American Council for an Energy-Efficient Economy
WASHINGTON, DC

Comments of the
American Council for an Energy Efficient Economy (ACEEE)
on the Federal Energy Regulatory Commission's
Proposed Rule on Standard Market Design
January 10, 2003

ACEEE is pleased to submit these comments on the Commission's proposed Standard Market Design rule. ACEEE is a nationally-recognized energy policy research and advocacy organization with more than twenty years experience in the energy efficiency field. In the electricity sector, we have been active in developing policy and program recommendations for Congress, federal agencies, state legislatures, state utility commissions, utilities, and public benefits administrators.

Following a summary section, our comments are presented in two primary categories: general comments and comments specific to sections of the NOPR.

Summary

While the proposed rule reflects the Commission's appreciation of the need for increased demand-side resource participation in electricity markets, it falls short on key specifics that are essential to ensure that the full scope of demand-side resources is included in the emerging electricity markets the Commission envisions. Energy efficiency represents at least half of the demand response potential in the U.S. electricity system, but the proposed rule does not go far enough in enabling energy efficiency to participate in key market processes.

Energy Efficiency Improves Reliability. Efficiency and other demand-side resources reduce strain on the entire electricity system, at a cost that is very competitive with generation and transmission resources. Efficiency has delivered about half of the 30,000 MW of peak capacity avoided by demand-side programs to date, and ACEEE research projects that targeted efficiency programs can achieve another 64,000 MW in peak reductions over the next decade, avoiding about half of forecast peak load growth.

Efficiency Is a Viable Form of Demand Response. Most of what is construed as Demand Response in the proposed rule is really load management, which typically consists of very short term shifts or curtailments of load during peak conditions. Load management may not save any energy on net, whereas energy efficiency can achieve the same peak reductions, but also delivers other benefits load management does not provide, such as air pollution emission reductions and ongoing customer bill reductions.

Energy Efficiency Mitigates Market Power and Moderates Prices. Experience in several markets has shown that efficiency programs have measurable effects on reducing the effects of generator market power, and on reducing wholesale market prices, to the benefit of all customers on the system. Data from New England show that the value of efficiency programs to the wholesale market ranged as high as $114 per Megawatt-hour. Since efficiency programs have been widely documented to produce savings at a cost of less than three cents per kilowatt-hour, these programs are very cost effective.

Energy Efficiency Provides Environmental Benefits. Unlike most load management programs, which simply displace energy use and accompanying pollutant emissions from powerplants, energy efficiency provides ongoing pollution avoidance benefits to the entire electricity system. This fact must be recognized in the planning and management processes the Commission designs for power markets.

Energy Efficiency Reduces Customer Bills. In addition to moderating peak wholesale prices, benefiting the entire system, efficiency offers individual customers both lower bills and a hedge against price volatility. Since it is likely that prices in unregulated power markets will always be subject to volatility, it is important to give customers the risk-management value that efficiency provides.

Energy Efficiency Has Been an Important Element of Electricity System Planning. Over the last twenty years states have used efficiency as an important resource-planning tool to moderate demand forecasts and to acquire demand-side resources as a lower-cost alternative to conventional generation, transmission, and distribution investments. Efficiency programs helped cut electric demand growth rates in half during the 1990s, while economic growth soared. Efficiency spending rose as high at $1.6 billion in the early 1990s, but has been cut almost in half by the effects of restructuring.

Energy Efficiency Must Be Re-Integrated Into System Planning. State utility commissions, whose resource planning processes drove the demand-side investments of the 1980s and 1990s, have now been stripped of most of their resource planning purview, and are mainly limited to distribution utility regulation. The Commission's proposed rule recognizes the need for a new resource planning framework to fill in the gaps left by restructuring. However, the Commission will have failed its public service obligation if it does not adequately engage energy efficiency as a meaningful part of electricity market planning and operations. Efficiency represents at least half the demand-response potential, produces superior benefits in terms of reliability, pollution prevention, and customer savings, and thus must be part of the new regionalized framework for electricity system management.

Specific Recommendations:

- **Transmission Pricing.** The Commission should make explicit that demand-side programs and related costs, as well as transmission hardware and facilities, may be recovered via pricing mechanisms. ITPs and RSACS should explicitly be enabled to recover costs for energy efficiency and other distributed resources, in tariffs, uplift charges, or through public benefit charges.

