

## NERC News – August 2007

### June 18: A Milestone for Reliability Standards

*A letter from the NERC President*

In the United States, 83 mandatory standards for the bulk power system, comprising over 700 enforceable requirements, became effective on June 18th. Other than a small flurry of news articles, the moment passed with little public fanfare. To the casual observer, it may seem like all is quiet on the NERC front. But like a duck that seems to be gliding smoothly across the surface, do not let the apparent sense of calm lead you to think that our feet aren't paddling very fast. The arrival of mandatory U.S. standards was like a meteor dropping into the ocean far from shore. The resulting waves are on their way. Unlike a Tsunami, however, these waves bring benefits rather than devastation.

**Bracing for the Waves.** The first and largest wave to hit the industry is the group of nearly 4,100 violations of the voluntary standards and associated mitigation plans self-reported prior to June 18. Because these were filed with the regions prior to the mandatory enforcement date, they will not be treated as violations of the mandatory standards as long as the mitigation plans are approved by the regions, accepted by NERC, and then completed as scheduled.

A second and fortunately smaller wave of 300-plus alleged violations is also coming. These violations were reported on or after June 18. The majority of them will eventually become confirmed violations with corresponding mitigation plans, and will be filed with FERC after acceptance by the NERC Board of Trustees' Compliance Committee. Upon approval by FERC, they will become the first group of violations of mandatory standards and enforcement actions under the new ERO as enabled by the Energy Policy Act of 2005.

As you might expect, these waves carry with them an enormous amount of work for NERC and the regions. We must review and ultimately monitor mitigation plans for nearly 4,100 violations of the requirements in the reliability standards. Translating this massive amount of information into a manageable form will in itself require a significant effort.

**Glass Half Full.** I have been asked whether the high number of pre- and post-June 18th violations is good news or bad news. Is the glass half full or half empty?

The answer is clear. Real actions are being taken by users, owners, and operators to improve the reliability of the grid, and that makes the glass half full. Users, owners, and operators are actively reviewing everything they do to ensure they are in compliance with all the standards requirements that apply to them. The passage of mandatory standards by Congress was intended to encourage just that. All we have done today is confirm the wisdom of that decision. Knowledge of these on-going violations cannot be considered bad news unless you believe in the eternal sunshine of the spotless mind.

**Types of Violations.** Here's the breakdown of what is in these early waves of violations.

By and far the largest group of violations is administrative. Of the nearly 4,100 reports of violations, over 2,200 represent situations where the company is performing the necessary tasks

to preserve reliability, but has determined its documentation may not be sufficient to demonstrate compliance during a compliance audit. Some would debate the importance of these requirements within the standards, but I have faith in those who designed and voted for these requirements.

The real significance of this is that every single self-report of an administrative violation tells me someone took seriously compliance with all the requirements in the NERC standards. It is becoming commonplace for companies to thoroughly assess compliance with standards. These self-audits are often done by third parties. We just lost an auditor to a firm planning to provide pre-audit preparation for users, owners, and operators. We can take some comfort that when the users, owners, and operators went looking for violations, most of what they found was administrative.

The second group of alleged violations comes from new players with new requirements coming into compliance for the first time. The effort to identify these users, owners, and operators is long overdue. It is a by-product of the recent changes in law and industry culture. The vast majority of these new players are generation operators, load-serving entities, and distribution providers. For example, we have new balancing authorities who are now recognizing for the first time their mandatory obligations to review emergency plans and exchange those plans with their reliability coordinator, neighboring balancing authorities, and transmission operators.

The third group is users, owners, and operators who have ‘pled guilty’ to a violation of NERC standards but have been found to be in compliance by the regional entities. As we all gain experience with the mandatory standards and enforcement we will see less of this but I suspect there will always be some false confessions—better safe than sorry.

The final group is small, but does include some alleged violations that are serious. These include processes for the recognition and reporting of sabotage events, maintenance of protection equipment, vegetation management, and identifying system operating limits. While all 4,100 violations and associated mitigation plans are being taken seriously, this final group warrants and is receiving special attention.

