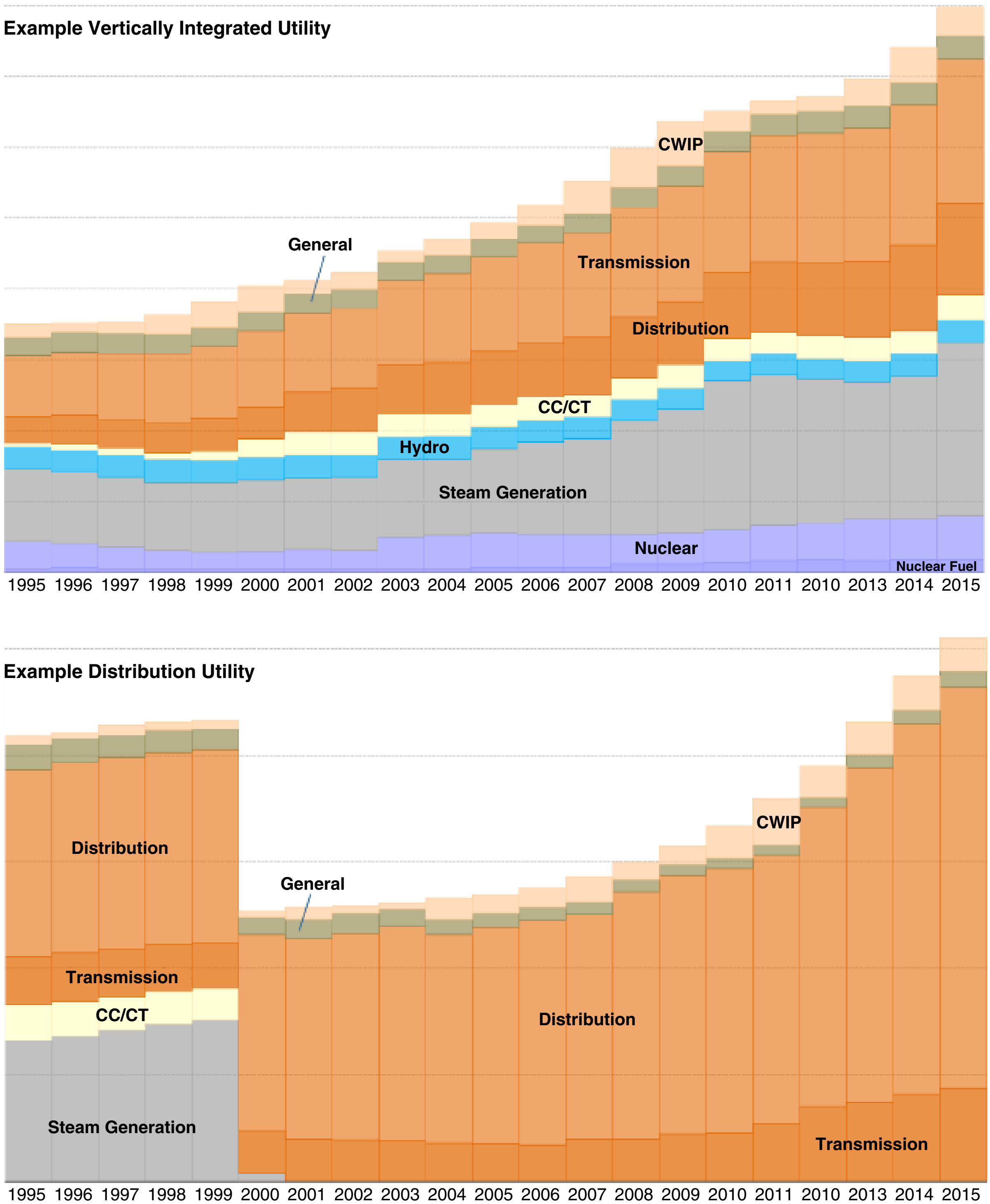


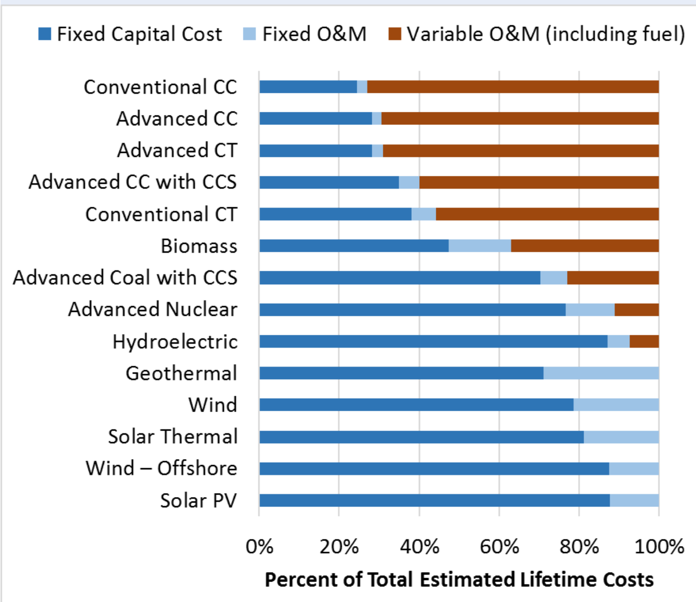
Figure 2. Net utility plant (and CWIP) for an example vertically integrated utility [top] and an example distribution utility [bottom], 1995-2015. Source: FERC Form 1 via Velocity Suite, ABB, Inc.

Notes: CWIP is Construction Work in Progress, and represents the amounts invested in projects not completed by year end, which is technically not part of Net Utility Plant. The General category is investments that can't be classified as G, T, or D, such as general office buildings. Steam Generation is non-nuclear steam. The example distribution utility was vertically integrated until it divested its generation between 1999 and 2000, after which it owns no generation assets.

Fixed and Variable Costs of Generation Options

Traditionally, utility planners have evaluated a variety of generation resources to optimize their resource mix by minimizing the total costs of generation needed to satisfy the full requirements of projected future demand, subject to reliability constraints. As illustrated in Figure 3, this approach requires making tradeoffs between generation options that have different fixed plant costs and variable fuel costs. Typical dispatchable generation options range from high plant costs and low fuel costs to low plant costs and high fuel costs.

