The Smart Grid Business Case

by

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Abstract

In the electricity industry, the development of a "smart grid" has risen to prominence as a nearly universal objective, with pilot programs and large-scale infrastructure investments occurring in every region of the country, among more than thirty utilities. These projects involve the adoption of new technologies that will enable a more effective monitoring of the electric system, improved reliability, and a new communications interface with customers, which in turn will make possible the introduction of new services and pricing programs that customers can use to more efficiently manage their electricity consumption. But an initial climate of general acceptance and even, in some cases, enthusiasm for this new wave of initiatives to modernize the electricity grid eventually gave way to a mixed reception, as stakeholders and regulators began to view these projects from a more critical perspective. Customers and regulators want to better understand the inherent value proposition underlying these investments in infrastructure: what the real costs are, who will benefit and in what manner, and when these benefits will materialize. Unfortunately, early attempts to develop coherent business cases – both for individual utilities and for the entire industry – resulted in a staggering range of outcomes, particularly with respect to the type and magnitude of benefits that were projected to occur. A clear need arose to develop rational and consistent guidelines for developing costs and benefits and correctly incorporating them into a business case. While much has been done – both by the industry itself and by the government – to address this need, weaknesses in the analytical approach still remain which continue to undermine results and contribute to a general inconsistency in outcomes. This paper will highlight some of the remaining issues, with suggestions on how to address them.

Introduction: Why a "Smart" Grid?

In the electricity industry, the term "smart grid" has become a focal point of discussion among utility electricity, regulators, entrepreneurs, and consumer advocates. A long-running industry joke is that, in spite of the plethora of presentations, webinars, publications, and even regulatory filings on the topic that have come out over the past several years, nobody is exactly sure what a "smart grid" actually is. The term seems to have first appeared in print in an article entitled "Toward A Smart Grid," by S. Massoud Amin and Bruce F. Wollenberg in *IEEE P&E* magazine in its 2005 September/October edition, but discussions about grid modernization had already been going on for years before publication of this article. In 2003, for example, a consortium named GridWise was formed to "promote, educate, and advocate for the adoption of" innovations in the electrical grid "that will achieve economic and environmental benefits for customers, communities and shareholders." And in 2004, the Electric

Power Research Institute (EPRI) published its "Intelligrid Architecture Framework", based upon a project of the same name, the purpose of which was to "assemble an integrated energy and communications system architecture to support a self-healing grid" and lay "the foundation for specifying and integrating advanced intelligent equipment across the electric industry as well as within individual companies." The U.S. Department of Energy also joined the fray, and in 2007 its National Energy Technology Laboratory (NETL) published a document entitled "A Vision for the Modern Grid." This document listed seven features that a modern grid should have:

1. **Self heals:** Automatically detects and responds to actual and emerging transmission and distribution problems. Focus is on prevention. Minimizes consumer impact.
2. **Motivates and includes the consumer:** Informed, involved and active consumers. Broad penetration of Demand Response.
3. **Resists attack:** Resilient to attack and natural disasters with rapid restoration capabilities.
4. **Provides power quality for 21st century needs:** Quality of power meets industry standards and consumer needs. PQ issues identified and resolved prior to manifestation. Various levels of PQ at various prices.
5. **Accommodates all generation and storage options:** Very large numbers of diverse distributed generation and storage devices deployed to complement the large generating plants. "Plug-and-play" convenience. Significantly more focus on and access to renewables.
6. **Enables markets:** Mature wholesale markets in place; well integrated nationwide and integrated with reliability coordinators. Retail markets flourishing where appropriate. Minimal transmission congestion and constraints.
7. **Optimizes assets and operates efficiently:** Greatly expanded sensing and measurement of grid conditions. Grid technologies deeply integrated with asset management process to most effectively manage assets and costs. Condition based maintenance.

In an effort to further clarify what a smart grid is, or should be, the Department of Energy has also listed the following "five fundamental technologies that will drive the Smart Grid":

- Integrated communications, connecting components to open architecture for real-time information and control, allowing every part of the grid to both 'talk' and 'listen'
- Sensing and measuring technologies, to support faster and more accurate response such as remote monitoring, time-of-use pricing, and demand side management
- Advanced components, to apply the latest research in superconductivity, storage, power electronics and diagnostics
- Advanced control methods, to monitor essential components, enabling rapid diagnosis and precise solutions appropriate to any event
- Improved interfaces and decision support, to amplify human decision-making, transforming grid operators and managers quite literally into visionaries when it comes to seeing into their systems

While definitions such as these have helped to create a clearer picture of what the smart grid is, or could become, they have fallen short of creating a definitive "roadmap" on how to "get from here to there".

But it would probably be impossible to create such a definitive roadmap. Each regional electricity system is unique, with different mixes of residential, commercial, and industrial customers, different generation portfolios, and even radically different underlying market structures. And each regional electrical system has a grid which is more or less "modern" or "smart" by degrees. Hence, any particular system will be starting from a unique state, and, based on the demographic characteristics of its customers, the type and location of its generation sources, and its market structure, its energy providers will adopt a unique subset of technologies to modernize the grid.

The particular choices made, however, will be driven by an assessment of costs and benefits. All electricity stakeholders, be they energy suppliers, distributors, regulators, customers (and consumer advocates), or even entrepreneurs, will only support those choices that promise ultimate benefits that exceed the costs to invest in them. There are challenges to performing such an assessment, not the least of which stems from the fact that multiple stakeholders are involved. Each class of stakeholder will bear some share of responsibility (and risk) for investing in grid modernization, and will receive a unique stream of benefits. Benefits for one class of stakeholders may actually be losses for another. And many long-term benefits will be contingent on future events, such as widespread adoption of electric vehicles, or active customer participation in demand response enabled by "smart" meters and real-time pricing. Table 1 provides a summary of the benefits and risks which grid modernization presents to major classes of stakeholders.

Benefits may also be difficult to quantify, which will complicate the business case. While it may be possible to estimate a value to customers of increased reliability, for example, it is a much more abstract proposition to assign a value to improved customer service (e.g., reduced call waiting times). General impacts on the economy, such as job creation, are also difficult to quantify, because investments may have both positive and negative consequences. While it is true that infrastructure investments, for example, will have direct positive impacts on the economy, there will also be negative effects resulting from the electricity rate increases that will be required to fund them, as electricity consumers will have less discretionary income to spend elsewhere in the economy. Conversely, if a new technology produces operational savings by making it possible to reduce staff, then rate reductions to consumers will have a positive impact on the economy because they will have more discretionary income to spend, but the workforce reductions will have a negative impact.