Overall we are seeing real improvement in the bulk power system. We cannot eliminate all the risks. But we can study them. Our newest engineer, Dr. Jessica Bian, will be doing just that through her work on reliability performance metrics and benchmarking, which will document the reliability improvements that are achieved by users, owners, and operators through the work they do. I am encouraged there is real work underway and more to come.

**Balancing Act.** So, how do we successfully navigate the 10-foot waves from mandatory standards and the associated improvement that goes with them? How do we keep our heads above water despite the pounding waves? How can we be timely, accurate, thorough, and consistent with thousands of violations to process? And how do we make sure we concentrate the majority of our efforts on the few real dangers in the water?

The answer is we must be flexible and achieve the perfect balance that will keep reliability improving and moving forward. We cannot allow ourselves to be overcome by any one particular factor. We must keep our eye on the horizon as well as the waves, the horizon being the overall prize, which is the greatest amount of reliability improvement.

**The Registry.** I would like to explore this need for balance with you in a little more detail, focusing first on the Compliance Registry.

With the regions' help, we now have over 1,700 registered users, owners, and operators. About 90 challenged the designation. Of those, 40 were resolved by the regions without appeal, another 15 by the BOT CC, leaving the balance to be resolved at the regions or come to the Committee. The listing of users, owners, and operators is not an academic exercise — it comes with responsibilities. It is the list we must audit, train, and communicate with on a regular basis.

I believe we have the balance just right for now. Not too many entities, not too few.

**Penalties.** Next up is financial penalties.

Enforcement of reliability is different than market enforcement. If money is lost, you can deal with it imperfectly after the fact.

With reliability, there may be no second chance to get it right. Therefore we must establish a culture of mandatory compliance right from the get go and maintain it all the time.

Consequently we must encourage self-reporting and prompt and effective self-mitigation. We are certainly off to a good start, having received thousands of them. But going forward we must aggressively encourage self-reports with strong mitigation plans. Does this mean there will never be a financial penalty associated with a self report? No. It does mean it will always matter that you self report. We cannot be too severe or too lenient in dealing with self-reported violations. We have to achieve just the right balance.

**NERC-Wide.** These waves of violations are stretching the limits of our data reporting systems. We recognize data reporting is essential to everyone. The systems need to be timely, accurate, thorough and, to drive consistency, they must not be unwieldy. We and the regions have a major task ahead as we deal with this. To be successful we must balance these different needs. We want the data to be comprehensive, but we can't wait six months to get it.

We also have to strike the right balance in how we communicate the facts surrounding these violations, always mindful of the confidentiality rights of users, owners, and operators.

OSHA and EPA in the U.S., and Transport Canada, all have cultures of enforcement. The world does not come to an end because you, without intent to do so, violate a rule. You fix the problem, pay the penalty, and move on, with all parties knowing the system is safer or cleaner as a result. Nothing we do will require more of a delicate balancing act than establishing the right culture of enforcement in the electric industry complemented by a fair, fact-driven, release of information to the public. Our first test of this will come when we release the information associated with this first wave of confirmed violations.

With respect to the standards themselves, we may have the greatest challenge of all. We must make the standards precise without becoming overly prescriptive. They must be concise yet crystal-clear. They must be actionable, and the entities they apply to must be clearly defined.

This balancing act is being felt in other areas of NERC's business as well.

We need to move quickly over the next three years to complete the standards work plan, but we cannot rush things—we must do a comprehensive, thorough job.

While we focus on reaching compliance with the current standards, we also are thinking about how to move up the “stair steps” of improved reliability assessments without losing our balance by trying to leap to the top in one jump.

Finance and Human Resources have to balance the size of the budget and staff that is growing at a double-digit rate with the need to assimilate and train the staff we have, many of them relatively new.