Investments made in generation with high capital costs and low variable costs, such as coal and nuclear plants, tend to operate around the clock because they have low variable costs. These investments require a near guaranteed recovery of capital investment due to their high initial cost, but can help keep total costs low because of their low fuel costs. Other investments that have low capital costs but high variable costs may be needed to satisfy only the aggregate peak demand that may occur for only a couple of hours during the year. Many of the renewable technologies have nearly no variable costs, but their fixed costs are substantial while their energy output may be inflexible. Resource plan optimization looks at all combinations of resources that satisfy reliability constraints, and chooses the plan with the lowest total cost, whether fixed or variable.



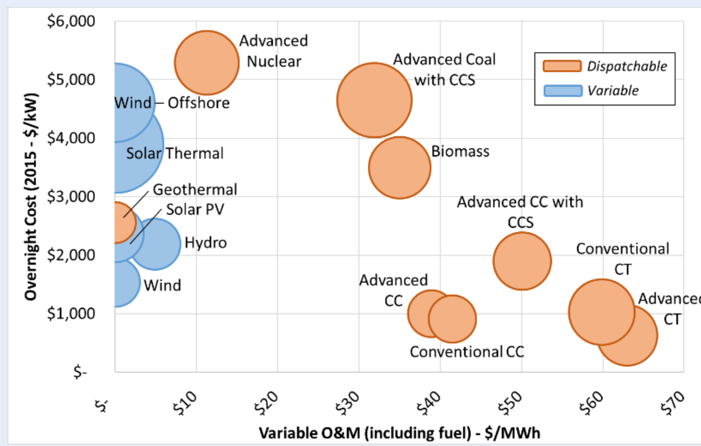


Figure 3. Fixed (top) and variable (bottom) costs of different generation options, as of 2015.
Source: EIA: "Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2016" (Table 8.2) & "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2016" (Table 1.b)

Notes: Size of the circle (right) indicates estimated total levelized costs ($/MWh). Costs represent national averages as reported by EIA. Overnight capital cost represent costs of new projects initiated in 2015 (includes contingency factors – excludes regional multipliers, learning effects, and interest charges).

landscape. The outcomes among utilities have been, and are expected to continue to be, different because of each utility's unique set of circumstances.

Fixed and Variable Cost Differences at the Distribution Level

While instructive to assess total utility costs through public filings of utilities' financial statements, when assessing the impacts of DER, it is perhaps more appropriate to focus on the fixed and variable cost components relevant to customers connected to distribution. To estimate utility costs associated with serving distribution loads, each cost category can be separated into per-unit sales costs and allocated across various customer classes and types based on different retail and wholesale sales categories.[11] This estimated allocation is analogous to the cost allocation process that a utility goes through in ratemaking, but is far less detailed and uses only sales rather than demand by customer-class.

Analysis of publicly available filings from utilities across the U.S. helps illustrate the difference in per-unit cost structure among utili-

[11] This information is available only through the EIA 861 database for revenues, sales, and customer counts.

Estimating Utility Costs Per Unit of Sales for Bundled Distribution Customers

Allocating costs on only energy requires calculating the per-unit costs of each component, recognizing that each component is spread over different types and amounts of sales. This allocation procedure can be accomplished using utility cost data from FERC Form 1 and utility sales data from EIA 861, as illustrated in Figure 4.

For example, fixed generation costs, if any, are spread over bundled retail sales and "requirements" wholesale sales.[12] Generation fixed cost is not allocated over energy delivered for others or non-requirements wholesale sales. Transmission costs are allocated across all delivered load, including delivery energy, bundled sales, and wholesale sales. Because all distribution customers pay for distribution costs, these costs are spread over the total energy delivered on the distribution system. They are assumed to comprise all commercial and residential energy, bundled or delivery-only, but do not include industrial sales, which are mostly connected at transmission. Finally, the total cost allocated to bundled distribution customers is estimated as the sum of these per-unit fixed-cost components and a per-unit fuel and purchased power cost.

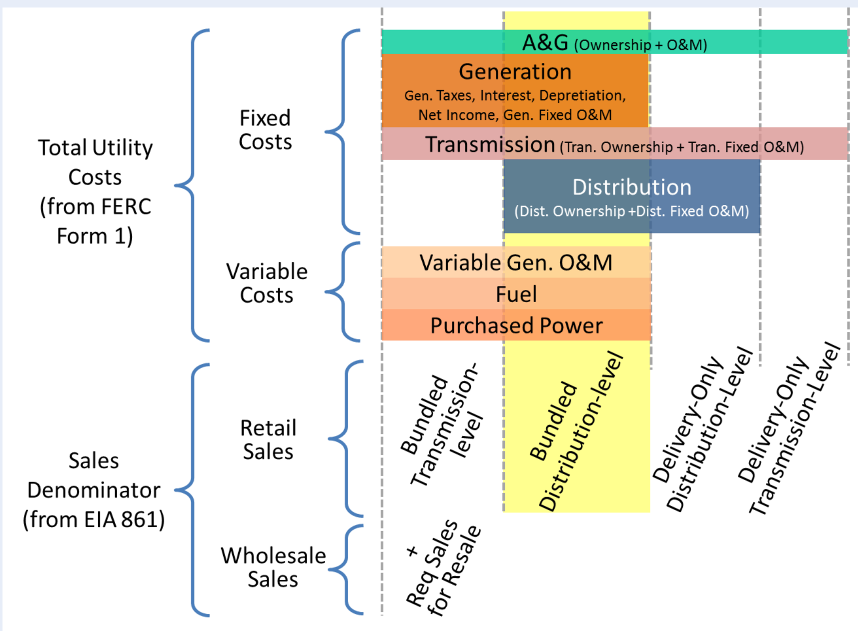


Figure 4. Ownership costs by business function.

Notes: Ownership costs (taxes, interest, return of and on capital) are allocated to G,T,D, A&G by ratio of Net Plant, then spread over different sales amounts as appropriate to the category. Non-requirements sales aren't involved in allocating fixed costs, although it could be argued that they pick up a share of transmission cost. Costs allocated to bundled distribution customers are highlighted in yellow.

ties at the distribution level. Figure 5 (see page 9) shows the per-unit bundled distribution-level fixed and variable cost mix in 2015 for 30 different utilities in six generalized regions[13] and three different utility types (vertically integrated utilities, "hybrid" utilities,[14] and distribution-only utilities). The range of fixed cost as a percentage of total per-unit costs spans from 35% to 85%. Meanwhile, the inte-

[12] Requirements wholesale customers are distribution companies, munis, and co-ops that fully depend on the utility for supply. Requirements customers are included in the load that a utility is obligated to plan for and serve. Non-requirements wholesale sales are to other utilities that have other sources of supply. Non-requirements sales can be under long-term contracts with both fixed and variable price components, but some are simply short-term sales among utilities or spot transactions within a structured market.