This difficulty in consistently identifying and quantifying benefits has already become apparent in the business case studies that have already been performed. In 2003-2004, three industry-wide benefits assessments for the smart grid were conducted: by the Pacific Northwest National Laboratory (Kannberg, et. al., 2003), the RAND Corporation (Baer, et. al., 2004), and the Electric Power Research Institute (EPRI, July 2004). The resulting estimates of total benefits ranged from $75 billion to $802 billion: a factor of over 10 to 1. While some of this range can be explained by a difference in discount rates used, it is mainly the result of a wide disparity in the set of benefits that were identified to be included in the analysis, and the methods used to quantify the benefits which were included. More recent system-wide studies indicate that this disparity continues to exist. In 2008, the Edison Electric Institute commissioned a consultant, the Shpigler Group, to develop cost and benefit estimates for a typical smart grid system in a utility with one million meters (The Shpigler Group, 2008). Extrapolating the results of this analysis to the industry in general suggests that the cost of implementing the smart grid for the entire U.S. electric system would be about $48 billion dollars over a ten-year period, and the benefits would be $63 billion. Extrapolating these results even further, to a twenty-year horizon, suggests that total costs would be about $84 billion and total benefits $104 billion. In 2011, EPRI performed an updated cost-benefit analysis of the smart grid (EPRI, 2011) and concluded that total investment expenditures would range from $338 billion - $476 billion over a 20-year period, and total benefits would range from $1,294 billion to $2,028 billion. (Note: the recent EPRI study did not use a discount rate, but merely accumulated the annual costs in constant 2010 dollars. Assuming that costs and benefits occurred uniformly throughout the 20-year period, then the discounted range of costs at 5% would be $211 billion to $297 billion, and the discounted range of benefits would be $806 billion to $1,376 billion.) A comparative summary of these studies is

Table 1: Potential Benefits and Risks for Key Smart Grid Stakeholders		
Market Participants	**Payoffs / Desired Benefits**	**Risks / Potential Losses**
Residential Customers / Small Business Customers	• Simplicity / Transparency • Little Time Required to Manage Service • Reliable Electricity Supply • Stable Rates – No Sudden Hikes • Long-Term Rate Reduction	• Rate Offerings Incomprehensible • High Cost in Time and Technical Support to Manage Service • Sudden Hike in Electric Rates to Cover Costs of Smart Grid • No Long-Term Savings
Large Business Customers	• Menu of Service Offerings from One or More Sources to Tailor Desired Levels of Reliability and Power Quality • Control Over Pricing o Negotiated Rates o Real-Time Pricing o Supplier Choice	• Few if Any Alternative Pricing Options: the Main Control Over Price is the Threat of Business Failure or Migration • Prices Rise Due to Smart Grid Costs and/or Flatter Load Profile of Smaller Customers • Decline in Power Quality/Reliability
Regulators	• Extended Incumbency • Positive Public Notice for Advancement of Societal Goals • Expansion of Jurisdictional Authority	• Negative Public Reaction Due to Perceived Consequences of Regulatory Activity (e.g., “Rate Shock”, Customer Confusion, Electric System Failure) • Loss of Jurisdiction
Regulated Utilities - Shareholders	• Allowed Return on New Investments in Infrastructure • New Earnings Opportunities in Regulated Services Through Incentive-Based Regulation • New Earnings Opportunities in Unregulated Sector	• Lost Earnings Due to Regulatory Lag / Disallowances • Lost Revenue Due to Competition • Losses from Failed Enterprises in Unregulated Sector
Technology Developers	• High Return from Investment in and Development of New Technology	• Insufficient Recovery of R&D Investment Due to Lack of Adoption and/or Slow Payback
Independent Energy Services Providers	• Captured Revenue from Incumbent Energy Providers	• Losses from Failed Attempts at Competition

shown in Table 2. As can be seen in the table, estimates for both costs and benefits continue to range widely, but the range is most conspicuously broad in the benefits estimates.

Table 2: Summary of Industry-Wide Smart Grid Cost-Benefit Studies					
Study	**Year**	**Time Frame**	**NPV of Costs**	**NPV of Benefits**	**Discount Rate**
PNNL	2003	20 Years	N/A	$ 75 billion	6%
RAND	2004	20 Years	N/A	$ 81 billion $ 110 billion	10% 6%
EPRI	2004	20 Years	$165 billion	$638 billion - $802 billion	5%
Shpigler Group	2008	10 Years 20 Years 20 Years	$ 48 billion $ 84 billion $ 92 billion	$ 63 billion $ 104 billion $ 117 billion	8% 6% 5%
EPRI	2011	20 Years	$338 billion - $476 billion	$1,294 billion - $2,208 billion	None

Variances such as these in cost and benefit estimation at the industry level are even more pronounced among individual business cases prepared by utilities and advocates of smart grid investments. A recent summary prepared for the National Energy Technology Laboratory of twenty-three utility state regulatory filings which included smart grid business cases indicated that benefit-cost ratios produced in these cases ranged from less than 1-to-1 to over 17-to-1 (NETL, 2011). This wide range was driven by a number of factors, including the choice of particular smart grid technologies to invest in and the method used (if any) of discounting future streams of costs and benefits. But another significant factor driving much of the differences was the specific types of benefits that were identified as associated with each smart grid technology, and how these were estimated.

As more and more utilities take the first steps in implementing a smart grid system, preparing business cases and presenting them to their local regulator commissions, regulators, in turn, are beginning to take a harder look at the real costs and benefits of implementing these systems. Particularly now, in the face of a slow, painful recovery from the worst economic recession since the Great Depression, with unemployment projected to remain at close to 10% for years to come, regulators are sensitive to the impacts of electricity rate increases on their constituents. How will ratepayers benefit from investment in the smart grid, and when will these benefits be realized? Wide variances in business case estimates only serve to increase skepticism among regulators about the credibility of their results. To respond to this regulatory skepticism, utilities must adopt a high standard of rigor in preparing them.

Business Case General Principles

The development of a plausible business case is contingent upon a number of factors. Principle among these is that a set of generally accepted principles must be adopted for preparing the case. The Electric Power Research Institute proposed one such set of such principles in its *Methodological Approach for Estimating the Benefits and Cost of Smart Grid Demonstration Projects* (EPRI, 2010). The approach, which would eventually serve as one of the guides for the U.S. Department of Energy's own method for evaluating the benefits and costs of smart grid projects that had received federal stimulus grants, consists of 10 steps:

1. Itemize the particular infrastructure asset investments under consideration and the general goals which each is supposed to support
2. For each asset, identify the functions that it will potentially perform
3. For each function, specify in more detail the specific activities or services that will be provided
4. Using Step 3 as a guide, map each function onto a standardized set of benefit types
5. Establish a base case, i.e., a baseline representing future cost and revenue streams which would be expected to occur if the project was not undertaken
6. Determine necessary data requirements to enable measuring and tracking of benefits
7. Estimate the incremental benefits (i.e., the benefits that occur or are projected to occur, compared to the base case)
8. Monetize the benefits: assign monetary values to each class of benefit
9. Estimate the relevant incremental costs to deploy the project
10. Compare incremental costs to incremental benefits, calculating the incremental benefit year-by-year, and then computing the net present value with the use of a discount rate

In accordance with this methodology, the EPRI document identifies 19 classes of assets and maps these onto 13 types of functions, and then maps these functions in turn onto 22 benefits, grouped broadly into the following categories:

1. Improved Asset Utilization (including deferred generation capital savings)
2. Transmission and Distribution Capital Savings
3. Transmission and Distribution O&M Savings
4. Theft Reduction
5. Energy Efficiency (i.e., reduced electricity losses)
6. Electricity Cost Savings
7. Reduced Power Interruptions
8. Improved Power Quality
9. Reduced Air Emissions
10. Improved National Security (from a lower dependence on imported oil, and fewer wide-scale blackouts)

The general methodology developed by EPRI does much in the way of establishing a standardized, defensible approach to measuring and/or projecting the costs and benefits of smart grid infrastructure investments. Still, even with the proper application of the EPRI approach, there exist hazards which could undermine the establishment of a sound business case. These will be addressed in the remaining sections of this paper.

