Cost/Benefit Analysis and Challenges for Investing in the Grid

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Abstract

Economic cost/benefit analysis is useful for evaluating prospective investments in terms of their net societal value, but its conclusions may differ from those of a financial analysis taking the point of view of the prospective investor. The investor may be faced with investments of a non-discretionary nature, required by a traditional regulatory obligation to serve, and conventional cost-minimization logic properly guides such projects. But there are instances of discretionary investments that may have positive net societal value where the investor may not find sufficient returns under existing industry structure and regulatory rules.

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What is the role of conventional cost/benefit analysis (CBA) in today's dynamic industry environment? CBA is the traditional planning mechanism of integrated utilities, although in its most basic form the benefit side of the ledger is a given, and the methodology devolves to cost minimization. That is, when a utility is charged with the obligation to serve in an exclusive territory, it need not estimate the value of fulfilling its obligation. Rather, its task is to fulfill its obligations at the lowest possible cost, i.e., planning and operating in a least-cost manner. Obligation service can usually be approached in the traditional cost-minimization framework if the regulatory bargain is intact, even if the traditional utilities are separated along functional lines of transmission, distribution, and/or generation. However, as industry structures have grown more complex, obligations have become divided by corporate boundaries, while some former obligations have been relegated to market forces.

It is the discretionary investment—one that no entity has a clear obligation or responsibility to carry out– that presents interesting challenges. Discretionary projects can provide many benefits to customers: improved electric service over historical standards, reduced cost, value-added services or supply of energy to the power system. Investments expected to be provided through market forces are discretionary by definition, but discretionary investments are also encountered by regulated entities that retain the obligation to serve. In fact, some discretionary investments are the exclusive province of regulated entities—a distribution company does not have competitors, for example, vying to place advanced sensors and reclosers on its lines. But such investments, even if they have net societal benefits, may or may not occur spontaneously among either regulated or unregulated companies. The hurdle for such projects is not the economic question of whether societal benefits outweigh the costs, but the financial question of whether expected returns to investors are sufficient.

As the term is used here, *economic* cost/benefit analysis[1] is concerned with whether a project's total societal benefits outweigh its total costs. Economic analysis requires understanding and forecasting the physical impacts of a project and tracing them to their monetary costs and benefits. While it may look at distributional aspects of costs or benefits among the members of society, economic analysis makes no judgment about them. In general, society should favor projects shown to have positive net benefits by economic analysis, but the analysis may not provide sufficient information for any entity to judge its financial interests in a project. As a logical next step, it is important to analyze who pays the costs and who receives the benefits.

The financial returns to any project depend on the market structure, the earnings mechanism, the form of applicable regulation, and a host of other factors that determine the flows of costs and benefits within the

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[1] The distinction between "economic" and "financial" analysis made here refers to the point of view of the analysis. We use the term "economic" to denote a broad societal point of view. We use the term "financial" to indicate analysis with a specific investor point of view. Economic analysis determines whether the benefits from an investment outweigh its costs, providing sufficient returns to society. Financial analysis is concerned with whether the revenues resulting from an investment provide sufficient returns to the investor, compared with other investments of similar risk.

societal bubble. Such questions are addressed in financial *decision* analysis performed from the perspective of prospective investors and/or other stakeholders, and may reach different conclusions for different stakeholders. Thus for a particular discretionary project with net societal benefits, the distribution of costs and benefits in a particular regulatory/market structure may not favor any financial entity taking it on.

Though economic CBA may identify projects that regulators, policy makers or the public would like to see, it is not intended to identify which investments will take place in a diverse power system growing organically from the bottom up.[2] Conventional CBA is top-down, economic and all-encompassing in nature, whereas bottom-up analysis tends to be financial and parochial in nature, occurring independently in many locations based on local information. Top-down planners cannot be privy to all distributed local information, and while independent bottom-up investors may act on rich local information, their information at the system level may be incomplete. And there is an imbalance between these two types of activities: In most systems, transmission projects are the province of top-down planners using CBA, while generation resources are brought about by independent investors acting in financial interest. Nevertheless, the need for transmission investments is affected by the bottom-up distributed-resource decisions, which may take place on a much shorter timeframe than large transmission projects: grid investments in this environment are challenging because of the variety of risks.

Finally, given that societal/economic CBA is all-encompassing, its scope should contain the economics of societal energy delivery and consumption, not just the electricity sector in isolation. For example, conservation of electric energy is not an end in itself because electric energy has ready substitutes, mostly involving use of combustibles at the point of use. Considering energy use broadly, we might consider whether electric energy delivery is preferable to on-site fuel combustion from both emissions and energy-efficiency perspectives. Concentrating combustion in central power plants offers efficiencies in controlling emissions, but electric energy can also be provided in part by non-emitting renewable resources.