[13] Mid-Atlantic [MidAtl], Midwest [MW], Northeast [NE], Northwest [NW], Southeast [SE], and Upper Midwest [UMW].

[14] A "hybrid" utility refers to utilities that are members of structured wholesale markets such as PJM or MISO, but that retain a significant portion of generation within the regulated entity. They may or not be transmission owners, but their transmission systems are under the control of the independent operator. A hybrid utility could also refer to a merchant generation company that sells energy at retail.

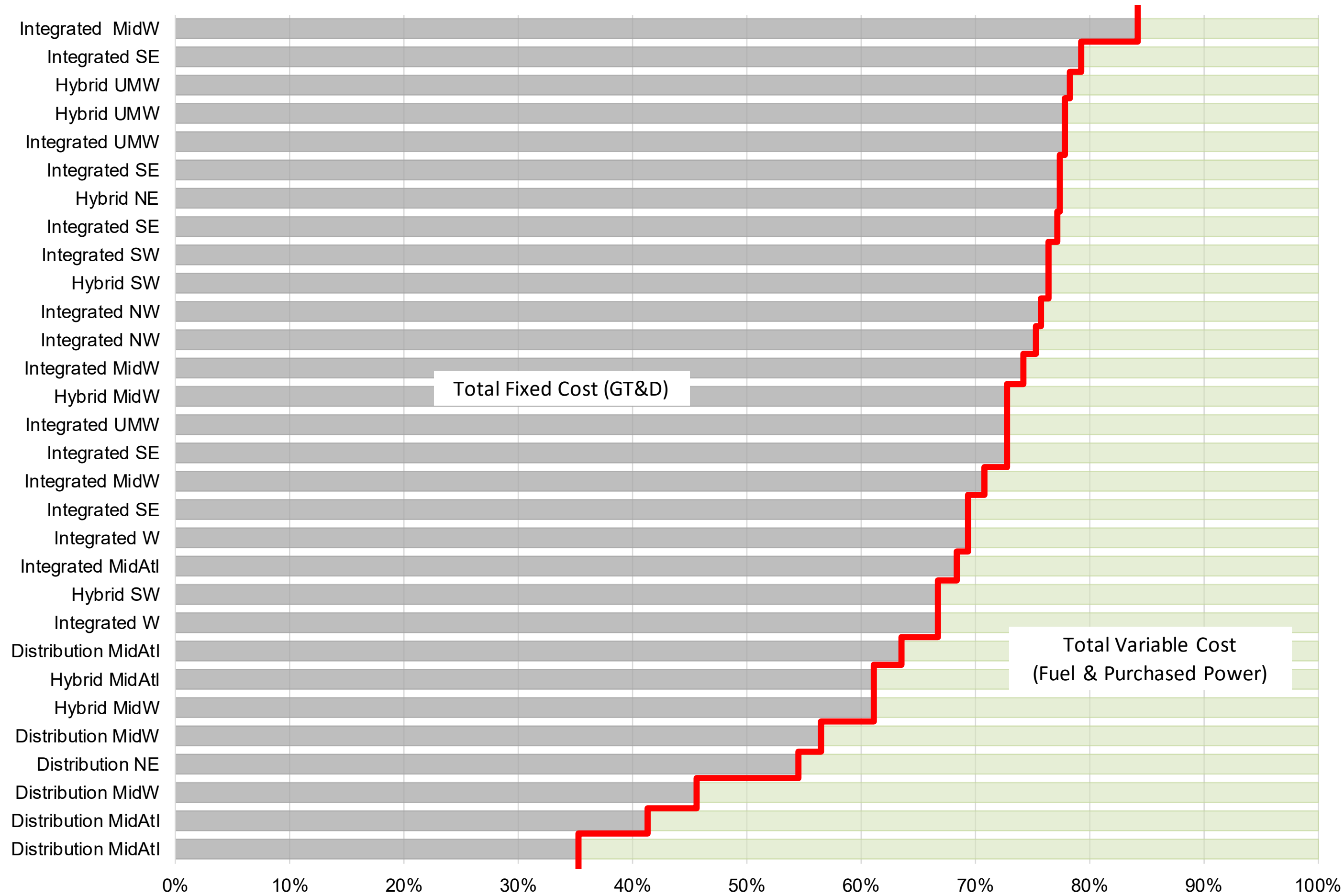


Figure 5. Fixed and variable costs per-unit of sales for bundled distribution customers as a percentage of total, for 30 U.S. utilities in 2015. Source: Based on utility public filings, FERC Form 1 and EIA 861, via Velocity Suite, ABB, Inc.

Notes: Using the estimation process described in the paper, per-unit costs for bundled distribution customers are shown broken into total fixed and total variable. Utilities with generation assets have the highest levels of fixed cost because generation costs are variable for customers of distribution utilities in structured markets.

grated utilities have a higher per-unit fixed cost percentage (ranging from 67% to 85%) compared to distribution utilities (ranging from 35% to 63%).

A closer examination of the type of fixed costs (differentiated between T&D and generation cost) and variable cost (differentiated between fuel cost and purchased power) reveals that there are even more differences in the cost structure of these utilities, as illustrated in Figure 6 (see page 10). Fixed T&D costs range from 29% to 66% of total costs, which is indicative of the differences and unique challenges utilities face when transmitting and distributing power. Utilities with low load density, or perhaps those that have a higher percentage of underground cables, typically have a higher percentage of fixed T&D costs on a per-unit basis. Meanwhile, the percentage of purchase power ranges from 0% (utilities that are self-sufficient) to 75% (utilities that purchase all power delivered to their customers). As previously mentioned (see sidebar, "Fixed and Variable Costs of Generation Options"), the mix of fixed generation cost and fuel cost is dependent upon the generation mix of resources and the fuel costs for those resources.