Benefits and Costs

Business case benefits must meet three criteria: 1) they must be quantifiable, 2) they must be capable of measurement and verification, and 3) they must be tied to specific classes of beneficiaries. This last requirement can be complicated, because a single benefit stream may flow to different classes of beneficiaries simultaneously, or move from one class to another during the life of the asset. As an example, consider an asset that is projected to produce savings in O&M expenditures after it is installed. These savings will be a benefit to the ratepayer if they are passed into rates immediately at the time the asset goes into the rate base. On the other hand, if the savings are not passed into rates until after they are actually observed, and even then only after the next rate case, then several years might elapse during which utility O&M expenses are reduced, but rates are not lowered to reflect this. Within this period of time, the savings constitute a benefit to the shareholder, because they will flow through to net earnings. A third scenario might be that the savings are shared between the ratepayer and the shareholder in the form of an automatic rate adjustment, perhaps involving performance benchmarks (i.e., if a targeted level of savings is exceeded, then a share of this savings is retained as earnings, or conversely if the target is not met, then part of the loss is borne by the shareholder). As another example, consider the benefit of greenhouse gas reductions that are expected to arise from certain investments. If utilities are currently not paying a penalty for greenhouse gas reductions (e.g., through something like a carbon tax) which is borne by ratepayers, then this benefit is not really flowing through to the ratepayer in the form of tangible savings at all. Instead, it is a "societal benefit", enjoyed by the population at large, whether they are electric ratepayers or not. Greenhouse gas reductions will only produce dollar savings to the electric ratepayer if a climate policy is in effect which has imposed a tax on these emissions. Table 3 illustrates some common categories of benefits, and how these can flow to different or multiple beneficiaries under different circumstances.

With benefits, there is an additional complication: it is less than certain that they will be realized, or at least realized at projected levels. This is due in part to the fact that many smart grid infrastructure investments consist of new or developing technologies that haven't been around long enough to enable reliable assessments of their impacts and performance, and that may be more prone to operational difficulties because of their relative novelty. Many anticipated benefits are also contingent upon the presence of other factors in the system or anticipated future changes. Any benefits that arise due to anticipated changes in customer behavior in particular, will be particularly tenuous. A prime example is demand response, in which advanced metering technology makes it possible for customers to respond to pricing signals that are more reflective of the actual hourly cost of electricity. System benefits arising from this behavior include the ability to put off having to build new generation and/or transmission facilities, because peak demand will be reduced as customers cut back on electricity usage during these hours, when wholesale electricity costs tend to be high. However, if customers are not as sensitive to changing prices as anticipated, or if they opt not to participate in such pricing programs altogether, then the level of demand response may be much less than had been anticipated, and consequently actual benefits associated with demand response will be much less than projected. A proper business case must account for uncertainties in benefits by either adjusting their forecasted magnitudes based on expected probabilities of occurrence, or developing sensitivity cases that correspond to alternative outcomes (e.g., low, middle, and high levels of demand response).

Finally, to prevent the risk of double-counting benefits, any particular business case should be oriented to one distinct class of beneficiaries, whether that be the electricity consumer, the regulated utility shareholder, or even society at large. After all, each of these classes of beneficiaries will be called upon to support grid modernization in a different way, bearing a set of costs and risks unique to them, and so to determine if these costs and risks are justified, it is only proper that the benefits specifically flowing to each particular class be the ones that are included in their respective analyses.

Table 3: Common Smart Grid Benefits and Who Receives Them

	Consumer	Utility (Shareholder)	Society
Deferred Generation / Transmission Capacity	Gain (from avoided rate increases)	Loss (from return on deferred investments)	
Operational Savings (e.g., meter reading, outage detection, call center)	Gain (but only after savings are passed through to ratepayers in the next rate case)	Gain (but only before savings are passed through to ratepayers in next rate case, or if savings achieved beyond some benchmark level are awarded to shareholders as a performance incentive)	Job impacts: • Positive from higher shareholder earnings and/or ratepayers having more money to spend • Negative from utility employment reductions
Outage Reduction	Gain from greater reliability		Collateral economic benefits from a more reliable electric system
Energy savings from demand response	Net gain in consumer surplus	Net loss in producer surplus (from reduced energy sales)	
CO_2 Emissions Reductions	No monetary benefit unless there is a price on emissions due to climate policy		General benefit from improvement to environment

AMI

Based on its summary of twenty-three utility state regulatory filings involving smart grid investment, the report prepared for the National Energy Technology Laboratory (NETL, 2011) concluded that advanced metering infrastructure (AMI) was the most common smart grid technology being adopted by utilities, with 74% including it in their filings, and 50% identifying it as the predominant project. The prevalence of AMI in these cases, the report explains, is due to the fact that is "foundational for the implementation of other technologies", including: "smart appliances" and programmable communicating thermostats in the home, the management of plug-in hybrid electric vehicles, and the support of systems that will enable "self-healing" of the electrical grid. But the "smart meter" has come under intense regulatory scrutiny in the wake of a rash of unexpected public opposition in California and other states (England and VandenBerg, 2010, and Zeller, 2010), making it more imperative than ever that the business cases presented for these technologies are based upon sound economic principles. Because the business case for AMI infrastructure is also representative of those for other smart grid technologies, both in the manner of its preparation and in the method that costs and benefits must be treated, the AMI business case will be used as an example for the remainder of this paper.

Advanced metering infrastructure provides a number of direct benefits, the principal one being that it eliminates the need for manual reading of electric meters for billing and usage monitoring purposes. Consequently, savings are realized by a reduction in the number of meter readers employed by the company, by reduced vehicle transportation expenses, and even as a result of savings in the call center as both the number of and duration of billing complaint calls decline. If the meters are also equipped with the capability to connect or disconnect electricity service remotely, then further savings are realized by facilitating shut-offs for non-payment, and speeding up the process of connecting new customers or reconnecting old ones. Revenue losses from energy theft and faulty mechanical meters will be reduced, and the utility's monthly cash flow can improve since there will be a reduced lag between the end of a customer's billing period and the receipt of the customer's usage information. Finally, automated meters enable the tracking of hourly customer usage, and this in turn makes possible the introduction of time-of-use pricing programs, in which customers are charged for electricity based upon time-varying rates that are more reflective of the actual cost incurred by the local distribution company for purchasing and/or generating that electricity. These rates encourage customers to scale back their usage during times of peak demand, when electricity prices tend to be high, and shift all or part of that curtailed load to other hours when the electricity is less expensive to provide. This in turn actually serves to attenuate future electricity rate increases, since a reduced peak load defers the need for generation capacity. It also tends to provide a net benefit to consumers as a result of their purchasing more electricity at reduced rates during off-peak hours.