The Transmission Forum must balance their need for total confidentiality with the greater value achieved by sharing appropriate information with NERC and stakeholders.

The Readiness teams must create value without adding another layer of compliance.

For Situation Awareness, it means we must be aware of everything happening on the bulk power system yet not interfere with operations or create duplicate systems. It also means we must balance the need to distribute vital information with our enforcement responsibilities.

Overall, I think we have it about right. The aftershocks of the meteor dropping into the ocean haven't upset our balance. We look to all of you to keep nudging us patiently in the right direction.

*Rick Sergel*

## **NERC Seeks Opinions on Reliability Issues**

In July and August, NERC surveyed a broad range of utility users, owners, and operators at various levels of leadership and management to find out what they consider the most important issues affecting the reliability of the bulk power system. The survey results will help NERC develop the appropriate reliability metrics to display on our Reliability Dashboard, and improve our Reliability Metrics and Benchmarking Program overall.

NERC received 236 responses during the three-week survey period that ended August 7. We will publish a summary of the survey results by the end of this month, and include the summary in the September NERC News. Individual survey responses are confidential.

Contact: [Jessica Bian](#)

## **Encouraging Compliance Through Self-Reporting**

June 18 marked the beginning of enforceable standards under Section 215 of the Federal Power Act for the 83 FERC-approved standards in the United States (June 25 for facilities designated as qualifying facilities).

NERC's process for monitoring compliance with the approved reliability standards requires that each owner, operator, and user of the bulk power system responsible for complying with the reliability standards register with NERC. As a result, NERC, through the regional entities, has identified 1,563 organizations responsible for complying with the standards under Section 215 of the Federal Power Act. As a comparison, before compliance became mandatory and enforceable, NERC monitored voluntary compliance with only 200 organizations, traditionally the members of the NERC regions.

## **Violations reported before June 18**

To effectively monitor the compliance of so many organizations, NERC has encouraged organizations to evaluate their own compliance with these standards, and then self-report their violations and provide mitigation plans for NERC's approval prior to the effective date of the

standards. In return, NERC holds all penalties or sanctions in abeyance while that organization implements its approved mitigation plan.

The program of self-reporting violations in advance of the effective date of the standards is very successful. To date, NERC has been notified of over 3,500 violations and mitigation plans that were primarily self-reported to the regional entity before June 18. NERC is reviewing those mitigation plans, and, once approved, submits those plans to FERC.

NERC compliance staff has reviewed all of the reported violations to assess their risk on the reliability of the bulk power systems. Most of the violations identified have been judged to pose little or no risk; indeed, over one-half of the violations are related to the documentation necessary to support a compliance audit. Further, the bulk of the violations are from registered entities that were not part of the former voluntary program.

For those violations that do pose a reliability risk, NERC, through the regional entities, is following up to make sure the non-compliant organizations quickly implement their mitigation plan.

### **Enforceable violations reported after June 18**

NERC has received notice of over 300 violations of NERC reliability standards from the regional entities since June 18. Most of these violations resulted from reporting just after the enforceable date for the standards by the registered entity. As we found with the pre-June 18 violation reports, most of these violations are documentation related and from registered entities new to the process. NERC and regional entity staff have reviewed these violations and believe they do not have a significant impact on bulk power system reliability. A confidential report was prepared for each violation and submitted to FERC in accordance with FERC's orders, rules, and regulations.

Contact: [Mike DeLaura](#)

## **System Operator Certification and Continuing Education**

### **Continuing Education Transcript Updates**

Many training providers have been manually loading system operators' continuing education hours into our new database. We continue to test the "bulk upload" capability that will allow training providers to input these transcripts more efficiently. The encouraging news is that several training providers have been able to bulk upload the transcripts, and are sharing their "lessons learned" with others in the process. In addition, we are helping other training providers who are continuing to use the manual process to upload their transcript data. We encourage all system operators to periodically check their accounts for these transcripts.

Contacts: [John Theotonio](#) and [Lori Chances](#).