Economic Pathways for DER: Avoidable and Non-Avoidable Costs

Fixed costs have real meaning for power company accountants. But to what extent is a utility's fixed cost fixed for its customers? This question does not relate to rate structures and the retail electricity bills for individual customers; rather, it corresponds to utility

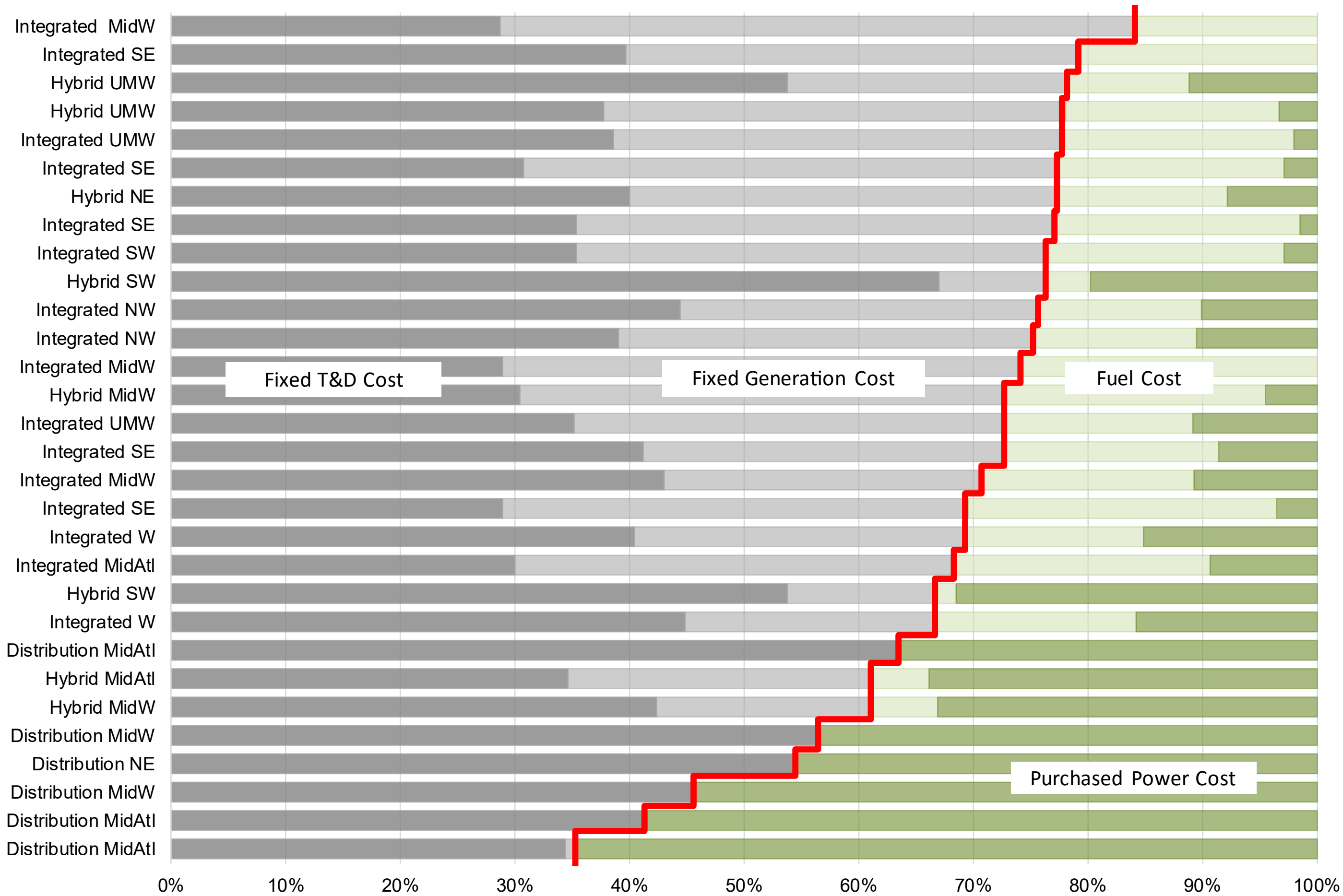


Figure 6. Fixed and variable costs per-unit for bundled distribution customers for 30 U.S. Utilities by Cost Component in 2015.
Source: Based on utility public filings, FERC Form 1 and EIA 861, via Velocity Suite, ABB, Inc.

Notes: This graph is the same as Figure 4 except that additional detail is shown. In particular, fixed generation costs are broken out separately from T&D fixed costs, and Fuel costs are separated from Purchased Power.

economics. What utility costs go away when utility customers buy less power? What utility costs actually increase when customers buy more? It is a central issue that economists and utility planners consider when evaluating investments in DER.

The answers boil down to marginal costs, or the costs added by producing one extra item of a product (i.e., electricity). Marginal costs are distantly related to fixed and variable costs. Some marginal variable costs are immediate and contemporaneous: if a consumer reduces their energy consumption today, an amount of fuel consumption is reduced somewhere on the power system at the same time.

But other cost components are less immediate and "lumpier", such as when changes in load result in changes in unit commitment.[15] Finally, there may be marginal changes in fixed costs, but existing assets are fixed in place for some time and are not easily changed. Changes in fixed costs may not occur until years after their cause. For instance, a utility might be planning to add no capacity for the next five years; reducing load today won't impact the capacity plan for at least that length of time.

Marginal fixed and variable cost components compose "avoided costs" or the change in cost brought by some prospective physical

[15] Unit commitment refers to the process of selecting generating units at power plants to either run or be idle. Starting a unit has a cost, as does running units at their minimum outputs. Unit commitment selects which units are needed to meet economic and physical criteria.

change to the electricity system, such as the installation of customer-owned generation. The concepts played a prominent role in determining compensation for cogeneration units under the Public Utility Regulatory Policy Act (PURPA),[16] enacted in 1978. PURPA recognizes that a cogenerator can allow the utility to avoid some variable cost in the short term, but that fixed capacity costs may not change for quite some time, until the utility's capacity construction plan can adjust to the presence of the cogenerator. In concept, if the utility pays the cogenerator no more than it would have cost the utility to provide the same capacity and energy, then the utility's customers will be indifferent.

