# Incorporating Energy Efficiency into the Transmission & Distribution Planning Process – Potential Financial and Reliability Implications

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## ABSTRACT

This paper seeks to highlight issues that warrant further evaluation associated with more precisely incorporating energy efficiency (EE) into a utility's system wide transmission and distribution (T&D) plan from a financial and load forecasting perspective while accounting for system reliability and ratepayer concerns. This paper also analyzes how EE is integrated into grid operators' transmission and distribution planning process and whether or not EE can be an effective tool in either displacing or delaying the need for system upgrades. The research focuses on the financial and reliability implications of integrating EE, including EE subsidized distributed generation (DG), into system planning and the subsequent benefits to ratepayers as a result of better allocation of utility funds. This research topic fits in with the broader national effort to analyze how non-wire alternatives can be factored into a utility's T&D planning process.

## Current State of Energy Efficiency and Planning

Energy efficiency (EE) has been viewed by many as a least cost alternative for meeting growing electricity needs. As a result, the amount of money spent on EE programs has been rapidly expanding over the past two decades. This has given rise to reductions in energy use and an interest in to what extent increased EE has led to ancillary benefits such as the cost savings associated with the deferment or cancellation of transmission and distribution (T&D) projects. Load forecasting is the critical piece that links the growth of EE to its effect on T&D planning (see Figure 1). This paper seeks to highlight some of the obstacles associated with more precisely incorporating EE forecasts into both load forecasting and T&D planning, identify areas that would benefit from further evaluation, emphasize the role evaluation already plays in the process, and underscore the positive stakeholder impacts that are associated with closer integration.

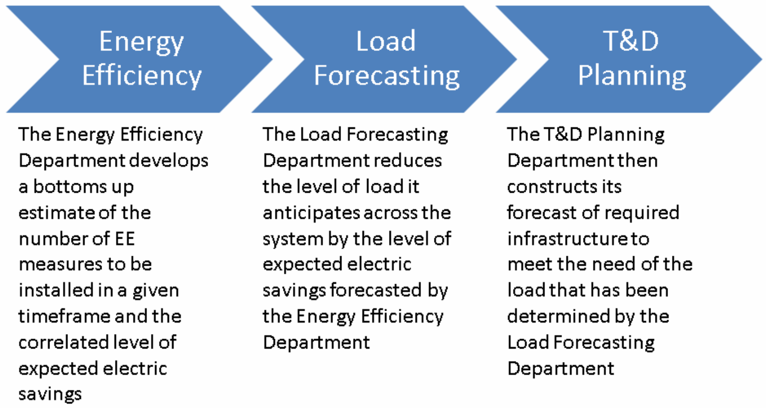



**Figure 1.** Interplay Between EE, Load Forecasting, and T&D Planning

Accounting for EE in T&D planning and load forecasting has become a significant issue due to the sheer size of EE programs across the nation. According to the 2012 American Council for an Energy-Efficient Economy (ACEEE) state energy efficiency scorecard, spending on electric EE has increased nearly six fold in the last 12 years, from $1 billion in 1999 to $5.9 billion in 2011 (Foster et al. 2012, 18). EE budgets range from 5.77% of utility revenues spent on EE in Massachusetts to 0% for Alaska, North Dakota, Virginia, and West Virginia (Foster et al. 2012, 26). Since load forecasting and T&D planning are location specific, the dollars spent in each region are an important indicator of the magnitude of effect that EE may have on the deferment of T&D projects and possible reallocation of funds to other reliability projects.

The large amount of dollars being spent on EE can be generally categorized into a few different types of programs, each of which can have very different effects on load forecasting and T&D planning. Passive EE programs result in the overall reduction of energy usage by replacing old equipment with more efficient equipment, essentially bringing the whole load shape down, peak and off-peak load. Active EE, such as demand response (DR), behaves nearly identical to any other supply resource and can "serve" load in real time under normal conditions or can be called on in an emergency event that requires immediate load reduction. DR can be targeted specifically to reduce peak load or to reduce load in a specific geographic area if loss of a transmission line or generator results in a system constraint. The last broad category of EE is distributed generation. Technology like combined heat and power (CHP) units may be a part of EE programs. At NSTAR, CHP units are considered to be passive resources. Before a CHP unit is incentivized, all other measures are implemented at a site, and then a CHP unit is sized appropriately to the thermal load at that site and installed. This potentially results in removing load off the grid, similar to a passive EE resource.