- **Day-Ahead and Real-Time Market Services.** We support the combined day-ahead and real-time market design approach. It has been shown to create opportunities for load response in exemplary markets such as PJM. However, important issues must be detailed and addressed if the full potential of demand response is to be tapped in these markets. Metering issues are key, in that most smaller customers do not have and will not have access to interval metering for some time. However, many utilities already use not-metering methods to bid capacity into ISO markets. These technologies are readily available and cost-effective. Demand-response markets must be set up such that LSEs and third parties are enabled to bid into ITP markets without requiring revenue-grade interval metering. The Commission should require states, ITPs, and other parties to work out methods for enabling these approaches.

- **Regional Planning Process.** The principles stated by the Commission in the proposed rule place the ITP in the role of resource portfolio manager for its regional electricity system. We believe this role is an appropriate one, and we address these specifics in our comments on the Long-Term Resource Adequacy provisions of the proposed rule. We also recommend that the rule state explicitly that regional transmission planning and resource adequacy planning processes should be coordinated at the ITP and RSAC level to take advantage of potential synergies.

- **Long Term Resource Adequacy. (LTRA)** We support the intent and general design of the LTRA requirements. We also recommend additional specifics as follows:

  - **Resource adequacy requirements should define minimum levels of demand response.** These should be set based on regional analyses of minimum levels need to prevent market power abuse.

  - **ITPs and RSACs should conduct regional resource analyses.** These resource analyses should include conventional central station generation, distributed generation, combined heat and power systems, energy efficiency, load management, and interruptible loads.

  - **Resource plans should meet minimum requirements**:

    - Plans must include specific resource technical and economic potential analyses for a range of supply-side and demand-side resources, including conventional central station generation, distributed generation, combined heat and power systems, energy efficiency, load management, and interruptible loads.
    - Plans should be required to address a minimum time frame, suggested at 10 years.

    - Baseline forecasts must specifically take into account energy efficiency policies and programs in place or expected to be implemented during the planning period.
    - Plans must demonstrate that they have identified and procured a low-cost, and low-risk, mix of resources that can reliably meet forecast customer demand.

- **State Participation in RTO Operations.** Structure and governance of the RSACs and ITPs, and the processes under which they operate, are crucial to the effectiveness of the proposed rule. While Governors are likely to decide on appointments, the Commission should encourage consultation with state legislatures, utility commissions, people's counsels, and state energy and environmental agencies. RSACs should appoint subcommittees for the issues listed in paragraph 554 of the proposed rule. Each state's oversight council should appoint representatives to these committees, should oversee their activities, and should receive annual reports from them.

- **Governance for Independent Transmission Providers.** We agree with the Commission's recommendation for six defined stakeholder classes, and for advisory committees reflecting these classes. However, we would also reinforce the Commission's proposed principle that no one company, or any of its affiliates, may participate in more than one committee in any one year. We recommend that the Commission establish an appeals process for ITP governance issues. If stakeholders participating in the advisory process believe that the intent of this rule is not being upheld, they should have access to a well-defined and timely process for bringing these matters first to the ITP Board, and then to the Commission if they choose to appeal the ITP Board's decision.

    - We also urge the Commission to establish a financial support mechanism for stakeholders who do not receive direct and significant financial benefits from the operations of the regional electricity system. These would include public interest representatives, alternative energy providers, and customer representatives.

General Comments

The Commission's proposed rule provides a welcome forum for discussion of the role of energy efficiency in future electricity markets. The proposed rule holds the potential for using energy efficiency effectively as a vital tool for improving system reliability, reducing market prices, mitigating market power, reducing air pollution emissions, and reducing customer bills. However, the current NOPR falls short of the specific provisions that would be needed to ensure that energy efficiency is given full and fair consideration in the management and planning of the nation's electricity markets. We have outlined in these comments specific improvements to the proposed rule that we believe are necessary to achieve essential provisions for energy efficiency in the operations of the regional electricity markets envisioned in this rule.

Energy Efficiency Improves Reliability. If we visualize the electricity grid as a linked chain of generation, transmission, distribution, switching, transformer, and other facilities, we can visualize end-use demand or "load" as the weight on the end of the chain. More sophisticated observers might see the grid as a network, looking more like the "chain mail" used in medieval armor; in this view one can see multiple load centers pulling down on the network. Either way, lessening the load reduces strain on all parts of the chain or network, and thus reduces the risk of outages or other failures in the grid.

The more common approach to reliability is to focus on strengthening weak links in the chain: upgrading transmission facilities, updating relays, switches, and transformers, or adding generation. While this approach is important in that weak links increase reliability risks, it tends to focus on one link at a time, since the measures needed to improve each link are different. A load modification approach benefits all the links in the system, and also provides the flexibility to address load pockets and other high-risk areas in the grid. The conventional reliability improvement approach has tended to take load, and load forecasts, as givens, when history shows that market forces, policy and program interventions, or both can significantly reduce load forecasts.