Table 4 summarizes the principal cost and benefit elements of AMI, with some typical estimates, based upon actual utility business cases for AMI (NETL, 2011) and the hypothetical business case prepared by the Shpigler Group (Shpigler, 2008). (As with the Shpigler study, the example below assumes a utility with 1 million meters, of which approximately 87% are residential customers, 13% are commercial customers, and less than 1% – about 4 thousand – are industrial customers.) In the actual business cases developed and filed by utilities, there has been a significant range in some of the estimates categories, particularly with respect to O&M savings. And while each of the categories listed in the table are the ones that tend to appear most frequently in the business cases, other categories are included in one or more of these cases as well, such as savings in training expenses or in load research. The benefits in the table are all expressed in terms of a savings per meter, but this is merely for consistency. The method of calculation for each benefit may be based on assumptions that are not explicitly linked to meter counts. For example, vehicle savings is derived based upon the assumed number of vehicles used each year for meter reading, the estimated number of miles driven by each vehicle, and an estimated cost of fueling them. Both the Shpigler paper and the EPRI manual for benefit/cost estimation (EPRI 2010) provide examples and/or suggestions on how to derive estimates for each cost and benefit category. (Note that because of the incremental nature of the business case, revenue for salvaging the old meters only counts as an incremental benefit to the extent that each particular meter is salvaged prior to its planned time of expiration in the base case. The figure in the table represents a weighted average of this incremental benefit per meter.)

Table 4: AMI Costs and Benefits

Costs	Benefits
Meters (Installed Cost, including Labor) • Residential ($60/meter) • Commercial ($150/meter) • Industrial ($290/meter)	Reduced Meter Reading O&M • Labor and Vehicles ($9.14/meter/year) • Connect/Disconnect ($5.40/meter/year) Salvage ($1.25 per meter replaced)
Remote Disconnect Collars ($130/meter)	Reduced Meter Error Losses ($1.02/meter/year)
Meter Data Backhaul ($5,000,000)	Reduction in Energy Theft ($2.58/meter/year)
AMI System Integration ($1,000,000)	Improved Cash Flow ($1.28/meter/year)
Incremental Operating Cost ($1.20/meter/year)	Billing and Call Center Savings ($1.85/meter/year)
Demand Side Management Software ($1,000,000)	Reduced CO_2 Emissions (see text)
Marketing for New DSM Rates ($21,000)	Deferred Generation Capacity (see text)
Loss in Producer Surplus from DSM (see text)	Gain in Consumer Surplus from DSM (see text)

Most of the costs and benefits listed in Table 4 will be of direct relevance to the local distribution company and their customers on whose behalf investments in AMI infrastructure are being made. But the application in a business case of these costs and benefits will be quite different from the perspective of the utility vs. that of the ratepayer. For the utility (or rather, its shareholders), the relevant benefits will be the allowed return on the capital investments made, and those cost savings and/or revenue increases that are not passed through to the ratepayer, either due to regulatory lag or because of incentive-based regulations that allow a pass-through of part of the savings if they exceed a pre-defined performance benchmark. For the ratepayer, the relevant business case will simply involve the impact on rates over time, with the infrastructure investments contributing to a rate increase, and the operational savings contributing to an immediate or eventual decline in rates, based on when the savings are actually passed through to rates. (There may also be other benefits included in the ratepayer business case, such as the value of improved reliability or reduced call waiting times, but the assignment of value to benefits such as these will be contingent on a method of quantifying them that is mutually acceptable to the utility and the customer – or rather the regulator who is adjudicating the rate case on the customer's behalf.) It is important to note as well that when conducting a net present value analysis, the choice of a suitable discount rate will depend on the specific stakeholder for whom the business case is being prepared. As suggested in a document by the Environmental Protection Agency which provides guidelines for conducting a different type of policy evaluation (energy efficiency programs, see EPA, 2008), an appropriate discount rate for the household (ratepayer) would be the consumer lending rate, while for businesses and utilities, a more suitable rate would be that entity's particular weighted average cost of capital, and for society in general, the social discount rate.

A reduction in greenhouse gas emissions is listed as one of the benefits in Table 4, but no value is assigned. (Such a reduction could occur as a result of, for example, the reduced use of vehicles for reading meters.) As discussed earlier in this paper, unless a national or regional climate policy is in place which actually imposes a cost on these emissions, then there is no tangible benefit to the utility shareholder or to the ratepayer for reducing them. If such a cost is imposed through climate legislation, then the savings realized from reducing emissions would be treated just like the other savings quantified in the table, in that their inclusion as benefits in either the shareholder's or the ratepayer's business case will depend on when the savings actually flow through to either party. If no climate policy is in place, there is of course still a benefit to reducing greenhouse gas emissions, but assigning a value to it, and then determining who should pay for it, is problematic. It is really, at this stage, a "societal" benefit, flowing through not just to shareholders and ratepayers but to everyone. As to its value, many studies have developed estimates of the "social cost of carbon", which represents the approximate marginal value to society of reducing one ton of CO_2 emissions. (For a meta-analysis of these studies see Tol, 2008, and for a recent attempt to develop the social cost of carbon for government policy studies, see IWGSCC, 2010.) This value could be applied as a benefit when evaluating a business case from the perspective of society as a whole. (In the one-million-meter case study in Shpigler, 2010, total annual benefits attributed to CO_2 reductions resulting from the reduced use of vehicles for meter reading, assuming a social cost of carbon of $20 per ton of CO2, amount to about $6,800.) The question then, of course, is how "society" would pay for such a benefit. An obvious way would be through a direct tax, the revenues of which would be used to subsidize investment in the relevant smart grid infrastructure. This form of government-funded subsidization in fact has already occurred, but not as the direct consequence of a business case indicating that society as a whole should bear part of the cost burden for grid modernization. The subsidies occurred as a result of the American Recovery and Reinvestment Act of 2009, because a part of the funds that made up the stimulus grant to revive the economy were directed to the electricity industry to support investment in smart grid infrastructure. (Such grants, when they occur, should be appropriately accounted for in both the shareholder and ratepayer business cases.)

A benefit arising from AMI and the dynamic pricing programs that they make possible is the deferral of necessary capacity additions in generation (and possibly transmission and distribution as well), as time-of-use pricing reduces load during periods of high electricity demand, when the market price of electricity is high. The standard utility rate shields customers from the higher hourly prices of electricity generation during these periods, because the rate structure does not reflect actual hourly prices. The monthly electricity bill is calculated based upon the average energy charge which occurred during the entire billing period (and in fact this is not even really the case, since rates are based upon the expected average energy charge for the period). Customers therefore have no incentive to curtail usage during periods of high demand, and, in fact, with the typical declining block electricity rate, in which the per-kilowatt-hour charge of electricity falls with higher usage, an incentive exists to use more electricity, at all times of the year.

When peak demand is reduced as a result of demand reductions in response to higher on-peak prices, there will be a reduced requirement for future electricity generation capacity, and the lower requirements will translate into lower future electricity costs than would have occurred had the original planned expansion actually occurred. Quantifying the benefits of this reduced capacity requirement depends on the type of market structure within which the utility is operating. In traditional regulated markets, in which generation, transmission, and distribution are provided as an integrated service by a single, regulated utility, the capacity savings will be estimated by comparing the timing and costs of new capacity additions in the base case vs. an alternate case in which AMI infrastructure and dynamic pricing programs have been put in place. In this alternate case, capacity additions will occur later in time and/or will be on a smaller scale, relative to the base case, and hence will mitigate future rate increases. Many companies, rather than actually comparing alternative cases for planned generation capacity additions and developing incremental costs and benefits based on these, have used a proxy estimate for the value of deferred generation, usually expressed in terms of dollars per kilowatt of capacity reduced. The proxy value used in actual business cases has ranged from \$50/kW-Year - \$100/kW-Year. In restructured electricity markets such as PJM and ISO New England, where electric generation has been “unbundled” from transmission and distribution, power is purchased by local distribution companies in a competitive wholesale market. The value of electricity capacity in a system like these is reflected in the electricity capacity markets, where local distribution companies purchase electricity capacity (in order to ensure access to electricity supply during times of high demand) to supplement their purchases of actual electricity. Hence, the value of reduced peak demand among their customers can be directly calculated based upon the estimated reduction of total capacity costs in that market. Regardless of the market structure, therefore, the result of demand side management programs such as dynamic pricing will be to reduce the magnitude of future electric rate increases and/or reduce the level of present rates, which constitutes an ultimate tangible benefit to the ratepayer.