PURPA recognizes that certain costs are avoidable by the utility when customers make changes in consumption or add their own generation. While the act's implementation by the states has been uneven, there is common acknowledgement of the difference between the timing of avoidable energy costs and the timing of avoidable capacity costs.

There were, however, no structured spot markets in the U.S. when PURPA was written. Instead, only a patchwork of vertically integrated investor-owned utilities existed alongside publicly and cooperatively owned utilities of various sorts.[17] As a result, any changes in a utility's cost were contained within the vertically integrated structure; investments by those utilities were made to serve the customers within the utility's service territory. Consequently, the fixed costs associated with past investments were not avoidable by the utility's customers, considering all customers as a group. Therefore, any utility-level economic analysis associated with DER on behalf of the utility's entire body of customers, considered the fixed costs of existing investments to be unavoidable by customers. Only costs of future investments could be avoided, changing the fixed-cost path of the utility in the long term. Figure 7 is a stylized hypothetical representation of this concept. A load reduction (from say, an investment in energy efficiency) contemplated in year 3 could avoid variable costs immediately and for the long term. However, that load reduction might have zero impact on fixed costs until year 9 and thereafter. The fixed costs of investments existing as of year 3 are not avoidable by the utility's customers. The fixed costs of some future planned invest-

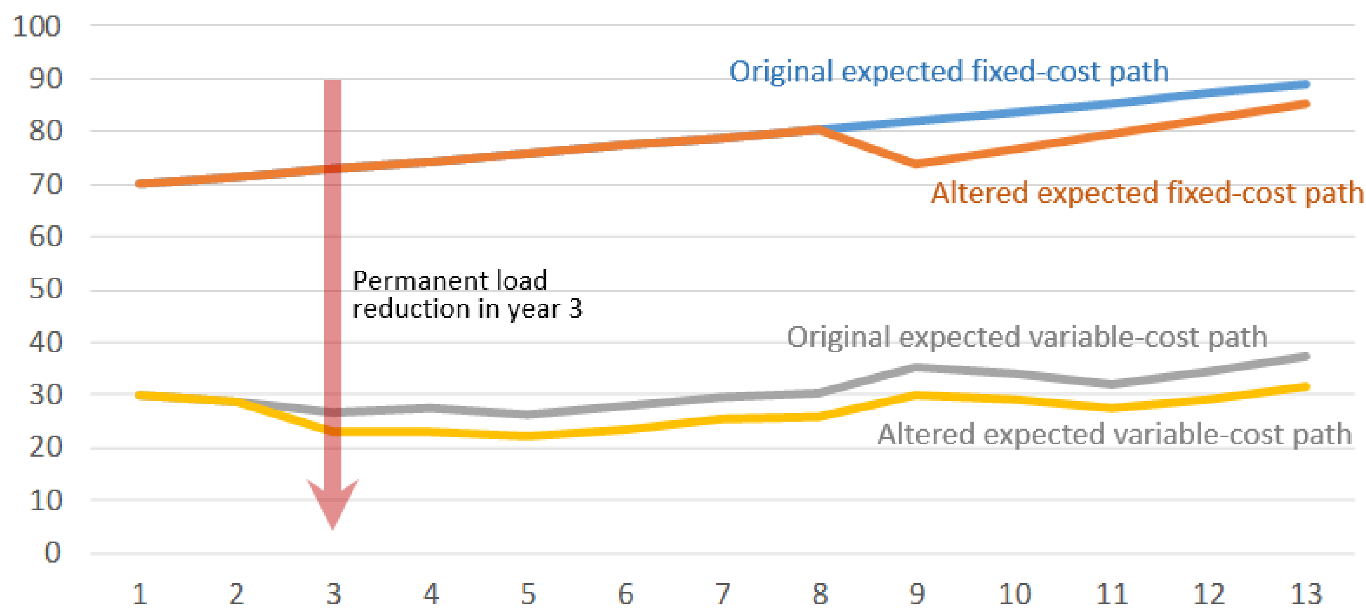


Figure 7. Schematic illustration of a utility's changing fixed costs over the long term.
Source: EPRI

Notes: a load change in the near term may change variable costs immediately, but fixed costs may change years after the fact.

[16] Public Utility Regulatory Policy Act (1978) was intended to promote conservation and domestic sources of energy, including renewables. Among other features, PURPA required utilities to purchase power from qualifying cogenerators installed within their service territories, at rates no greater than avoided cost.

[17] It is common for distribution co-operatives and small municipal distribution systems to buy all their power from cooperative or municipally owned generation and transmission companies. Even in 1978 some cooperative and municipal distribution systems bought power from both integrated utilities and associated generation and transmission companies.