Across the country, utilities often have to report the success of the different types of EE programs listed above to their regulators as a percent of sales. Since sales are measured in kilowatt hours (kWh), regulators are appropriately more concerned about the reduction in levels of electricity consumption and not necessarily reduction in demand from the transmission system. This can lead to a dichotomy between the end goals of utility commissions and grid operators, and affects how evaluation studies are scoped. Grid operators are concerned about the level of demand, measured in kilowatts (kW), when they incorporate the effect of EE in their load forecast and transmission planning as this is how generation and transmission capacity is measured. It cannot be overstated that grid operators must plan their system to serve load during hours of the year when electricity usage is at its peak. Therefore, for T&D planning purposes, the demand reduction (in kW) of EE programs is essential to determine if T&D upgrades can be deferred. In order to meet the objectives of regulators and grid operators, utilities and EE program administrators should consider including research objectives that focus on kW and kWh. An example might be using lighting loggers from an hours-of-use study to also determine lighting peak coincidence factors.

In addition to reductions in electricity usage, state utility commissions also want to ensure that all customers have access to cost-effective EE programs, regardless of location or income status to maintain equity between ratepayers. Conversely, it may be more beneficial from a grid operator perspective to have EE measures targeted at a constrained geographic area, or target a specific end use that contributes to peak demand in order to alleviate overburdening the grid in a specific area. Ultimately, utilities must evaluate the overall costs and benefits to the ratepayers of each of the strategies and goals in designing programs effectively.

**Utility Integration of EE into Load Forecasting – NSTAR Electric**

As diagrammed in Figure 1, the critical juncture of how the various EE programs lead to modifications in T&D planning is the incorporation of EE into load forecasting, which subsequently allows T&D planners to make informed decisions about whether or not new T&D infrastructure or upgrades are needed and in what location(s). At NSTAR, the total estimated EE reductions are relayed to the load forecasting department, who in turn use that estimate to proportionally reduce the load across the service territory. EE data is collected at the zip code level, which could be mapped to individual substations, so it is theoretically possible to distribute the anticipated energy reductions to specific regions. However, this could result in misleading forecasts because past participation in EE programs is not an accurate geographic predictor of future participation.

When NSTAR submits EE data to the regional Independent System Operator (ISO) for the ISO's load forecast, it is first subjected to rigorous Evaluation, measurement, and verification (EM&V) procedures in order to ensure the accuracy of the data. An example of a key role that EM&V plays in ensuring the accuracy of EE forecasts is the development of a realization rate that can be applied to estimated EE savings numbers. A realization rate is a discount factor applied to name plate savings to account for issues like shorter running time than expected or operating conditions that result in higher or lower than anticipated savings. Additionally, EE savings are sometimes reported as "net" that includes other factors such as free-ridership which discount savings that actually occurred but were not attributable to utilities. EM&V helps back out the effect of free-ridership which is important because forecasts should include all actual reductions that occur, regardless of attribution of savings.

**Grid Operator Integration of EE into Load Forecasting – ISO-NE and NYISO**

ISOs conduct load forecasts in order to evaluate future system needs and ensure the reliable operation of the grid from a regional, rather than utility-specific, perspective. ISOs must examine the interplay of generation and transmission resources across multiple load zones and multiple states. ISOs may use different methodologies to incorporate EE into load forecasts from each other and from utilities.  These differing assumptions can have a profound effect. For example, ISO New England (ISO-NE) develops its 10 year EE Forecast by treating EE as a supply resource like generation and bases the first three years of its forecast on the level of state sponsored/funded EE bid into the Forward Capacity Market (FCM). Previously, the amount of load assumed to be reduced by EE in years 4-10 was held constant in the ISO-NE forecast. Now, ISO-NE develops a long term EE forecast for years 4 through 10 using incremental efficiency gains beyond the FCM time horizon (See Figure 2).  Figure 3 shows the effect of ISO-NE's different planning assumptions on peak energy usage. The blue line is a business as usual forecast. The red line includes the EE reductions known from the FCM and then held constant after the first three years. The black line shows the net load after the EE reductions known from the FCM and the EE forecasted in years 4-10 are subtracted from the gross load, or business as usual forecast (Rourke 2013).