Developing a Cost/Benefit Analysis Methodology

In 2010, the U.S. Department of Energy (DOE) and the Electric Power Research Institute (EPRI) collaborated to establish a methodological approach for evaluating “smart-grid” investments through cost/benefit analysis. The approach was described in a publicly available report[3] that was followed by a guidebook[4] for implementing the method for demonstration projects. The methodology is concerned partly with scientifically measuring the physical impacts of smart-grid devices and systems in specific demonstration applications, while the remainder of the methodology is conventional cost/benefit analysis

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[2] Organic, bottom-up growth in the system is growth through resource additions made by independent investors acting at the wholesale transmission level or at the distribution edge of the grid. Load growth has always been organic, in that consumers decide where and when to consume energy. But bottom-up growth is now more complex because even distribution customers add generating resources. Top-down growth refers to plant and transmission investments made through utility central planning.

[3] Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects. EPRI, Palo Alto, CA: 2010. 1020342.

[4] Guidebook for Cost/Benefit Analysis of Smart Grid Demonstration Projects: Revision 2. EPRI, Palo Alto, CA: 2013. 3002002266.

with the point of view of society or utility customers. Although the methodology is promoted for use in the smart-grid arena, its general economic concepts are useful for analysis of any utility grid project.

In 2012, the European Commission Joint Research Center added to the EPRI/DOE methodology, issuing a set of guidelines for conducting cost/benefit analysis of smart grid projects for the EU,[5] followed by a similar report targeted toward cost/benefit analysis of smart meter deployments. The EU methodology adds consideration of additional functionalities of smart grid devices and systems and describes a multi-faceted scoring mechanism for evaluations.[6]

Application of this CBA methodology to smart-grid technologies has raised these interesting distinctions between discretionary and non-discretionary investments. Smart-grid applications, for example the innovative use of information and communications technology to enhance electric service, are generally discretionary investments and are generally the exclusive province of regulated entities. Some actually reduce the cost of providing the same service, and utilities will likely invest as long as the savings are hard-currency reductions, i.e., cost reductions within the regulated entity itself. However, some smart-grid investments in some regulatory/structural situations can increase the hard-currency cost of the regulated entity while causing savings elsewhere. Economic analysis includes these benefits, but a financial analysis by the regulated entity may not, so incentives or cost-recovery agreements may be needed to encourage such investments.

Examples of Discretionary Projects for Cost/Benefit Analysis

Distribution Automation

A distribution utility can install automation that can improve feeder reliability performance by isolating the faulted segment within minutes, while unfaulted segments can be returned to service through alternative connections.[7] Fault repair crews have good estimates of where the fault is, requiring less search time and perhaps fewer crews to travel to the site. Additionally, remote visibility of circuit conditions along with remote-control capabilities on automated switches can also reduce crew time that would otherwise be required for coordinating manual switching, especially valuable in storm conditions. But while a utility may save money on repair crews and trucks, it may or may not save enough hard-currency cost to be able to recover the cost under its existing regulated rates. Expense reduction is not the only source of value, however. Customers enjoy reduced duration of service interruptions, and such

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[5] "Guidelines for conducting a cost-benefit analysis of Smart Grid projects," European Commission Joint Research Center, April, 2012.
http://ses.jrc.ec.europa.eu/sites/ses/files/documents/guidelines_for_conducting_a_cost-benefit_analysis_of_smart_grid_projects.pdf

[6] "Guidelines for Cost Benefit Analysis of Smart Metering Deployment," European Commission Joint Research Center, March 2012.

http://ses.jrc.ec.europa.eu/sites/ses/files/documents/guidelines_for_cost_benefit_analysis_of_smart_metering_deployment.pdf

[7] Each distribution area is unique, and not all feeders have alternative sources available to them at a reasonable cost. The availability of an alternative source provides the best availability improvement from distribution automation, but even without this reconfiguration capability, distribution automation can reduce interruption durations for some customers.

reductions have clear economic value for customers. These “soft” savings do not accrue within the utility, but this is not an important distinction in an *economic* CBA.