Assessing avoided transmission capital costs is a little more difficult, and is often estimated by observing the historical relationship between transmission and generation capital investment, and, based on these observations, estimating an add factor (e.g., 10%) which can be applied to the generation number to cover transmission as well. While the specific calculation number for transmission savings must therefore based on some tenuous assumptions, the underlying argument for including some kind of savings estimate for avoided transmission capital costs is also sound.

There is an additional benefit that is often attributed to demand side management, and this is the net energy savings that customers obtain by reducing their load during peak hours, when electricity rates will be higher if dynamic pricing programs have been implemented, and shifting all or part of this load to off-peak hours, when electricity prices will be lower with dynamic rates. However, the determination of this benefit is based upon a flawed economic conception of consumer welfare, and generally overstates the actual benefit to ratepayers of actively managing their load. The next section will describe the basis of this economic fallacy, and describe a more appropriate method for estimating the benefit of demand-side management.

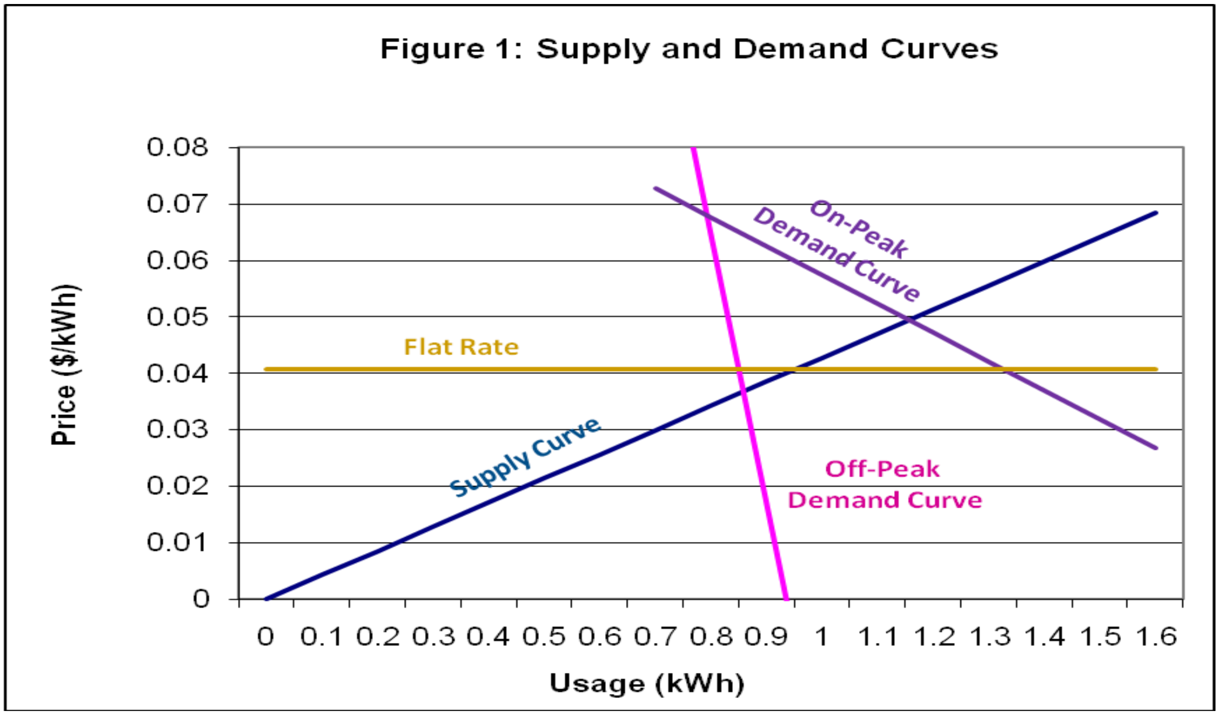
Savings vs. Benefits: The Need for a Consumer Surplus Approach

To understand the flaw in the net savings approach, consider the following example: Suppose that during the workweek, twice every morning, I visit my local coffee shop, and purchase a cup of coffee for $2 a cup. My expenditures for coffee each week then total $20.00, and I drink ten cups of coffee a week. But now suppose that – in order to manage the long lines due to heavy morning demand – the coffee shop raises the price of coffee to $3.00 per cup. Deciding that $30 a week is too much to spend on coffee, I cut my purchases in half, so that now I am only spending $15.00 in total each week. Now imagine how I would feel if this coffee shop starts to boast that it has done me (and other customers who behave in the same manner as I did) a big favor, by reducing my coffee expenditures by 25% - labeling these as “savings”! Am I better off as a result of this new arrangement, just because I am spending 25% less on coffee? I (and most persons who made the same choice as I did) would not think so. We’re spending less, but we’re getting much less of what we enjoyed and valued as well.

Defenders of the savings approach when applied to electricity sales might counter that the demand reductions occurring due to real-time electricity pricing are not necessarily lost electricity sales – all or part of them could be sales that just occur now at a different time of day (i.e., off-peak). So let’s take the coffee example one further step. Suppose that my local coffee shop decides to reduce the price of coffee in the evening hours, when demand slackens and its resources are underutilized, from $2.00 to $1.00. It then proudly announces that customers like me can still spend the same amount of money in total each week on coffee: all we need to do is change our buying patterns so that we buy one cup of coffee in the morning and one cup of coffee in the evening. Even better, they argue, if I choose to buy more coffee in the evening than in the morning, then I will be able to consume just as much as before and actually still save money. Am I as well off now as I was before? Hardly. While technically this is all true, I will not see much value in getting that caffeine jolt at 8:00 in the evening. I could be getting just as much coffee, and even spending less for it, but life just doesn’t seem as good to me.

Similarly, when discussing (and quantifying) the potential consumer benefits that could accrue from demand response, it is not correct to use dollar savings as a contributing indicator of these benefits. To better appreciate the irrelevance of this measure, it will be helpful to revisit that bane of the introductory economics courses, the consumer surplus graph. Consider the following hypothetical example: An electric utility has been offering a standard flat rate energy charge for electricity of 4.1 cents per kWh. (Note that these rates do not include transmission, distribution, and customer service costs, all or part of which might appear in the customer’s bill as a fixed monthly fee.) For simplicity’s sake, we assume that the utility’s residential customers have exhibited two distinct consumption patterns: an on-peak usage averaging 1.33 kWh from the hours of 2:00 PM to 7:00 PM on weekdays, and an off-peak usage averaging 0.85 kWh during all other times. At these rates, the customer’s total energy charges for the year are $329.