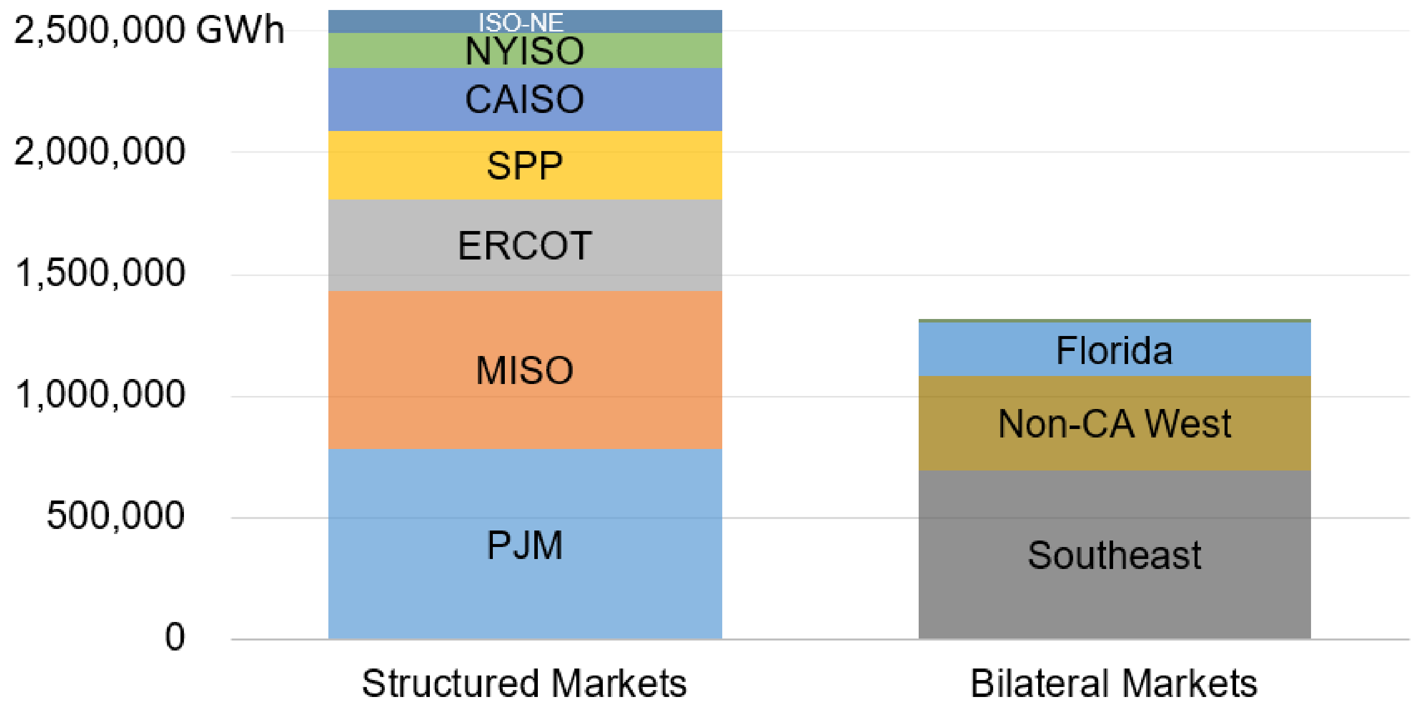


Figure 8. Electricity generated by major plants in the U.S., 2015.
Source: EIA 923 via ABB EV-Power

Note: For descriptions of the various structured markets, see https://www.ferc.gov/market-oversight/mkt-electric/overview.asp

ments might be avoidable by the utility's customers. An economic analysis of this prospective energy efficiency investment would take these timing issues into account.

The Impact of DER on Costs in Structured Markets

While vertically integrated utilities remain in much of the country today, Figure 8 shows that roughly twice as much of the electric energy generated in the United States is in structured markets.[18] These market structures, where much of the energy is generated by independent power producers, change how customer costs are determined. In particular, the economics of DER from the viewpoint of customers in a structured market are affected because of a difference in costs that customers would be able to avoid.

The power bills of customers in a structured market are composed of distribution costs, transmission and operator costs, and energy costs through a retailer or from the market. Customers are physically connected to either a regulated distribution company[19] or a regulated transmission company, and their responsibility for the costs of these systems is the same as when they were fully integrated: the fixed costs of existing assets are not avoidable by the block of customers, but the path of future fixed cost can be altered. However, by market design, energy consumers in the market have only voluntary responsibilities to generators and retailers and can fully avoid some generation costs through investment in DER.

Depending on the market design, a retailer or load-serving entity may pay for capacity in the capacity market, enough to cover its customers' aggregate demand. The retailer can pass these costs to its customers through its rates. The key difference in the economic view for customers in structured markets is that the energy charge and the capacity charge are both avoidable to the retailer in the near term. Naturally, if individual customers in a structured market reduce their energy use today, they may avoid some of the energy portion of their

[18] The term "structured markets," sometimes called "organized markets," refers to spot markets facilitated by an independent system operator such as PJM or NYISO.

[19] A load-serving distribution-only utility in one of these structured markets owns little or no generation, and hence has little or no variable cost of its own. Some distributors simply deliver power and data, and do not sell energy at all; their variable cost is nil. A distribution utility's cost structure is composed of fixed investment costs and labor that are unavoidable by the utility and its customers in the short term. The future path of fixed cost of these utilities, with rising DER on their systems, is unclear.

retail bill. This is significant because the energy portion of the bill in a structured market includes contributions to fixed generation costs that would have been unavoidable in a vertically integrated system. Further, if customers reduce their peak demands, then the capacity charges to the retailer are reduced. It is also an important distinction that these costs aren't shifted to other customers. Rather, market prices are slightly reduced and total generator revenue falls accordingly, an outcome of the competitive market. In fact, when market prices fall, the impacts may be widespread, so that other customers may benefit.

Recovering Fixed Generation Costs from the Perspective of Generation Owners

Unregulated generators and independent power producers in structured markets have fixed and variable costs just like any other company that sells a product. Presumably, a generator recovers its variable cost when it generates in a market, whether it runs a lot or a little.[20] But the fixed costs must be recovered through the sales of all of the products the unit can sell, which includes energy, ancillary services, and capacity if the market supports capacity payments. Generators can and do sell power bilaterally in these markets, and these contracts provide a hedge against movements in spot prices. What the generators expect from a market is even-handed rules that provide a platform for fair competition. However, other than hedges and contracts they may have undertaken, they have no guarantees on fixed-cost recovery.

By market design, investments in generating units connected to a structured market are in competition with all forms of generation on the system, whether it be from other wholesale generators or generation behind the customer meter. This is the nature of the competitive market system. A plant that cannot recover its going-forward cost (the minimum cost to remain in operation) will eventually exit the market. This is not the case for plants owned by regulated integrated utilities which make investments with the obligation to serve its customers. The expectations of cost recovery for the generation investment is markedly different from the perspective of the generation owner depending upon the structure of the operating environment. Table 2 summarizes the comparative differences in the treatment of fixed generation cost for vertically-integrated utilities and independent power producers operating in structured markets.

Avoidable Costs from the Customer Perspective

The types of electric utility costs that are avoidable by customers is different depending upon whether customers are served by vertically integrated utilities or by utilities operating in structured markets. Table 3 (see page 14) summarizes the long- or short-term nature of the kinds of costs which are avoidable by customers of the two different utility types.

Table 2. Comparison of fixed cost treatment for two utility types.

*Note: *Reliability Must-Run (RMR) refers to an asset that is deemed necessary for reliability purposes, and that may be called by the operator to run at cost when market prices would not otherwise cover its costs.*

Definitional Elements	Integrated Utility Generation	Independent Power Producer
Conditions/obligations	Invested for Obligation to Serve	Invested without obligations unless contractual. Obligations may be short term
Capital investment	Investment "affected with the public interest"	Capital risked in hope of investor returns
Recovery of investment	Expected, arguably a right	Expected, but fully at risk
Treatment if stranded (cost not recoverable)	Regulators may allow stranded-cost recovery; often a negotiated result.	Stressed assets are either sold at a loss (and recapitalized) or shuttered. Going-forward cost may be obtained if needed for reliability (RMR*)
Treatment in customer/societal economic analysis	Unavoidable fixed cost, including return at cost of capital	Avoidable to customers, if not contracted; may be included in societal analysis.