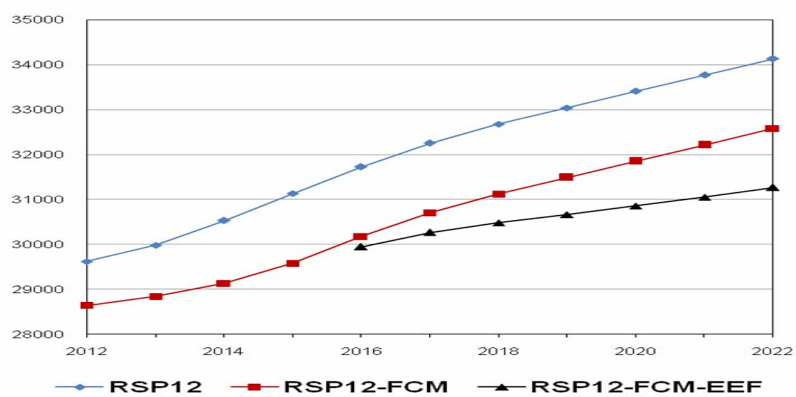



**Figure 2. New England: Summer 90/10 Peak (MW)**

In order to forecast how much peak load will be reduced by EE in years 4-10, ISO-NE develops its forecast by using budget projections, production costs, inflation, a budget uncertainty factor, and peak to energy ratios. The budgetary uncertainty factor allows ISO-NE to account for the fact that EE program administrators (PAs) do not always spend their entire budget. The production cost escalation factor accounts for changes in measure mix going forward, and that those future measures may be more expensive than current ones. Overall budgets are assumed to be constant, using the last public utility commission approved budget in each state as the baseline. Peak to energy ratios are based on historical averages but these are variable and a small change can have large reverberations on load forecasts. The equations that ISO-NE uses to estimate the MW savings attributable to EE in the out years are shown below in Table 1 (ISO New England Staff 2013).

**Table 1.** ISO-NE Forecast Calculations

| **MWh= [(1-BU)*Budget $]/[$/MWh*PCINCR]**<br>**MW = MWh*PER** | |
|---|---|
| Budget $ = | estimated EE budget dollars |
| BU = | budget uncertainty |
| $/MWh = | production cost |
| PCINCR = | production cost increases |
| PER = | peak to energy ratio |

In New York, forecasting and planning are done a bit differently than in New England. The New York ISO (NYISO) does not allow EE to be bid into its capacity market so it cannot use the level of EE bid into the FCM as a starting point for a long term EE forecast. Instead, NYSIO has been involved in the development and execution of the New York State Public Service Commission Energy Efficiency Portfolio Standard (EEPS), which helps guide its assumptions on the level of EE that will be installed. Specifically, the NYISO 2012 Reliability Needs Assessment lays out the following inputs that guide its forecast (New York Independent System Operator 2012, 17):

- NYSPSC-approved spending levels for the programs under its jurisdiction, including the Systems Benefit Charge and utility-specific programs
- Expectation of the fulfillment of the investor-owned EEPS program goals by 2018, and continued spending for NYSERDA programs through 2022
- Expected realization rates, participation rates and timing of planned EE programs
- Degree to which EE is already included in the NYISO's econometric energy forecast
- Impacts of new appliance efficiency standards, and building codes and standards
- Specific EE plans proposed by LIPA, NYPA and Consolidated Edison Company of New York, Inc. (Con Edison)
- The actual rates of implementation of EEPS, based on data received from Department of Public Service staff., which leads to a discount of future planned EE

While the starting point for the forecasts is slightly different, the main variables are similar. Both forecasts rely upon a combination of budgetary assumptions, program participation rates, and future cost increases. The important issue to note is that all of these assumptions have a direct impact on the final EE forecast. Further complicating this analysis is that the numerical values used by the ISOs are not always unanimously agreed upon.

## Risks and Challenges Associated with EE Integration

### Small Assumptions, Big Difference

Even with ISOs and utilities using advanced forecasting techniques, changing small assumptions can have large overall effects on a load forecast. This impact highlights the difficulties involved with more precisely incorporating EE into load forecasts. In 2010, the Midwest ISO hired Global Energy Partners (GEP) to conduct a 20 year load forecast incorporating EE and DR. One of GEP's main assumptions was that average annual EE savings as a percent of baseline decreased over the course of the forecast because GEP assumed a saturation point of EE measures (GEP 2010). In a response to the forecast, Synapse Energy Economics ran several scenarios using most of the same assumptions as GEP in the forecast except that they changed the average annual EE savings (Peterson, Sabodash & Takahashi 2010, 11). Table 2 highlights how changing that assumption in a load forecast can result in thousands and even tens of thousands of megawatts difference in peak demand savings. The difference in the anticipated MW savings could potentially be the deciding factor between constructing and not constructing new transmission lines.