Energy efficiency programs documented by the U.S. Department of Energy have reduced peak demand nationally by about 15,000 MW in recent years.[1] Demand-side management programs overall reduced U.S. peak demand by about 30,000 MW, or about 4%. Roughly half of this reduction came from load management programs, and half from energy efficiency.

The distinction between load management programs, which are typically aimed at reducing load only during short, specified time periods, and energy efficiency, which tends to reduce load across a broader spectrum of the load curve, is important for the purposes of this rule. For example, a direct load control program that places remotely controlled switches on home air conditioners would be an example of load management. It would shut off the unit's compressor for specific intervals during peak-day conditions. An efficiency program that installed a right-sized, more-efficient unit with leak-free air ducts can produce comparable peak load reductions, but it also produces more overall benefits in terms of energy, customer bills, and air pollutant emission reductions.

As currently drafted, the proposed rule appears to define load-reduction options almost entirely as short-term load management efforts. This key imbalance threatens to leave at least half the nation's load reduction potential unavailable for participation in electricity markets. We believe that would be bad public policy. ACEEE research shows that substantial peak reduction potential remains to be harvested through energy efficiency. By targeting end uses whose peak demand is highly coincident with typical system peaks, such as building air conditioning and commercial lighting, U.S. peak load growth can be reduced by 64,000 MW in the next decade, which is about half of the load growth forecast by the Department of Energy's Energy Information Administration. However, for this potential to be realized, barriers to efficiency must be reduced. The Commission should thus seek to reduce barriers to energy efficiency in its Standard Market Design.

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[1] http://www.eia.doe.gov/cneaf/electricity/dsm00/dsm_sum.html

Energy Efficiency Mitigates Market Power and Moderates Prices. In regulated electricity markets, the economic value of a kilowatt-hour saved was limited to the avoided cost of a marginal unit of generation. But in the markets taking shape under the purview of this rulemaking, saved energy reduces the market-clearing price for all customers in the affected wholesale market. This creates enormous new leverage for the value of saved energy. In Massachusetts, for example, the Department of Energy Resources calculated that direct benefits to participants in the state's energy efficiency programs totaled about $20 million in 1999. However, during just one peak day that year, these programs created over $6 million in benefits to all NE-ISO customers in the form of reduced energy clearing prices. In the PJM market, the value of load reductions averaged almost $68/MWh, and ranged up to $114/MWh.[2]

In California, energy efficiency and load management helped resolve the largest electricity market crisis in years. During 2001, efficiency and load response programs helped reduce total electricity usage in the state by 6%, and peak demand by up to 12%. In the words of the state's highest energy official, "Energy efficiency took the wind out of the California wholesale market."[3] This dramatic demonstration bore out earlier findings that efficiency programs produced benefits for the entire customer base several times greater than those enjoyed by direct participants in efficiency programs.[4]

The experience to date in wholesale markets indicates that generators, left without adequate demand-side competition, tend to behave in ways that drive up the market clearing price. Market design and rules can help mitigate these kinds of behavior, but the best solution in an ostensibly free market is to enable sufficient levels and diversity of competition such that competitive behavior brings market prices down to reasonable levels. The experience in California and New England, where vigorous efficiency programs have been implemented, shows that efficiency can deliver significant price benefits through moderating wholesale prices.

The Federal Trade Commission's 2001 report on electricity industry restructuring contains a chapter on demand-side resources, aptly subtitled "The Sound of One Hand Clapping." The FTC's analysis asserts that a vigorous demand-side market is not only desirable but essential for electricity markets to succeed. It debunks the idea that mitigating market power can be achieved through addressing the generation side of the market alone. Even if sufficient numbers of generators could be brought into the market initially, the trend toward consolidation in unregulated power markets runs the perpetual risk of re-concentration. It is thus essential that demand-side competition from energy

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[2] Rich Ferguson, "The Public Value of Load Reduction in the California Market". CEERT, 1999.
[3] David Freeman, Chairman, California Power Authority. From remarks given at the Alliance to Save Energy Policy Forum, Washington, DC, October 2001.
[4] Ferguson, Op. cit., and Marcus and Ruszovan, "Cost Curve Analysis of the California Power Markets", testimony in App. 99-03-014, California Public Utilities Commission, September 2000.

efficiency and other distributed resources be made viable and vigorous if the Commission's goals for the proposed rule are to be met.

Energy Efficiency Provides Environmental Benefits. Efficiency prevents air pollution emissions, making it a cleaner as well as a more economic resource than conventional power generation. Under the National Environmental Policy Act (NEPA), the Commission like all federal agencies is obliged to consider the environmental impacts of all major federal actions. While the current rule may not require a formal Environmental Impact Statement, we believe the Commission wishes to follow the spirit of NEPA, and in this regard should give full consideration to the environmental benefits of energy efficiency.