[20] For some generators, uplift or make-whole payments are required to cover start-up costs for units required for short periods of time, or dispatched out-of-market for reliability reasons if needed when prices are low.

Table 3. Timeline for avoidable costs by customers of two different utility types.

	T&D Assets + Market Operations		Generation	
	Fixed Costs	Variable Costs	Fixed Costs	Variable Costs
Customers of Vertically Integrated Utilities	Avoidable in the Long Term	Avoidable in the Short Term	Avoidable in the Long Term	Avoidable in the Short Term
Customers of Utilities in Structured Markets	Avoidable in the Long Term	Avoidable in the Short Term	Avoidable in the Short Term	Avoidable in the Short Term

Independent Vertically Integrated Utility

The block of all customers of a self-sufficient integrated utility is charged for the fixed costs of generation, transmission, and distribution, and the variable cost of generation. This customer block can invest in other DER, but the variable cost of generation may be all that is avoidable in the short term. If customer-driven growth in DER changes the needs for future utility investments, then this will alter the future path of fixed costs from what they would have otherwise been. These future fixed cost additions are avoidable, but only when the investment path changes in the future.

Distribution Company in a Structured Market:

The block of all customers connected to a distribution company in a structured market is charged for the fixed costs of the distribution system they are connected to and for a portion of the transmission system and market operation costs. They are also charged for their energy use and, depending on the market, they may be charged for capacity. This customer block can invest in other DER, and by doing so can avoid, beginning in the short-term, a portion of the cost that they would have otherwise paid for generation. Both the variable and fixed costs of generation are avoidable to these customers in the short-term. Future fixed cost additions for T&D assets and market operations are avoidable, but as these assets remain under regulation, they may not be avoided for some time.

A Societal Perspective of Investments in DER

Although customers may be able to avoid fixed generation costs in structured markets through investment in DER, a societal view in structured markets might include lost generator revenue as a cost depending upon what is and is not included within the total societal marketplace in the analysis. For example, within the viewpoint of the electricity market, fuel savings of power plants are often considered to be a net benefit. However, those fuel savings may lead to losses in mining jobs and reductions to returns to investments in mining or drilling. A broader societal perspective that includes the market for the electricity industry and the mining industry considers both the economic gain of savings to electricity customers as well as the economic loss to the mining industry.

The perspective of the economic analysis defines which entities are within the "circle of analysis" and which are external to it, as depicted in Figure 9. In electric utility planning analysis, fuel suppliers are generally considered to be external entities; treating reduced generation costs as an economic benefit in a structured market is analogous.

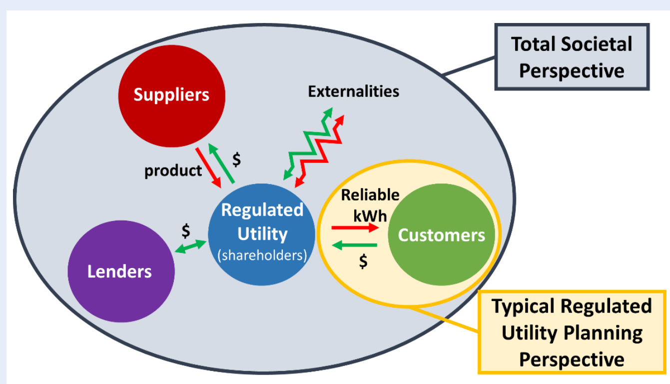


Figure 9. Illustration of the difference in which entities are included in cost benefit analysis from different perspectives.

Note: The "circle of analysis" determines which flows of currency and product are the subject of an economic analysis. The typical regulated utility planning analysis takes the perspective of the customers it serves (yellow circle); it minimizes the cost to customers. This type of analysis includes all costs the regulated utility incurs in pursuit of its obligation to serve, including adherence to reliability, environmental, and other regulatory constraints. For an integrated utility, suppliers of fuel such as natural gas, diesel, or coal are typically considered "outside" the circle of analysis while utility-owned generators are considered within it. In a structured market, power plants may be considered suppliers to customers and may be considered outside the circle of economic analysis. A total societal perspective might include all economic activities of suppliers, lenders, customers, and externalities.

Conclusions and Next Steps

Today's electric utility customers are increasingly diverging from those of the past. Cost reductions in DER, policy and regulatory developments, and rising customer interest in energy management and environmental consciousness is helping to drive DER deployment across the U.S. Greater efficiencies among common load devices such as lighting, computers, screens, and heating and air conditioning systems, are further altering load curves.

Amid today's evolving electricity landscape, utilities, regulators, and other industry stakeholders can benefit from objective and transparent analyses that appropriately evaluate the tradeoffs of both the technical and economic impacts of anticipated changes. In turn, optimal approaches for financially supporting the evolving power system can more adequately be determined. DER additions and changes in consumption patterns alter the dispatch of power plants and the future design and operational requirements of the power system. As a result, the costs required to balance supply and demand must be fully understood by all stakeholders such that regulatory, policy, investment, and cost recovery decisions can collectively enable the development of a more integrated grid.

Although the physics governing the design and operation of the power system are consistent across geographic regions, the regulatory frameworks, policies, and resource economics are not. Accordingly, the fixed and variable costs associated with meeting customer demand vary dramatically given electric utility type, size, and operating environment considerations. The percentage of utility costs that are fixed in the U.S. has, for example been observed to range between 35% and 85%. Consequently, the differences in cost structure affect the economics of incorporating DER into the utility power system.

In particular, the type of market structure and utility serving a market, affects the economic evaluation of DER when viewed from the perspective of a utility's total block of customers because of differences in avoidable costs. Within the construct of a vertically-integrated electric utility, customer adoption of DER avoids the utility's variable cost in the short run and potentially adjusts future utility investment needs in the long run, altering the future path of fixed costs. Alternatively, with the adoption of DER in structured energy markets, a utility's block of customers can avoid the utility's variable costs, which include a share of generators' fixed costs.