**Table 2.** Peak Demand Savings Sensitivity in Midwest ISO Forecast

| Scenario | Description | Peak Demand Svgs |
|---|---|---|
| GEP Scenario | Declining avg EE savings from 1% in 2015, 0.9% in 2020, 0.3% in 2025, 0.1% in 2030 | 11,233 MW |
| GEP with Fixed Savings Scenario | 1% savings throughout forecast period | 19,373 MW |
| Synapse State's Avg | Avg EE savings increases from 1% through 2015 to 1.4% from 2015-2030 | 23,392 MW |
| Synapse Best Practices | Avg EE savings jumps to 2% from 2020-2030 | 29,618 MW |

Another important aspect of the GEP study was that some of the data for the forecast was aggregated using ratios that are subject to change. GEP tried to collect data directly from the companies that operate within the Midwest ISO and were very successful in their efforts but were not able to collect data from every single participant. Therefore, GEP had to make some assumptions about missing data by using known ratios such as program budget/energy savings, program budget/# of participants, energy savings/# of participants, and energy savings/demand savings (GEP 2010 2-12). The issue with these assumptions is that these ratios can change going forward. For example, a change in measure mix or the pursuit of harder to reach measures may cause the cost to acquire savings to increase. Furthermore, the ratio between energy savings and demand savings may also fluctuate. The dollar value of program budgets may also rise and fall with political administrations. This is not a comment on GEP's methodology, only that it is important to note all the intricacies and moving parts that go into a load forecast.

There are several additional differences between EE planning and T&D planning besides the example of average annual EE savings presented above that cause difficulties in incorporating the EE forecast into the T&D forecast. From a transmission planning perspective, there is a timing mismatch between the transmission and EE planning horizons. Often times, EE plans extend only a few years into the future while transmission needs are usually evaluated decades into the future. This requires planners to make long term assumptions for the years further out in their forecast, which can be very challenging. Also, transmission lines may be built for other reasons than strictly as a main conduit for electricity. Transmission lines may be built to provide reliability, market efficiencies, or to serve public policy goals such as accessing renewables. Load forecasts that incorporate EE likely wouldn't have a bearing on the decision making for the construction of new transmission lines for all the above scenarios. Moreover, for substation planning, EE may not be able to offset enough load growth in rapidly developing districts, which will affect the planning efforts in areas like the South Boston waterfront that are undergoing large growth. Also, further down into the distribution system there are fewer alternatives to spread the load over so EE would have to relieve overload on specific components. This isn't always feasible as most passive EE may not be targeted to a specific area. The reasons stated here are a few examples of why integration of EE with T&D system planning can be challenging.

### Contingency Planning

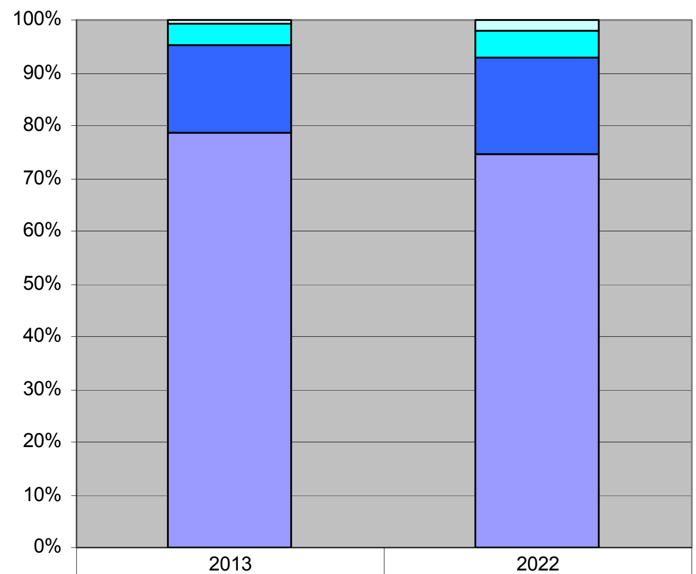
While conducting transmission planning studies, ISOs must study a range of possible contingencies to ensure reliable operation of the grid in case a major piece of equipment becomes unavailable. ISO-NE recently conducted a demand side Market Resource Alternative Analysis for the Greater Hartford and Central Connecticut area in order to determine how much demand reduction would be necessary to satisfy an N-1 event (loss of any one single system element) and N-1-1 (loss of a second system element 15 minutes after loss of a first element) contingencies. To conduct this analysis, ISO-NE factored in 100% of the passive EE and 75% of the active demand response that had cleared in all of the forward capacity auctions up until the time of the analysis. Furthermore, all additional EE forecasted to be installed through the end of the 10 year forecast period was included to arrive at net load (total load – active demand response – passive EE) at each load serving bus in the region. Next, an algorithm was run to determine the minimum amount and location for load reduction at each load-serving bus to relieve overloads in each N-1 and N-1-1 scenario identified in a previously developed transmission assessment. The result of the analysis is that a total reduction of 47%, or 1350 MW, would be necessary to satisfy all contingencies. It should be noted that the 47% reduction is for the whole area, and in some scenarios individual buses would require a 100% reduction (Perben 2013, 9). In typical N-1-1 scenarios, EE alone may not sufficiently offset the required reduction and thus eliminate the need for new transmission lines or generators.