Other agencies, including the Environmental Protection Agency (EPA) and the Ozone Transport Commission (OTC) have made significant progress in applying energy efficiency resources in specific emissions reduction regimes. In the late 1990s, EPA conducted pilot programs in New York and New Jersey to test the ability of energy efficiency programs to deliver emission reductions under its Nitrogen Oxides State Implementation Plan (NOx-SIP) regime. This experience encouraged the state of Texas to explicitly include energy efficiency measures in its NOx-SIP. The OTC has commissioned the creation of a detailed methodology for quantifying the emission reduction impacts of energy efficiency and other clean energy programs. [5] Should the Commission in the future elect to quantify the environmental impacts of energy efficiency, such efforts provide a rigorous basis for doing so.

Energy Efficiency Reduces Customer Bills. Under the assumption that affordability as well as reliability is a Commission goal for the proposed rule, the Commission should give due credence to the unique benefits energy efficiency provides in the affordability of energy. Some analysts view affordability as function of price alone; indeed, we have shown above that efficiency can have significant effects in reducing wholesale market-clearing prices. However, at the consumer level affordability is a function of consumption multiplied by price; thus, if reducing prices merely encourages increased consumption, consumer energy *bills* (as distinct from prices) may not be reduced.

Energy efficiency, by reducing both the average price and the average number of kilowatt-hours consumed, creates twin benefits for energy affordability. Moreover, electricity as a commodity has shown unexpected volatility as market conditions change. It is unreasonable to expect power prices to remain stable and low indefinitely; one of the consumer's best hedges against price volatility, especially given the recent collapse of the energy trading and derivatives markets, is to reduce consumption on an ongoing basis. For example, if a business uses one million kWh annually and its average price increases from five to six cents, its energy bill will increase from $50,000 to $60,000. However, reducing its usage by 20% through efficiency measures cuts its bill from $50,000 to $48,000, even with the price increase. The price increase in this context serves mainly to increase the economic return on the consumer's investment.

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[5] Geoff Keith, David White, and Bruce Biewald. *The OTC Emission Reduction Workbook 2.1: Description and Users Manual.* Synapse Energy Economics, October 2002.

Energy Efficiency Has Been an Important Element of Electricity System Planning. In 1982, the term 'Demand-Side Management' (DSM) was coined at the Electric Power Research Institute to represent a new body of research and practice in the utility field. The 1970s had revealed important new facts about electric system planning:

- The maturing of economies of scale in convention power generation technology meant that new power plants were no longer guaranteed to be more cost-effective than the units they replaced.
- Energy price shocks drove a wave of investment and behavior change aimed at reducing demand; this proved that conventional forecasts of steady and steep demand growth could be widely inaccurate.
- Roger Sant had coined the phrase "least-cost energy services" to represent the experience of American energy users, who were finding that there were cheaper ways than conventional energy commodities to provide the light, heat, cooling, shaft power, and other energy services they wanted. Energy-efficient technology, design, and operating practices began to emerge as significant forces in the U.S. economy.
- Utility regulators realized that a new planning paradigm was needed to manage the risks of high-priced power plants, volatile fuel prices, and fluctuating customer demand.

During the 1980s and 1990s, dozens of states acted on these issues by creating Integrated Resource Planning (IRP) processes, in which utilities were required to examine a wider range of resource options that conventional power generation technology in planning to meet customer needs. IRP typically required utilities to perform DSM potential and resource screening studies to define the least-cost mix of demand- and supply-side resources. The utility resource plans filed under these IRP processes drove significant utility investment in DSM: by the early 1990s, utilities were spending over $2 billion annually on DSM programs. These programs produced savings in the range of 60 billion kWh and 30,000 MW of peak demand annually; these numbers represent about 2 % of total kWh sales and 4% of peak demand.[6]

DSM programs reduced the growth in electricity demand significantly. In the pre-DSM 1970s, for example, electricity demand growth averaged 4.2% annually, despite two recessions and electricity prices that tripled on average. During the 1990s, electricity usage grew at a 2.3% rate, during a decade of high economic growth and flat electricity prices. While many factors affect electricity usage, it is worth noting that demand growth in the 1990s was about two percentage points lower than in the 1970s, and that DSM impacts during the 1990s were in the range of 2% of annual sales.[7]

However, energy efficiency investment has been a casualty of electricity restructuring. As generation markets became fully deregulated and as transmission systems move toward regional, independent operations, state utility commissions have a smaller and smaller purview in which to use energy efficiency as a system resource. The avoided cost

[6] http://www.eia.doe.gov/cneaf/electricity/dsm00/dsm_sum.html
[7] ACEEE staff analysis based on U.S. Department of Energy data from http://www.eia.doe.gov.

numbers for planned generation units that were used as the primary basis for valuing energy efficiency resources became meaningless in many states as generation ownership shifted to unregulated entities. Utilities felt compelled to cut costs to gear up for anticipated competition, and DSM budgets were one of the first areas to be targeted.