Changes in simple regulatory metrics for reliability such as SAIDI (CML) or SAIFI (CI) [8] can show the physical impacts of distribution automation, but do not capture the economic cost associated with interruptions. The U.S. Department of Energy and Lawrence Berkeley National Laboratory funded development of a tool for estimating the costs of service interruptions based on a meta-study of 28 surveys of utility customers in the U.S.[9] The surveys were taken by the utilities to use as the basis for the Value of Lost Load (VOLL) estimations, which were used primarily for over/under studies of generation reserves. The DOE adaptation of the surveys is more applicable to distribution-level reliability improvement, evaluating the value of service reliability not just on the peak day, but for different durations at different times of day and year. From this work, a publicly available tool (Interruption Cost Estimate Calculator[10]) was developed for estimating interruption costs from standard reliability indices (SAIFI and SAIDI or CAIDI) and the customer mix in an area; it can be applied to entire systems or to individual feeders.

Using such a tool, a complete CBA for distribution automation can evaluate the costs and savings for both the utility and for customers. Customers may have a preference for paying slightly more to achieve higher reliability, especially in locations accustomed to modern high reliability levels. But while the project may show net economic benefits in terms of avoided interruption cost, it may not be financially beneficial for the utility. In some jurisdictions such projects may require presentation of both costs and benefits for regulatory approval for cost recovery through rate base. Where incentives based on reliability indices are employed in lieu of explicit cost recovery, consideration of the economic value and the cost of reliability improvement systems can provide guidance as to the mechanism and magnitude of the incentives offered.

Improving End-Use Efficiency Through Volt/Var Optimization (VVO)

Volt/Var Optimization is a distribution technology incorporating controllable capacitors, load-tap-changing transformers, and/or voltage regulators in various combinations to optimize voltage profiles on distribution feeders. Through enhanced ability to manage and monitor voltage profiles, utilities are able to slightly reduce average delivery voltage levels, which in turn allows some end-use devices to operate more efficiently. (This is often referred to as Conservation Voltage Reduction, or CVR.) Although the utility can reduce technical energy losses in lines and transformers through VVO, the reduction in energy consumption on the customer side of the meter is generally much greater.

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[8] Reliability indices specified in IEEE Standard 1366-2003
SAIDI = System Average Interruption Duration Index, equivalent to Customer Minutes Lost (CML)
SAIFI = System Average Interruption Frequency Index, equivalent to Customer Interruptions(CI)
CAIDI = Customer Average Interruption Frequency Index

[9] Michael Sullivan, Matthew Mercurio, Josh Schellenberg, Estimated Value of Service Reliability for Electric Utility Customers in the United States, prepared for the U.S. Department of Energy, Washington, DC, Contract No. DE-AC02-05CH11231 (2009).

[10] The Interruption Cost Estimate Calculator (ICE Calculator) is available to run online at icecalculator.com. Detailed documentation is also available on the site.

Economically, VVO/CVR is often favorable on distribution feeders on the basis of total cost reduction. That is, the savings in fuel costs are often sufficient to overcome the cost of the added equipment.[11] However, the savings and costs may be distributed among several market participants, depending on the local industry structure. In addition, many customers' marginal retail rates are greater than avoided cost of the marginal generator, who may or may not be associated with the distributor. Without adjustment of the retail rate, customers can save more than the actual cost reduction on the utility side of the meter, leading to a loss of margin by one or more market participants.[12]

Transmission Investments to Relieve Congestion

Not all discretionary investments are smart-grid investments. Transmission investments to relieve congestion fall into the discretionary category unless otherwise required by regulators. Impacts and benefits of discretionary distribution investments are largely local to the customers on the specific distribution circuit where they reside. In contrast, investments in the networked transmission system may produce impacts that are difficult to project with great confidence, and the benefits may be distributed widely and across utility and political borders making a cost/benefit analysis far more challenging. Ideally, some of the benefits would be returned to support the transmission investment, but this feature may not be built in to the market design.

Managing congestion to avoid overloads or maintain security standards is generally an economic issue, and not an emergency or a reliability issue. Adding transmission capacity for relief of congestion removes or reduces constraints on the dispatch of resources, reducing production costs. Power systems operate around constraints every day, so investing money to relieve them is not generally an imperative obligation. Rather, it is an economic question of whether the societal benefits, i.e., the reduction in production costs and perhaps emissions,[13] outweigh the costs of the transmission project. If total benefits are not sufficient to cover the cost of the investment, then the optimal total-cost decision is to simply tolerate a bit of sub-optimality in operating cost. However, even if the societal value of congestion relief is sufficient, there remains a financial question of whether the prospective investor can actually capture enough of the benefits.