In this same vein, grid operators usually design the electrical system based on extreme weather events. Often times the peak load occurs on the hottest day of the year when there is a huge draw on the grid due to high air conditioner (AC) use. If weather becomes more extreme, possibly raising temperatures and causing more ACs to be run at higher levels, equipment like energy efficient ACs may not be able to offset load growth to the point where new generation or transmission capacity is unnecessary. Evaluation studies may be useful in identifying measures, such as cooling and insulation, which can help alleviate strain on the grid during these extreme weather days.

## Benefits Associated with EE Integration

### Deferred Transmission and Generation Benefits

Despite the issues associated with incorporating EE into load forecasting and T&D planning discussed above, there are many benefits to doing so. These benefits accrue to various stakeholders and come in the form of both increased reliability and possibly lower costs. The North American Electric Reliability Corporation's (NERC) 2012 Long-Term Reliability Assessment cites that demand side management, including EE, is expected to total almost 80,000 MW by 2022 which equates to roughly 7% of on-peak resources. This would offset nearly six years of peak demand growth. EE programs alone account for nearly 19,000 MW in summer peak reduction over the 10 year forecast horizon (NERC Staff 2012, 41-42). NERC estimates that this has allowed companies to defer two years worth of generation capacity. While not quantified in the study, the deferment of two years worth of generation capacity would result in substantial cost avoidance for utility ratepayers. Figure 3 shows how EE is projected to become an increasingly more significant part of resource needs throughout NERC's long term forecast (NERC Staff 2012, 44).




| | 2013 | 2022 |
|---|---|---|
| EE | 0.6% | 2.2% |
| DR | 4.1% | 4.8% |
| Renew ables | 16.6% | 18.3% |
| Traditional Generation | 78.6% | 74.6% |

**Figure 3.** NERC Breakdown of Resource Needs Over 10 Year Forecast

One result of increased installation of EE measures is the deferral of transmission projects as load growth diminishes. In the NERC long term assessment, there is an observation that 230 transmission projects totaling nearly 5,000 circuit miles are considered delayed or deferred. The largest cause of transmission project deferrals is due to reassessment of load growth (NERC Staff 2012, 39-40). There are many reasons why load growth forecasts might change such as economic or demographic variables but EE is at least partly responsible for projections of diminished load growth. Like the avoidance of generation, there is substantial cost savings associated with transmission deferrals.

As transmission projects are delayed or deferred the money that would have been allocated to these projects are either not spent at all or are allocated to other projects that could enhance system reliability. In either scenario, there is a financial and/or reliability benefit to stakeholders. ISO-NE noted in its 2012 EE Forecast, 10 transmission upgrade projects in Vermont and New Hampshire that could be deferred until after 2020, resulting in a savings of $260 million (Rourke 2013, 17). Another way that EE could save ratepayers' money is that in some cases the aggregate level of EE may also be able to provide a temporary bridge between currently available transmission infrastructure and future construction. An example is in ISO-NE's Northeastern Massachusetts (NEMA) load zone where it was explored whether EE could provide a one-year temporary bridge to meet capacity needs until planned transmission was slated to come on line to relieve the load zone of capacity constraints. An alternative one year stop gap measure such as procuring expensive generation sources would come at a large cost to rate payers.