DSM program cutbacks reduced investment in energy efficiency by about half from the mid-1990s to the late 1990s. While some states have partially offset these cuts by creating public benefits funds, most of the programs that have been supported by these funds have been broad-based market transformation programs rather than targeted resource acquisition programs. While these programs produce 'system benefits' in terms of demand and bill reduction and pollution prevention in some of the same ways DSM programs did, they are not specifically targeted to reduce peak demand in a transmission-constrained load pocket. Since they are not directly integrated into electricity markets or system planning processes, their potential for addressing key resource needs is less than that of historical DSM programs.

Energy Efficiency Must Be Re-Integrated Into System Planning. The proposed rule anticipates an active, ongoing planning process for transmission systems and aspects of the markets they mediate. We submit that energy efficiency should be explicitly encouraged for use as a resource in transmission system planning and related activities.

We also want to restate the fact that energy efficiency is a distinct type of demand-side resource. There is a tendency in current discussions to lump all forms of 'demand response' into a single category; we submit that this oversimplification is not helpful. Most of what is termed 'demand response' is load management: temporary drops in demand at a customer facility lasting a few hours, on a few occasions per year. Energy efficiency produces more benefits than load management, such as:

- **Efficiency measures can be more reliable than direct load response**. Efficiency measures generally stay in place over a period of years and provide consistent demand and energy savings over that period. The economic load response programs launched by Independent System Operators (ISOs) to date, on the other hand, are dependent on customer decisions to participate, often on the day or the hour the response is needed. Even if the response can be verified by meter, that doesn't make it reliable if the customer decides not to participate. By contrast, efficiency programs that install durable measures such as efficient commercial lighting, high-performance air conditioning, or low-solar-gain windows can be relied on to produce consistent peak impacts year after year.
- **Efficiency programs produce superior air quality benefits**. Load response programs, because they operate for only a few hours, offer little or no air-pollution emission-prevention benefits. Some can even increase overall energy use and pollution: for example, thermal storage programs that operate cooling systems at night can use more energy than conventional systems because of storage losses.
- **Efficiency programs offer greater customer benefits while also benefiting the system**. Customers who can shed load in an ISO load response program may earn significant dollars for the hours they participate. For example, at $250/MWh a

customer could earn $1000 by shedding a 1-MW load for four hours. If the customer participated 10 times per year, they would earn $10,000. However, if the same customer installed an efficient cooling system that reduced peak load by 1 MW and operated at 1000 equivalent full load hours at an average rate of $.07/kWh and a $7/mo/kW ratcheted demand charge, that customer would save $70,000 in energy charges and $84,000 in demand charges each year. Total savings to the customer would be more than 14 times that from the load response program. Moreover, the transmission system operator would also get the same load response benefit.

Specific Comments

The proposed rule creates a new framework for the operation of electricity markets, and for planning the systems and resources needed to sustain these markets. This new framework contains enormous potential to increase energy efficiency in many facets of the electricity industry and of the U.S. economy as a whole. However, important details must be specified in this rule to ensure that the full potential of the energy efficiency resource is enabled. ACEEE's comments are structured to follow relevant sections and paragraphs of the proposed rule.

IV. D. Transmission Pricing. The Commission should make explicit that costs of several kinds, not limited to transmission hardware and facilities, may be recovered via pricing mechanisms. These costs should explicitly include the costs of ITP-operated demand response programs, and demand-response programs should explicitly include energy efficiency as a resource. Within the scope of transmission pricing, ITPs and RSACS should explicitly be enabled to recover costs for energy efficiency and other distributed resources, in tariffs, uplift charges, or through public benefit charges.

IV. F. Day-Ahead and Real-Time Market Services. We support the combined day-ahead and real-time market design approach. It has been shown to create opportunities for load response in exemplary markets such as PJM. However, important issues must be detailed and addressed if the full potential of demand response is to be tapped in these markets.

The most central issue is metering: specifically, the prevailing requirement among ISO load response programs that hourly-interval revenue meters be in place in order for retail customers to be able to participate in load response markets. This requirement effectively excludes more than 90% of retail customers from participating for the foreseeable future, and keeps the majority of demand-response potential from being tapped.