In a stand-alone vertically integrated utility, where all customers pay a proportional share of both transmission cost and energy cost, the costs and benefits naturally coincide with customers. However, many congestion issues are coincident with cross-border loop-flow problems, or issues encountered when formerly separate systems have joined together in joint dispatch or market operations. Investments in one system may produce benefits or costs in a neighboring system. This raises an interesting policy question for which a number of solutions have been devised: Who should be responsible for investing in congestion relief? How should they be compensated?

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[11] Note that each feeder is different, and the cost of effective controls varies with a number of factors.

[12] VVO/CVR may not impact all customers equally, though all customers may pay for a share of the system cost. Those customers that were near the end of the feeder may have had voltage in the lower part of the standard range all along, while those closest to the substation likely had voltages in the upper part of the range. So while VVO/CVR may not impact all customers equally, it may correct an imbalance of long standing by flattening the voltage profile so that the delivery voltages are more consistent all along the feeder.

[13] Dispatch is usually optimized on operator costs or bids. Unless emissions are priced-in, dispatch cost savings may not translate to emissions reductions.

Modeling to analyze and forecast the economics of congestion relief in large power systems is challenging. The actual impacts of congestion relief occur over a long period of time, during which conditions may change from current expectations. Congestion can be changed by shifts in the relative costs of gas and coal, or even regulatory drivers/incentives. Congestion can certainly be impacted by resource additions, which are being added rapidly on both the transmission and distribution systems in some regions. Further, it is challenging to estimate to whom the benefits of congestion relief actually flow. The benefits of congestion relief may be widely dispersed, and some market participants (particularly generators in a constrained importing region) may be worse off with congestion relief than before. A project with net social benefits could create an unjust outcome, asking one group of consumers to pay for benefits that flow elsewhere. The analytical challenges simply reflect uncertainty, which combined with market rules and regulatory constraints, translates into difficulties making projects work for investors.

The distribution of monetary benefits depends on the wholesale market design, the various boundaries of ownership, transmission rights, the link between wholesale and retail pricing, and many other factors. System and market rules vary in these dimensions, differing in how they distribute the benefits of congestion relief, and in how they provide incentives to encourage investment. In some systems, all grid users see the same prices for power, regardless of location. In other systems around the world, however, prices at the transmission level vary by location according to marginal cost to deliver power to or from each delivery point. The prices, which are usually public knowledge, expose information about congestion to market participants, and provide encouragement to market participants to invest in congestion relief. Locational pricing does not solve all of the problems associated with encouraging these investments, however. The general idea is that those who benefit from congestion relief should pay for it, but actually achieving this result is challenging. Perhaps it is the simplest case where central planners determine where investments should go, and the costs of transmission investments are charged to consumers broadly across the system, but the challenges in modeling and forecasting remain. Finally, pricing that does not reflect the differences in costs of delivering power to or from specific locations in the system does not encourage behaviors or investments that will mitigate congestion or prevent it from recurring.

The risks faced by investors in discretionary transmission investment for congestion relief are as varied as the market designs and rules. In fact, congestion relief is a good case in point to illustrate the impact of market design on the distribution of benefits among market participants. In any market design the transmission investor will be concerned about the earnings mechanism for the transmission project. That is, how will the revenues from the project be determined, and how risky are they? What risks will the transmission investor/owner carry? Regulators are concerned with the risks that their constituents carry, and ensuring that the benefits of investments accrue to those who are asked to pay for the investments. The organic bottom-up nature of system growth today intensifies all of these concerns for all market participants.

Conclusion

The landscape for transmission investment to meet grid needs varies greatly across the globe, from integrated regulated systems to locational market systems with independent transmitters and distributors.

Among entities with obligation to serve, investments in support of non-discretionary obligation service are likely to be accepted for cost recovery, and existing arrangements may be sufficient to assure that such investments are made. It is the beneficial projects that today are discretionary that require special attention. Economic cost/benefit analysis can help to determine which projects are societally beneficial, but economic analysis is insufficient to promote or to predict discretionary investments in the power system. Discretionary investments in new technology may have great benefits, but the benefits may not translate into financial returns for the investors. Investors everywhere face similar concerns with whether their investments will be recovered with sufficient returns over time. Their financial analyses examine the risks and rewards from their perspectives, examining the earnings mechanisms as well as regulatory conditions that may limit them. Nevertheless, the needs for investment in grid modernization are as great as ever, owing to the changing landscape of resource types and locations, driven from the bottom up by technology trends and economic forces, including subsidies and incentives. Smart-grid technologies that are discretionary today may become necessary in the future in order to continue providing society with reliable, affordable, and sustainable electricity in the face of high penetrations of local resources.