Now the utility would like to introduce a time-of-use rate. Based upon load research, it has estimated that during peak hours, customer usage is price sensitive, with a price elasticity of -0.6 (i.e., for every 1% increase in the energy price, usage would decline by 0.6%). During the off-peak hours, however, customer load is relatively insensitive to price, with an elasticity of -0.1. This should be the case, as consumption during the off-peak hours will tend to be dominated by electrical appliances that run constantly and/or are considered necessities, such as computers and lighting. With similar information derived about the sensitivity of electricity supply to price, the utility is able to derive supply and demand curves, as illustrated in Figure 1. (For simplicity, all supply and demand curves are assumed to be straight lines, with the assumed elasticities occurring in the regions where price changes will be occurring due to adoption of the time-of-use rate.)



The utility introduces a time-of-use tariff with a peak energy rate of 4.9 cents/kWh and an off-peak rate of 3.7 cents/kWh. When the new rate is instituted, we see a 13% drop in peak-time usage from 1.33 kW to 1.16 kW during each hour of the peak. Unlike the coffee example, this change to higher pricing during the peak will not result in a net savings. In each hour of the peak, the consumer will be paying an incremental amount of:

(1.33 kWh x $.041/kWh) – (1.16 kWh x $.049/kWh) = $0.0031,

which, with 1,304 hours of peak demand in each year, totals to $4.10. However, this extra cost is more than made up for during the off-peak hours, where savings will occur:

(0.85 kWh x $.041/kWh) – (0.86 kWh x $.037/kWh) = ($0.0031).

Although the hourly savings off-peak matches the extra hourly cost that is incurred on-peak, there are many more off-peak hours in the year than on-peak hours, totaling, in this example, 7,456. Total off-peak savings will then be $23.10, leading to a net total annual savings of $19.00 per year. But is this the actual net benefit to the consumer which would be obtained by switching from flat to peak/off-peak pricing? A closer look at what is happening, in terms of change in consumer surplus, will tell the real story.

Figure 2 illustrates what is happening on-peak. Customers are using less but paying more on a per kilowatt-hour basis. As indicated in the earlier calculation, in spite of the reduced usage, the higher rate will cause customers to pay more in total during the on-peak period with the new rate. In terms of the labeled rectangles in Figure 2, this net change in expenditures is equivalent to:

(A + B) - (B + D) = A-D,

where Rectangle A is the incremental expenditure from purchasing electricity at the new, higher rate, while Rectangle D is the change in expenditures associated with the change in usage. The problem with this calculation is that it is not truly measuring the change in net consumer surplus. Rectangle A should be included, as it was in the savings calculation, because paying a higher price for the electricity that is still being purchased is a direct loss. But the impact of reduced electricity usage on net consumer surplus is trickier. The total value, from the consumer perspective, of the electricity no longer being purchased is equivalent to the area under the demand curve, bounded by the old and new usage levels, which is represented as the sum of Triangle C and Rectangle D. Foregoing these electricity sales does produce a cost savings, equivalent to Rectangle D, but this cost savings is exceeded by the total value of the electricity no longer consumed:

$$D - (C + D) = -C.$$

Hence, the actual loss, from the consumer perspective, is not equivalent to the net increase in expenditure (A-D), but rather the increased expenditure for electricity still being consumed (Rectangle A) plus the net loss in value of the electricity no longer being consumed (Triangle C).