From a transmission-only perspective, EE arguably may not defer enough transmission costs to make sense but this does not consider all the benefits of EE. In the ISO-NE EE forecast, New England states are anticipated to spend $5.6 billion on EE programs from 2016-2022 (Rourke 2013, 11) and so far only the $260 million in deferred transmission investments discussed above have been identified. Using standard transmission planning assumptions, a 17% carrying cost and a 40 year investment recovery timeframe, results in a roughly $44 million per year charge and a $1.8 billion total price tag to pay for $260 million in construction costs, not accounting for time value of money. Comparing $1.8 billion vs. $5.7 billion to avoid the 10 transmission projects mentioned above makes it seem as though EE is not a good investment. But that misses many of the other benefits associated with EE. In Massachusetts alone, benefits associated with the electric portion of the 2013-2015 Three Year Energy Efficiency plan are expected to total over $7.5 billion with a cost of just under $1.5 billion (Massachusetts PAs 2012, 14). This is because in addition to deferred transmission benefits, there are avoided electricity and gas costs associated with EE. People who participate in EE programs also enjoy non-energy benefits such as increased thermal comfort, higher property values, and health benefits to name a few. These additional benefits are quantified as a result of evaluation studies under taken by the Massachusetts program administrators. It is important to consider all benefits associated with EE when judging the cost effectiveness of investments, especially when applying a Total Resource Cost test.

### Deferred Substation Projects

In addition to cost savings from avoided transmission projects, EE may also be able to generate cost savings from deferred investment in substation modification and/or construction. Substation deferments due to EE would likely only be feasible in specific situations such as in areas where there is limited load growth. If EE measures could reduce hypothetical load growth from 2% to 1%, it may be possible for that small load increase to be spread out over existing substations instead of building new ones. This could have a large financial impact in urban areas that have expensive real estate and where substations may have to be built underground or in enclosed areas, which can dramatically add to cost. Additionally, permitting and siting can be very difficult in urban areas. Again, any savings from deferred projects may be re-allocated to other projects that can increase system reliability.

## Opportunities to Improve EE Effect on T&D Planning

### Distributed Generation

Although EE is currently being integrated into load and T&D planning, with very real financial and reliability benefits, there is always the opportunity to improve. One idea that warrants further research and evaluation is whether there is a benefit to promoting the number of CHP units incentivized through EE. Traditionally, T&D planners have been reluctant to include the load reduction associated with CHP units in the forecasts because if a CHP unit goes off line, then the load it was serving will appear on the grid and it will need to be served from the existing infrastructure. Planners are especially concerned about the availability of CHP units, their forced outage rate, mean time to repair, and sensitivity to system power fluctuations. Essentially any issue that could take a unit offline is a concern to planners. But one area for assessment might be to better understand the costs and benefits associated with the installation of multiple smaller CHP units instead of one large unit, i.e. five 2 MW units instead of one 10 MW unit. In this scenario, a planner could potentially assume that even if a few units went down at any given time, the facility would not need to be supplied completely from the grid. This could lead to a situation where less T&D infrastructure would subsequently be required at that facility, resulting in a cost savings. An additional benefit would be that planners could target specific geographic areas that face capacity constraints.

CHP benchmarking data prepared for the DOE could possibly support the assertion that installing multiple smaller units may result in higher reliability. Table 3 below shows that for reciprocating engines and gas turbines, smaller units tend to have higher availability averages and lower mean down time in hours (Energy and Environmental 2004, 4-2). This is an area that requires more research as there is anecdotal industry evidence to suggest these findings are counterintuitive and the sample size in this study was small. Besides CHP unit reliability, the effect of a tripped interconnection would also have to be evaluated before planners could definitively exclude load from sites with CHP units from their forecasts. If CHP load could be excluded from load forecasts, then it would be beneficial to align incentive schemes in such a way that the building of multiple smaller units over one large unit would be encouraged. Any redesign of incentive schemes to promote multiple CHP units instead of one large unit would require a detailed cost analysis to demonstrate net positive economic benefits to the facility owner as well as the ratepayers.