### **New Personnel Certification Governance Committee Members**

The NERC Board of Trustees appointed Rod Byrnell, BCTC, and Keith Comeaux, Louisiana Generating, to the PCGC. We welcome these new members and expect they will be great additions to the committee.

Keith Comeaux is the compliance manager for Louisiana Generating and brings his experience from participating in the SPP operator training working group, SERC operator training group, NERC exam working group, and NERC Personnel Subcommittee. He was appointed to a one-year term starting November 1, 2007 to fill an open position on the committee.

Rod Byrnell has experience in all phases of the industry including generation, transmission, and distribution. He has been employed by British Columbia Canada for over 32 years and is currently a system operations supervisor. Rod has participated on the NERC Personnel Subcommittee and the WECC Operator Training Subcommittee, and is a NERC continuing education reviewer. He was appointed to a two-year term on the committee starting November 1, 2007, replacing Pierre Paquet, HQ TransÉnergie, as the committee's Canadian representative. Pierre will be resigning from the PCGC at the end of his term October 31, 2007.

### **PCGC to appoint new Exam Working Group members**

The PCGC will appoint two new members to the EWG during its August 21–22, 2007 meeting.

Contacts: [Rick Byrne](#) and [Rhonda Tuck](#)

### **FERC Issues NOPR on Cyber Security Standards**

On July 20, 2007, FERC released the long-awaited Notice of Proposed Rulemaking concerning NERC's Cyber Security Standards (CIP-002 through CIP-009). In the NOPR, FERC is proposing to adopt the eight standards as mandatory and enforceable, but is proposing to request changes be made in all of them. They are not proposing to change the implementation plan that was submitted along with the standards. FERC is, however, requiring that the term "Reasonable Business Judgment" be removed from the standards prior to 2009, and is requesting additional changes to the use of Risk Assessments and Technical Feasibility within the standards. Details on the additional proposed changes are described in the NOPR text.

All industry participants are encouraged to read the NOPR, and file comments expressing their opinions and concerns with the provisions of the proposed rule. All comments are due to FERC by October 5, 2007. NERC will be filing comments, and expects to publicly release an initial draft of their comments in mid-August.

#### [NOPR](#)

[Federal Register announcement](#), August 6, 2007

Contact: [Scott Mix](#)

### **Staff**

**Joe Conner, CFO**, will be leaving NERC at the end of the year. Joe has purchased a business that he will operate as the CEO. We thank Joe for his immeasurable contributions to NERC, taking it from Council to Corporation to ERO, completing business plans and budgets and cross-border allocations, billing and collecting revenue, working tirelessly with the regions, while simultaneously managing all the financial and business activities of NERC from accounts receivable to taxes. More importantly he became a critical part of the management team, playing a role in almost every aspect of NERC operations. We all congratulate Joe and wish him well in his new venture.

NERC will begin the search for a candidate to replace Joe within the next couple of weeks. Keep an eye out for the job description on our [Career Opportunities Web page](#).

**Gerry Adamski** was appointed by the Board of Trustees, and at the recommendation of Rick Sergel, an officer of the corporation in his new role as vice president and director of standards. Gerry came to NERC from Baltimore Gas and Electric in 2004. He started as a readiness evaluation coordinator and later became director of readiness. Gerry moved to the Reliability Standards Program as director in early 2007. Congratulations Gerry!

**Earl Shockley** joins the NERC staff on August 13 as a regional compliance program coordinator reporting to Cherie Broadrick. Earl previously worked for the Tennessee Valley Authority, Seattle City Light, and San Diego Gas & Electric Company.

Contact: [Heather Gibbs](#)

## Demand-Side Management: Reliability Considerations

A special report by [Mark G. Lauby](#), Manager, Reliability Assessments.