The great majority of customers, notably residential and all but the largest commercial and industrial customers do not currently have interval metering that would meet the requirements of today's ISO demand-response programs. Most of them are unlikely to obtain such equipment in the near future, for cost reasons: qualifying utility revenue metering systems for a typical school facility, for example, can cost on the order of $5,000. There is currently little or no momentum among state commissions to require such metering. In the one case where real-time metering was deployed on a broad basis to residential customers, at Puget Power, the project has been discontinued as economically non-viable.

However, the technology to provide real-time, documented data on customer load response without interval revenue meters is readily available and relatively inexpensive. In fact, ISOs such as PJM currently use such methods in their Active Load Management (ALM) programs. For example, Pepco's *Kilowattchers* program participates in the PJM ALM market, yet none of the participating residential customers is individually equipped with interval metering. Instead, Pepco produces statistically-derived load shape projections based on a sample of customers, whose air conditioners are temporarily monitored at much lower cost than interval metering would entail. PJM accepts the statistically-based load shape approach in this instance, but to date will not accept third-party load shape information from other parties in its demand response programs, even if it is as statistically rigorous as that currently used in *Kilowattchers*.

Third-party monitoring technology could be deployed in demand-response programs at a fraction of the cost of mandating interval revenue meters. The data would be just as reliable as that from utility revenue meters. This data could be used to develop statistically-derived load shapes for several types of energy efficiency and other demand response programs. However, ISO and state rules, often backed by distribution utilities, deny such technology the ability to participate in demand-response markets.

Currently, distribution utilities and states typically supply ISOs customer-class-wide load shapes used to administer financial settlements. ISOs thus have no independent means of evaluating customer load shapes. This is a jurisdictional gap that the Commission should seek to fill. We believe this rulemaking, and the processes that ITPS and RSACs will develop based on it, is an appropriate place to address this problem. We understand that the jurisdictional issues among the Commission, ITPs, states, and LSEs may make this concept appear complex in its implementation. However, it is no more complex than many other aspects of this rule, and we urge the Commission to confront it directly.

We therefore recommend that the Commission state requirements in the final rule that ITPs and their RSACs develop pre-approved methods for load shape development, submission, and approval as part of their planning process for demand-side resources. Further, third parties should be explicitly permitted to submit proposed methods, and the Commission should also explicitly state that the cost of load shape development protocols must be fair and reasonable, and should not be allowed to be raised arbitrarily.

This issue is similar to those revolving around interconnection issues: through those separate proceedings, the Commission has become acutely aware of the need to make the cost and time burdens associated with market entry reasonable, especially to smaller participants. Without creating fair and affordable means of access to the market, the bulk of new resource potential will be blocked from participation, and the Commission's goals for open, balanced, and vibrant markets will not be realized. In this regard, demand response and small generators face similar obstacles and require similar levels of effort to obtain needed relief.

This issue of load shapes also points to the need for consideration of additional market structures. Since statistical load-shape-based approaches cannot realistically participate in day-ahead and real-time markets, ITPs may need to develop annual or multi-year market structures into which demand-response providers may bid. For example, if a demand response provider arranges to replace older air conditioning equipment with high-efficiency systems in 1000 residential customers, and can provide statistical load shape data based on a sample of customers according to an ITP-approved protocol, that provider should be able to bid the peak-reduction value of this program into an ITP-managed market. We recommend that the Commission include a requirement for ITPs and RSACs to develop markets of this kind.

These markets might offer different levels of incentives than the current ISO day ahead/real time markets. We would expect typical incentives would be lower than for real time markets. However, if ITPs encourage efficiency investments with specific peak benefits, they may be able to acquire these resources for lower costs than they would have to pay for real-time load response. For example, if the above-mentioned residential air conditioner program produced one megawatt of capacity benefit, the ITP could pay a lower incentive for this resource than it would have to pay for a megawatt of load response in a real-time market.

IV. G. 3. Regional Planning Process. We agree with the Commission's intent to establish effective regional planning processes quickly as this Rule is implemented. In particular, we support certain principles stated in this subsection:

- (337) "It is neutral with respect to the type of investment market participants may make in response to these price signals." We take this to mean that for an ITP's planning process to be in compliance with the proposed rule, investments in energy efficiency and other demand response resources must face no more obstacles nor be otherwise disadvantaged in relation to conventional transmission facility investment.
- (346) "A regional planning process can identify both the projects that would benefit the planning area and potential alternatives in a fair and unbiased manner…[and]…would evaluate the benefits of alternative proposals and provide an independent assessment of which projects are the most cost-effective and/or have the least environmental impact."
- (347) "The planning process should leave open the question of how and by whom those needs should be met without favoring one solution (whether it is transmission, generation, or demand response) over another. The planning process should be open to all industry segments. Additionally, all entities could propose projects."
- (348) "An Independent Transmission Provider should have the responsibility to issue requests for proposals when the planning process determines that additional resources are needed to serve the regional market. Parties may respond with proposals to expand the grid, add generation (including distributed generation), or implement demand response."