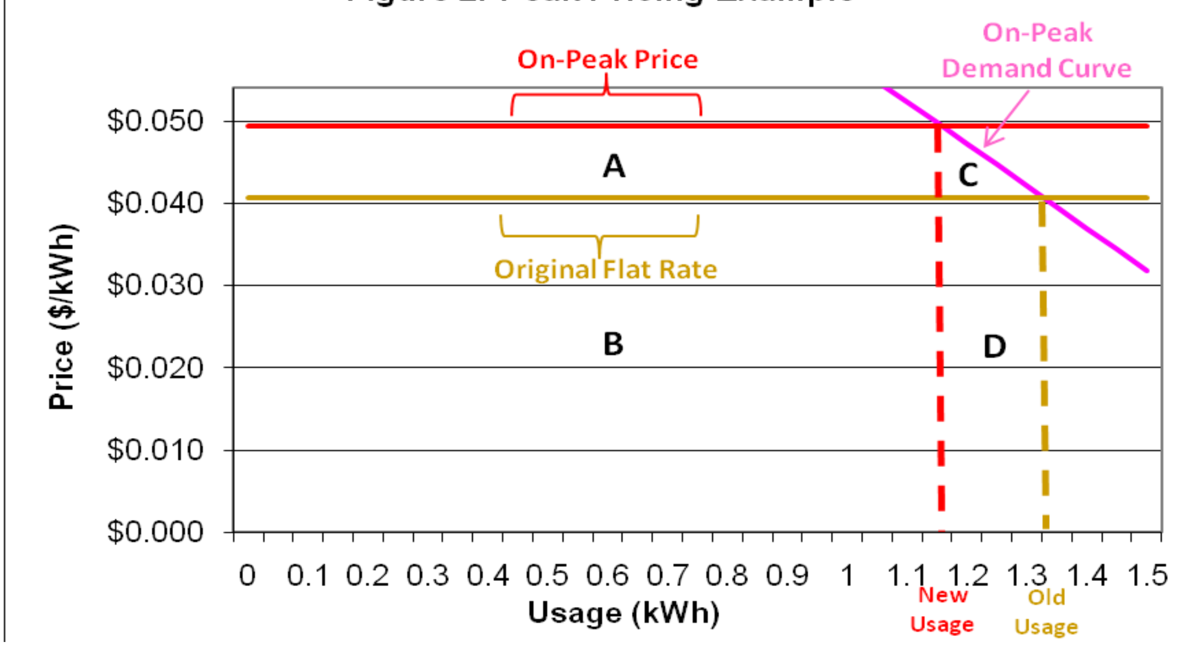


Figure 2: Peak Pricing Example

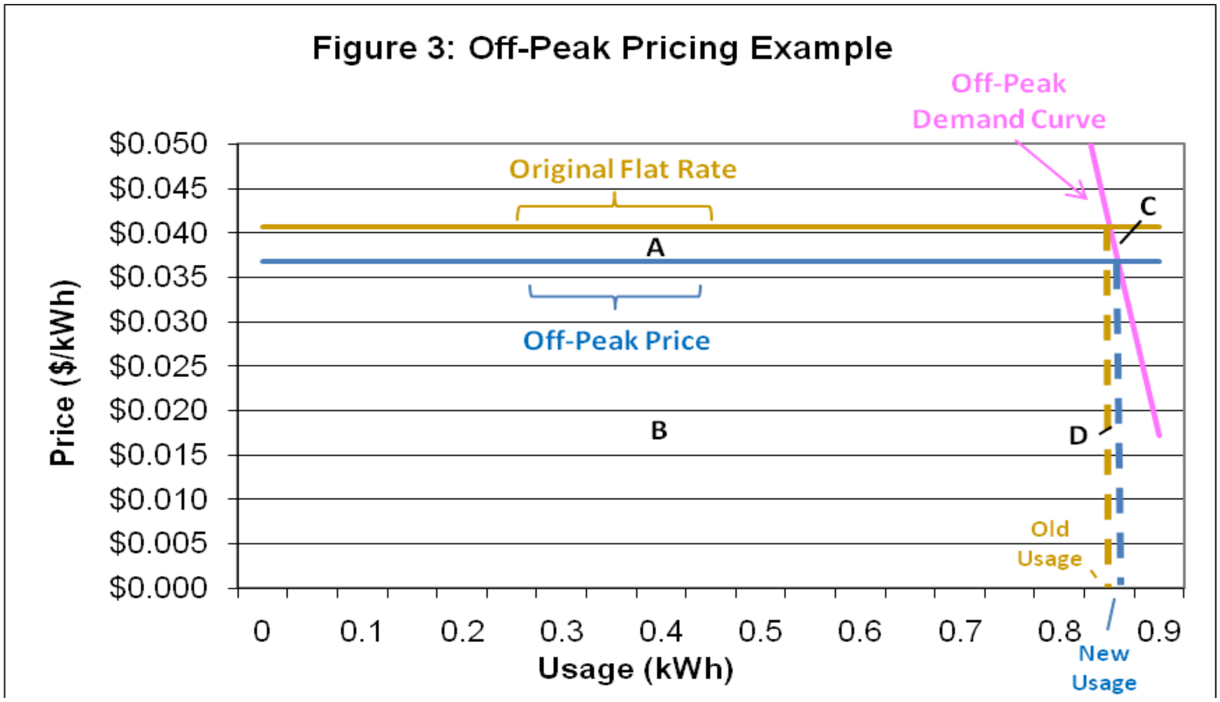
In numeric terms the net consumer surplus calculation is represented as:

(Old Price – New Price) x (New Hourly Consumption) [Rectangle A]
\+ ½ (Old Price – New Price) x (Change in Consumption) [Triangle C]

($0.041/kWh - $0.049/kWh) x (1.16 kWh)
\+ ½ x ($0.041/kWh - $0.049/kWh) x (1.33 kWh – 1.16 kWh)

= -$0.0108

When multiplied by the total number of on-peak hours (1,304), the net loss in consumer surplus totals $14.10, which is much higher than what the savings calculation suggested for this period.



However, as with the savings calculation, there is a positive change to consumer surplus in the off-peak hours, where the electricity rate has been lowered (Figure 3). According to the savings calculation, the net benefit here is represented by:

(A + B) – (B + D) = (A – D)

where Rectangle A represents the savings obtained by using the original level of off-peak electricity usage at a lower rate, and Rectangle D represents the extra expenditures arising from buying more electricity because of the rate change. But again, net consumer surplus calculations tell a different story. As with the on-peak case, both methods of calculation are in agreement that the savings which stem from a price change represent a direct change in consumer surplus. But unlike the on-peak case, now more electricity is being used as compared to when flat pricing was used, because of the reduced off-peak rate. The total value of this electricity, as before, is equivalent to the area under the demand curve, bounded by the old and new usage levels, which is represented as the sum of Triangle C and Rectangle D. While the consumer is spending more to make these additional purchases, the incremental expenditure is exceeded by the value of the electricity, yielding a net benefit:

(C + D) – D = C,

and so this time the net change in consumer surplus is equivalent to the sum of Rectangle A (the savings from purchasing the original off-peak level of electricity at a new, lower price) and Triangle C (the net benefit of buying additional electricity at this lower price).

In numeric terms, this net consumer surplus calculation is represented as:

	(Old Price – New Price) x (Old Hourly Consumption)	[Rectangle A]
+	½ (Old Price – New Price) x (Change in Consumption)	[Triangle C]

($0.041/kWh - $0.037/kWh) x (0.85 kWh)

+ ½ x ($0.041/kWh - $0.037/kWh) x (0.86 kWh – 0.85 kWh)

= $0.0034

When multiplied by the total of off-peak hours, the net gain in consumer surplus for the year is $25.51.

Combining the net loss in consumer surplus which is incurred in the on-peak period with the net gain in consumer surplus incurred in the off-peak period yields a total of $11.41. So while there is a net benefit from a consumer perspective in using a time-of-day pricing mechanism, this net benefit is not as high as a simple savings calculation would indicate. In fact, in this example the savings calculation overstated the benefit by over 66%. While the magnitude of the actual numbers seem small in this example, it must be remembered that this is a per customer estimate, and when multiplied by thousands if not hundreds of thousands of customers, the incorrect method of benefits estimation could overstate aggregate consumer benefits by millions of dollars.

Defenders of the savings method might concede its incorrectness, but counter that it is a simple and direct approach to getting some type of estimate of how the change in electricity consumption behavior will produce a benefit. A net consumer surplus calculation, they might argue, would simply be too complex. But the calculations outlined above are actually very straightforward, and require little or no additional information used to calculate net savings. All that must be known is the original flat price, the new time-of-use prices, and total usage within each pricing period (e.g., peak and off-peak) before and after the new pricing was introduced. A final objection might be that these equations assume, as the diagrams suggest, linear supply and demand curves, which do not reflect the actual response of supply and demand to pricing. But the same calculations could be performed using curves rather than lines, with just a little bit of higher mathematics involving the calculations of areas under curves. And the equations used above only assume that linear – or near linear – behavior is occurring in the region of the curves where the prices are changing. This is a simplifying assumption, but the estimate produced will still be far superior to one based on a savings calculation, which can produce results that are off by orders of magnitude, or – even worse – results that indicate a net consumer benefit where none has been realized (as in the coffee example). The errors in estimating consumer benefits that arise from the savings calculation are not due to simplifying assumptions, but due to the fact that the savings calculation is fundamentally wrong to begin with.

A Note on Producer Surplus

There is another stakeholder affected by a change in retail electricity pricing practices, and that is the producer. In a wholesale electricity market, a producer of electricity will sell power at an hourly market rate to the local distribution company, and will be compensated for sales at that rate. In essence, the producer does not know (and does not care) what price the retail electricity customer is paying, but deals exclusively with "real-time" market prices. The local distribution company, on the other hand, will pay for wholesale electricity prices on a "real-time" basis, but will charge prices to its end-use customers that are based on regulated rate designs. In the flat pricing scenario, these regulated rates may have no relation to actual "real-time" market prices, except that in the long-run, at least, the total amount paid by the local distribution company for electricity must equal the total amount collected from its customers.

From the producer's perspective, a change in the local distribution company's retail rates, from a flat-pricing rate design to a peak/off-peak pricing design, will result in a reduction in demand for electricity during the peak hours, and an increase in demand during the off-peak hours. The demand curve will appear to shift leftward during on-peak hours, resulting in a decrease in the price of wholesale electricity, and will appear to shift rightward during off-peak hours, resulting in a wholesale price increase. Hence, the producer will be selling less electricity, and for a lower price, during peak hours, and will be selling more electricity, and for a higher price, during the off-peak hours. Using the same calculation procedures outlined in the last section, it is easy to show that net producer surplus will decline during the on-peak hours and will increase during off-peak hours, and that the changes in each period can be calculated as follows:

On-Peak Change in Producer Surplus: (New Price – Old Price) x (New Hourly Consumption)
+ ½ (New Price – Old Price) x (Change in Consumption)

Off-Peak Change in Producer Surplus: (New Price – Old Price) x (Old Hourly Consumption)
+ ½ (New Price – Old Price) x (Change in Consumption)

(Note that in these and the consumer surplus formulas, the change in consumption is expressed as an absolute value, and therefore is a positive number, even if the change was a reduction in usage and sales.)