Through an assessment of 30 U.S. utilities, EPRI has found that the short term avoidable costs for distribution customers served by integrated utilities averages ~30% of total utility costs. For distribution customers within structured markets, the short term avoidable cost increases, averaging ~50% of total utility costs. This does not mean that DER is more economic in areas served by structured markets, at least from a societal view. The economic competitiveness of any technology is governed by the techno-economic supply and demand characteristics of all resources in the local territory. However, from the viewpoint of electric utility customers, all else being equal, DER could be more advantageous in the short run in structured markets. By letting DER substitute for customer power purchases, the costs of DER can be directly compared to the fixed and variable costs of wholesale generators, rather than to only the variable costs of generation (as would be the case in an integrated utility environment).

Returning to the Integrated Grid Framework

EPRI's Integrated Grid Framework outlines a holistic and transparent methodology for comparing the costs and benefits of anticipated changes to the power system. Subsequent pilot projects are applying the framework, shown in Figure 10 (see page 16), to evaluate the technical and economic impacts of a variety of DER throughout the electric utility industry. The framework diagram in the figure is most suggestive of situations where the impacts on the bulk system are within the analytical circle and their effects on costs are known. While fixed and variable generation costs can be calculated for integrated utilities, in a structured market context, these bulk-system impacts may be embodied within the market energy costs, where the actual fixed and variable components of all the various entities are not known.

Market context has implications for how physical impacts translate to changes in the utility-cost function. As results from Integrated Grid pilot projects and others studies continue to inform the industry, stakeholders will become better positioned to recognize that the fixed and variable costs of providing electric service can differ among service territories. Further, they will gain a firmer understanding of how regulatory contexts can affect which utility costs are avoidable by customers through investment in DER.

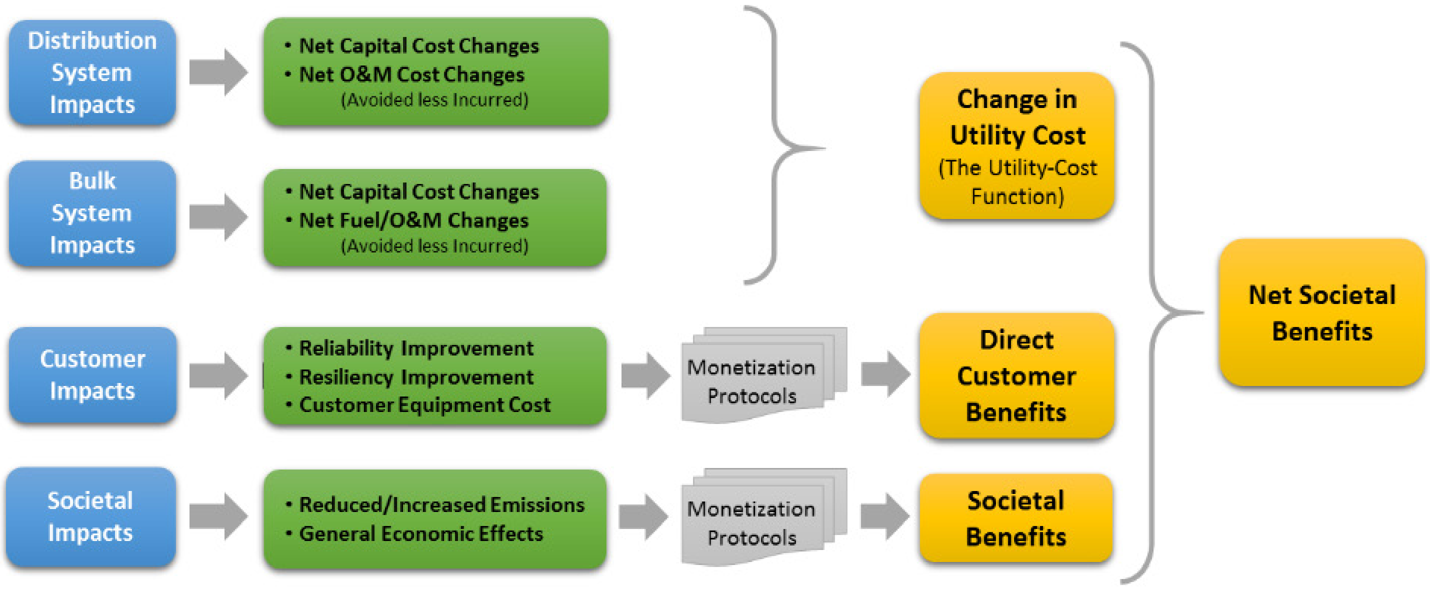


Figure 10. Integrated Grid cost benefit framework.
Source: The Integrated Grid: A Benefit-Cost Framework. EPRI, Palo Alto, CA: 2015: 3002004878

Recommended Reading

Recovery of Utility Fixed Costs: Utility, Consumer, Environmental, and Economist Perspectives. Lawrence Berkeley National Laboratory, LBNL-1005742, Report No. 5, Berkeley, CA: June 2016.

Capacity and Energy in the Integrated Grid. EPRI, Palo Alto, CA: 2015. 3002006692.

Electric Industry Structure and Regulatory Responses in a High Distributed Energy Resources Future. Lawrence Berkeley National Laboratory, LBNL-1003823, Report No. 1, Berkeley, CA: November 2015.

The Economics of Load Defection. Rocky Mountain Institute, Snowmass, CO: 2015.

The Integrated Grid: A Benefit-Cost Framework. EPRI, Palo Alto, CA: 2015. 3002004878.

The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources. EPRI, Palo Alto, CA: 2014. 3002002733.

EPRI RESOURCES

Nadav Enbar, *Principal Project Manager, Distributed Renewables*
303.551.5208, nenbar@epri.com

Tom Key, *Senior Technical Executive, Distributed Renewables*
865.218.8082, tkey@epri.com

Integration of Distributed Energy Resources

The Electric Power Research Institute, Inc. (EPRI, www.epri.com) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, affordability, health, safety and the environment. EPRI also provides technology, policy and economic analyses to drive long-range research and development planning, and supports research in emerging technologies. EPRI's members represent approximately 90 percent of the electricity generated and delivered in the United States, and international participation extends to more than 30 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass.

Together . . . Shaping the Future of Electricity

3002008211 December 2016

Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com