These principles place the ITP effectively in the role of resource portfolio manager for its regional electricity system. We believe this role is an appropriate one, and that ITPs, in partnerships with states through RSACs, can become effective market managers by performing essential planning and coordination services that private interests cannot and will not provide on their own. We recommend to the Commission further study of portfolio management issues as elaborated in the Regulatory Assistance Project's recent report entitled *Portfolio Management: Protecting Customers In An Electric Market That Isn't Working Very Well.*[8] While much of this report is aimed at state-level portfolio management issues, its basic principles apply to many of the issues ITPs and RSACs will face. A principle repeated throughout the report is that energy efficiency is a resource option that must be included in any balanced portfolio.

While we take these principles to be supportive of energy efficiency as a demand response resource, we also recommend that the Commission add more specific requirements to ensure that ITPs, RSACs, and their stakeholders make the best choices for their regions. We address these specifics in our comments on the Long Term Resource Adequacy provisions of the proposed rule. We also recommend that the rule state explicitly that regional transmission planning and resource adequacy planning processes should be coordinated at the ITP and RSAC level to take advantage of potential synergies. For example, a demand response initiative in a transmission-constrained area could be part of both an ITP's regional transmission plan and an LSE's long term resource plan.

IV. J. Long Term Resource Adequacy. (LTRA) We support the intent and general design of the LTRA requirements. We also recommend additional specifics as follows:

- **Resource adequacy requirements should define minimum levels of demand response.** Some ISOs, including PJM, have calculated the levels of demand response that would be needed to avoid potential misuse of market power on the part of generators. We recommend that RSACs, as part of the LTRA planning process, define minimum levels of demand response appropriate to their regional market. We recommend the Commission define guidelines for calculating minimum demand response levels, based on PJM's current methods. In addition, we recommend that LSEs be required to include proportionate levels of demand response in their resource plans.
- **Resource adequacy plans should reflect the full value of energy efficiency.** The Commission should be specific in defining a planning framework that fully captures the costs and benefits of resource options. For energy efficiency, that means that the avoided costs in terms of generation, transmission, distribution, and pollution avoidance should be addressed. Several state integrated resource planning frameworks developed widely-accepted methods for this kind of analysis, and we recommend the Commission require similar kinds of cost and benefit analysis for the planning processes it envisions for ITPs, RSACs, and LSEs.

[8] see full report at http://www.ef.org/documents/pm_final.pdf

- **Resource adequacy plans should address long-term timeframes.** Recognizing the full value of demand-side resources like energy efficiency requires a long-term planning horizon. Efficiency resources can take time to deploy, and their benefits accrue over many years. We thus recommend the Commission require minimum timeframes for long-term resource adequacy plans. We suggest 10 years as a reasonable minimum planning period.
- **ITPs and RSACs should conduct regional resource analyses.** The Commission asks that each region set its own reserve margin requirements. However, part of the process of setting reserve requirements should be a periodic resource assessment process that identifies the technical and economic potential for defined categories of resources. These resource categories should include conventional central station generation, distributed generation, combined heat and power systems, energy efficiency, load management, and interruptible loads. Developing concrete knowledge of resource potential and cost in the region will help ITPs and RSACs evaluate the adequacy of LSE resource plans.
- **Resource plans should meet minimum requirements**. The Commission should set certain guidelines for minimum requirements that must be met for LSE resource adequacy plans to be approved. These minimum requirements should include, but not be limited to:
    1. Plans must include specific resource technical and economic potential analyses. They must, at a minimum define technical and economic resource potential (economic potential to be assessed using a Total Resource Cost test as defined by the California Public Utility Commission's long-standing rules) for a range of supply-side and demand-side resources, including conventional central station generation, distributed generation, combined heat and power systems, energy efficiency, load management, and interruptible loads.
    2. Baseline forecasts must specifically take into account energy efficiency policies and programs in place or expected to be implemented during the planning period. These include building energy codes, appliance and equipment efficiency standards, public benefit efficiency programs, and other end-use efficiency initiatives that affect load forecasts.
    3. Plans must demonstrate that they have identified and procured a low-cost, and low-risk, mix of resources that can reliably meet forecast customer demand. ITPs and RSACs should define diversity, cost, and risk targets based on the known regional resource potential and cost, so that LSEs are encouraged to submit plans that include a mix of resources by size and type, including supply-side and demand-side resources. LSE plans should be evaluated based on the regional assessments described above. If an LSE plan fails to meet targets for diversity, cost, or risk, it should be rejected.