**Table 3.** Availability and Down Times for Different Sized CHP Units

| Technology Group | Availability (%) Avg. | Mean Down Times (hrs) |
|---|---|---|
| Reciprocating Engines <100 kW | 97.93 | 13.71 |
| Reciprocating Engines 100-800 kW | 95.99 | 50.66 |
| Reciprocating Engines 800 kW - 3 MW | 98.22 | 27.06 |
| Gas Turbines 500 kW - 3 MW | 97.13 | 65.38 |
| Gas Turbines 3 MW - 20 MW | 94.97 | 68.63 |
| Gas Turbines 20-100 MW | 93.53 | 75.3 |

Another area where there might be an opportunity to better align EE into load forecasts, especially in capacity constrained areas, is to evaluate and survey what kind of distributed resources, such as CHP, rooftop solar, and home wind turbines exist behind customers' meters in a utilities' service territory. It is essential for planners to know what level of electricity may be drawn from the grid at any given time and as the number of distributed resources increases, this issue becomes especially important. As mentioned above, knowing the reliability and operating characteristics of a DG resource is critical for planners when they make assumptions of how much T&D infrastructure is needed for an area. With a low level of visibility or telemetry on behind the meter generating resources, it is likely that planners will assume that most of the DG resources are unavailable. Going forward, getting a clearer understanding of exactly what is behind the meter and how it operates will lead to better load forecast and planning assumptions. This should help avoid overbuilding T&D infrastructure and promote the optimal use of ratepayer funds.

Similar to distributed generation, utilities may also be able to target constrained geographic areas by piggybacking on existing behavioral programs. One widespread behavioral program involves sending out mailers with comparisons of household energy use, encouraging residents to lower their energy use as compared to their neighbors. These mailers could include rebate offers for new equipment. By offering rebates for efficient equipment, such as higher efficiency air conditioners, it would be possible to target equipment that substantially contributes to peak energy demand. One behavior program implementer claims that participation rates in programs can increase by up to 75% when promoted in their mailers or web portal (Opower 2012, 8). Because the reports are sent by mail it would be possible to target specific areas. It would then be the responsibility of evaluators to determine whether or not geo-targeting a specific area is having the desired effect.

**Non-Wire Alternatives**

Some utilities and ISOs have gone even further in their analysis of how EE could be better incorporated into the T&D planning process by establishing non-transmission alternative committees. An example of this is the Bonneville Power Administration's (BPA) Non-Wires Solution Initiative. BPA has institutionalized this analysis by employing screening criteria for all capital transmission projects over $2 million to see if a non-wires solution is a feasible alternative to new construction (BPA 2004, 4). Passive EE is not the only alternative considered, as demand response, distributed generation, generation siting, and pricing strategies are also possibilities as non-transmission alternatives.

BPA employs an inclusive process to ensure that viewpoints from across the company and external stakeholders are heard when considering how to integrate non-wire alternatives into its construction planning process. Table 4 highlights the different internal departments, including EE Planning and Evaluation, represented at BPA's Non-Wires Solutions Round Table. This reflects how important it is to have a comprehensive view of the transmission construction process and where there might be opportunities for alternative solutions (Non-Wires Solutions Round Table 2012). It is important to get key decision makers together when considering how best to integrate EE into load and T&D planning as different stakeholders may have competing motives.

**Table 4.** Internal Stakeholders Attending BPA Non-Wires Solutions Round Table

| | | |
|---|---|---|
| Long Term Planning | Operations | EE Planning and Evaluation |
| Public Affairs | Project Managers | Transmission Planning |
| Power Services | Regional Relations | Transmission Services |
| Network Planning | Government Affairs | Environmental |

The BPA planning example may serve as a useful template of how other utilities could bring key players together and institutionalize the process of considering how EE may be able to displace the need for new construction.

## Final Thoughts

EM&V plays a critical role in integrating energy efficiency into load forecasts. EM&V is the mechanism that allows forecasters to have the most accurate numbers available. It would be infeasible to place meters at the installation site of every piece of energy efficiency equipment so it is necessary to base overall energy reduction assumptions on statistical analysis. A rigorous EM&V program ensures that the data collected from the field meets the high level of precision at the required confidence levels to satisfy the expectations of ISOs and be included in future load and transmission forecasts.

As EE measures become more widely deployed, it is important that utilities and grid operators understand the ancillary benefits associated with lower energy consumption. This can be accomplished through better integrating EE into load forecasts and subsequently T&D planning assumptions. Going forward, surveying and evaluating the operating characteristics of distributed resources and where they are located will help eliminate blind spots in resource and system needs and allow better planning assumptions. The ultimate goal is to allocate funds in such a way that maximizes reliability and cost savings for customers.

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