Using the data from the earlier numerical example with these formulas indicates that the total net change in producer surplus per customer per year is -$9.50: a loss which is nearly as large as the net gain in consumer surplus calculated above. The calculation highlights the fact that there are both winners and losers when a regulated utility switches from flat pricing to peak/off-peak rates, and the aggregate impact upon all parties might actually be close to zero. While consumers tend to benefit, producers of electricity may see significant losses associated with a decline in sales margin. This example serves to drive home the point that a business case must be oriented to a specific class of beneficiaries, in order to determine if it is economical for them to share in the costs of smart grid infrastructure investment. In the case of demand response, "casting a wide net" may actually weaken the business case, as it provides net benefits to one class of stakeholders but net losses to another. On the other hand, from an electric ratepayer's perspective only, demand response tends to be a positive thing, and the net consumer surplus calculation might contribute to providing a cost-justification for their investment in the infrastructure that would make it possible.

The AMI Case Revisited: Quantifying the Remaining Benefits

In light of the discussion in the preceding sections, it is now possible to assign values to deferred capacity and consumer surplus. Assuming that 20% (about 174,000) of all residential customers enroll for the peak-time pricing plan described above, and assuming that they have a coincident peak, then the reduction in total system peak demand will be 30 MW, and, at $85 kW-Yr, this translates into an annual capacity savings of $2.55 million. The total gain in consumer surplus, which was estimated above as $11.41/customer, will be $1.99 million/year. Hence, the aggregate benefit to consumers of providing a dynamic pricing option will $4.54 million/year, or $26.10 per year for each customer enrolled in the pricing plan. It must be remembered that there will be a net loss in producer surplus as well, which amounts to $1.65 million a year. This amount can be ignored in the ratepayer business case, but in the shareholder case it should be included. In that case, the negative producer surplus roughly corresponds to the lost margin that will result from the change in electricity sales patterns attributed to demand response.

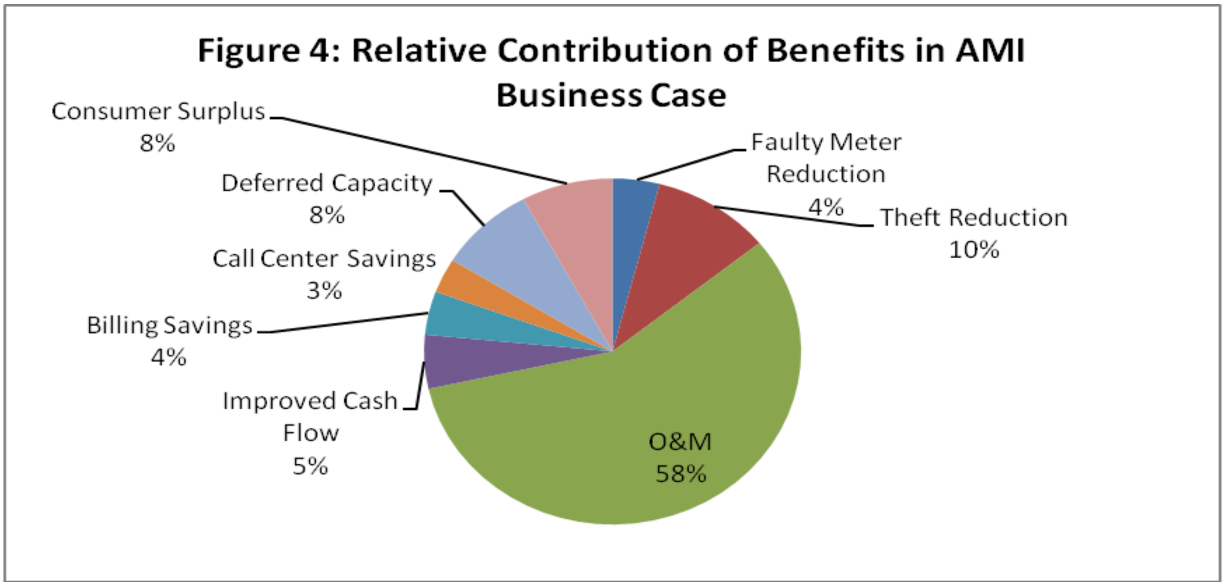


Figure 4 illustrates the typical relative annual contribution from each of the major benefit categories listed earlier in Table 4. While a full business case analysis would account for tax and depreciation effects, and the impact of incremental carrying charges on electricity rates, a high level estimate can be derived of the net benefits of AMI to the consumer, based on the cost and benefit assumptions derived above. Assuming a five-year rollout of the meters, a twenty-year life of each meter, a full pass-through of benefits and cost-savings to the consumer as they occur, and a consumer discount rate of 8%, the net present value of costs and benefits are as follows:

Table 5: AMI Net Present Value of Costs and Benefits @ 8%

Costs		Benefits	
Meters:	$ 60,100,000	Reduced Meter Reading O&M:	$123,070,000
Remote Disconnect Collars:	$101,820,000	Salvage:	$ 1,660,000
Meter Data Backhaul:	$ 3,990,000	Reduced Meter Error Losses:	$ 8,610,000
AMI System Integration:	$ 800,000	Reduction in Energy Theft:	$ 21,830,000
Incremental Operating Costs:	$ 10,160,000	Improved Cash Flow:	$ 10,810,000
Demand Side Management Software:	$ 930,000	Billing and Call Center Savings:	$ 8,730,000
Marketing for New DSM Rates:	$ 20,000	Deferred Generation Capacity:	$ 17,800,000
		Gain in Consumer Surplus:	$ 16,800,000
Total Costs:	$177,820,000	**Total Benefits:**	$216,270,000

Concluding Remarks

As the electricity industry embarks upon what may be the most expensive and sustained investment in infrastructure modernization in its history, it is imperative that the effort be guided by what might be called an enlightened pragmatism. The particular challenge underlying the effort is that while the end state is not entirely clear, every intermediate step taken toward that state must be justified by sound principles. This entails understanding – in the broadest possible manner – the benefits that will be realized by each particular investment, including those that might be contingent upon other investments, or that will not materialize until some remove into the future. But conversely, every benefit so identified must be capable of undergoing a rigorous justification. It must be linked to a specific beneficiary, it must be measurable, and it must be verifiable after the fact. One of the biggest threats to the success of this grid modernization effort is that projects are oversold early in the process, with projected benefits that do not materialize. Frequent occurrences of this will result in skepticism, particularly among regulators who may already be reluctant to approve capital investment projects that will raise rates to electricity consumers in a weak and faltering economy.

A rigorous business case is the best preventative against such a severe setback. Advocates for grid modernization must be, in a sense, their own greatest critics, and adhere to strict standards in business case development that will serve to minimize the risk of failed expectations and adverse outcomes. This paper has attempted to lay out, in a systematic fashion, the general principles for developing such a case while avoiding many of the pitfalls that could result in external criticism of the case when it is presented and/or negative outcomes after the underlying project is approved and carried out. It is hoped that the practical advice in this paper will provide useful assistance in developing a plausible business case, and thereby ultimately contribute to the ultimate success of the grid modernization effort itself.

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