IV. K. State Participation in RTO Operations. Structure and governance of the RSACs and ITPs, and the processes under which they operate, are crucial to the effectiveness of the proposed rule. We appreciate the Commission's specific attention to these issues, and offer additional specific recommendations to ensure that the intent of the rule is carried out in the implementation of these regional organizations.

Regarding the issue of single RSACs versus multiple committees, we recommend the Commission encourage states to use a consultative process in appointing represenatives to RSACs. We suggest that utility commissions, offices of people's counsel, energy offices, and environmental protection agencies be consulted in making such appointments.

We also recommend that RSACs should appoint subcommittees for the issues listed in paragraph 554 of the proposed rule. Each state should appoint representatives to these committees, should oversee their activities, and should receive annual reports from them.

IV. L. Governance for Independent Transmission Providers. We share the Commission's concern in paragraph 557 that "the existing stakeholder process may not provide adequate representation for all market participants and interested parties. The lack of adequate participation may hinder development of alternative energy resources, such as distributed generation, renewable, energy, or demand response programs, since these programs may be contrary to the business interests of certain market participants." As an organization that participates in a wide range of stakeholder processes, we have experienced the negative results that occur when these concerns are not addressed.

We agree with the Commission's recommendation for six defined stakeholder classes, and for advisory committees reflecting these classes. However, we would also reinforce the Commission's proposed principle that no one company, or any of its affiliates, may participate in more than one committee in any one year. This principle must be spelled out in lucid detail, so that committee members must be shown to have no present or past employment, financial relationship, or other association with any entity owned or controlled by an organization with representation on any other committee. We have seen in the past situations where consultants, attorneys, or other individuals, who have a strong history of association with a particular organizations or interests, serve as proxies for these interests while narrowly avoiding classification as "employees" or "affiliates".

We recommend that the Commission establish an appeals process for ITP governance issues. If stakeholders participating in the advisory process believe that the intent of this rule is not being upheld, they should have access to a well-defined and timely process for bringing these matters first to the ITP Board, and then to the Commission if they choose to appeal the ITP Board's decision.

We also urge the Commission to establish a financial support mechanism for stakeholders who do not receive direct and significant financial benefits from the operations of the regional electricity system. These would include public interest representatives, alternative energy providers, and customer representatives. The Commission has no doubt observed the time and resource commitments brought to its own proceedings by parties with large material interests and resources in these matters. The public interest, as well as the interests of customers and the environment, have frequently been under-represented in these proceedings, not because of a lack of commitment, but because of a lack of resources. Most states have addressed these issues, at least in part, by creating an office of people's counsel or similar form of public interest representation. These offices are often supported by electricity system revenues.

We recommend that the Commission specifically include a requirement in the final rule that ITPs set aside funding, beyond their base staffing and operations budgets but included in any costs submitted for collection via tariffs or other system-wide revenue mechanisms, for public interest representation in ITP processes. These funds should be used to reimburse the costs of time spent in and preparing for meetings, travel to and from meetings, and for support analyses needed to participate effectively in ITP processes. We suggest that a charge of at least 0.01 mils per kWh be established by each ITP for these purposes.

Conclusions

ACEEE commends the Commission for its intent to include demand-side resources such as energy efficiency in the proposed rule. Energy efficiency has been shown to be a workable, cost-effective, and reliable resource in electricity markets around the nation over the last two decades. However, restructuring has unraveled the framework that states have used to employ energy efficiency as a resource solution in electricity policy. The Commission has the opportunity in this rulemaking to restore energy efficiency as an effective electricity planning resource. We recommend that the Commission:

- Allow collection of energy efficiency planning, program, and other related costs in transmission pricing mechanisms.
- Address metering and related load profile issues in demand-response market design, so that the majority of customers, who do not have access to interval metering, have the opportunity to participate in these markets.
- Add specifics to regional planning for resource adequacy and related matters so that demand response, including energy efficiency, is given adequate valuation and analysis.
- Set state participation and governance requirements for RSACs and ITPs such that the public interest and energy efficiency expertise are represented adequately, and such that parties with financial interests in system operations are not given undue influence. This may require financial support for parties who do not materially profit from system operations.

We appreciate the opportunity to comment on this important rulemaking, and we look forward to working with the Commission on these issues in the future.