### Introduction

Demand Response is increasingly viewed as an important resource to meet the growing demand for electricity in North America, while at the same time, addressing green house gas along with CO<sub>2</sub> legislation. Demand Response is a subset of the broader category of end-use customer energy solutions known as Demand-Side Management (DSM). In addition to Demand Response, DSM includes energy efficiency programs. This Demand Side Management evaluation is concentrated on the influence of Demand Response on reliability assessment and therefore, focused on peak demand reduction rather than overall energy. The long-term reliability benefits include reducing supply-side and transmission requirements to meet internal demand. Demand Response becomes a resource supplementing reserves, along with operational reliability benefits providing operating reserve and flexibility.



Demand Response programs require substantial investment in advanced metering enabling two-way customer communications, measure response and validated participation. Demand can therefore be managed for operational reserves as well as long-term planning reserves. This metering/communication system investment must be recognized along-side other investments as part of overall bulk power system rejuvenation. Increased certainty on the predictability of customer participation, especially for voluntary programs, is required as part of the justification of these investments.

This paper embraces the definitions of Demand Response as proposed by the U.S. Department of Energy in its February 2006 Report to Congress<sup>1</sup> and adopted by the Federal Energy Regulatory Commission (FERC) in its August 2006 “Assessment of Demand Response and Advanced Metering”<sup>2</sup>:

*“Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale prices or when system reliability is jeopardized.”*

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<sup>1</sup> FERC Staff August 2006 Report: “Assessment of Demand Response & Advanced Metering”  
[http://www.ferc.gov/legal/staff-reports/demand-response.pdf#xml=http://search.atomz.com/search/pdfhelper.tk?sp\\_o=1,100000,0](http://www.ferc.gov/legal/staff-reports/demand-response.pdf#xml=http://search.atomz.com/search/pdfhelper.tk?sp_o=1,100000,0)

<sup>2</sup> U.S. Department of Energy, “Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them.” A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February 2006 (February DOE EPAAct Report).

FERC noted that Demand Response, using this definition, can be divided into two categories: incentive-based demand response and time-based rate programs. Each of these programs has unique aspects influencing the electric utility industry's ability to use the associated programs to reliably plan and operate the bulk power system.

The FERC suggested "*The potential immediate reduction in peak electric demand that could be achieved from existing demand resources is between three and seven percent of peak demand in most regions.*" This represents a significant resource for meeting demand using existing Demand Response programs. Expanding the penetration of these programs or designing new ones may result in an even greater resource impact.

### **NERC Data Collection**

The North American Electric Reliability Corporation (NERC) collects two quantities for on-peak megawatts (MW) for Seasonal (Biannual for Summer & Winter) and Long-Term (10 years) Reliability Assessment Reports: Direct Control Load Management and Interruptible Demand.

As NERC's long-term analysis reports are forward-looking, the remainder of utility DSM programs is captured as part of the Internal Demand, defined as:

**Internal Demand<sup>3</sup>**: is the sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. (Note: please use integrated hourly demand values.)

*Internal Demand includes adjustments for utility indirect demand-side management programs such as conservation programs, improvements in efficiency of electric energy use, rate incentives, and rebates. Internal Demand should not include Stand-by Demand and should not be reduced by Direct Control Load Management or Interruptible Demand.*

Respondents to NERC's Seasonal and Long-Term Reliability Assessment data requests, modify the demand curve to accommodate a variety of demand response programs (such as time of use, real-time pricing, etc.) which is specifically helpful when forecasting future Internal Demand. To afford comparative analysis, these same quantities are also collected as part of the forecasted seasonal Summer/Winter Reliability Assessment data requests.

### **The Impact of Demand Response on Reliability**

As the industry's use of Demand Response changes, NERC's data collection and impact assessment of these programs will change highlighting those that can influence bulk power system reliability.

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<sup>3</sup> NERC: "Instructions for NERC Summer Assessment Data Reporting"

Figure 1 shows the kinds of Demand Response Programs, followed by a brief description of the Demand Response subcategories categorized as described in FERC’s report<sup>4</sup>. Where data is collected for NERC’s seasonal and long-term reliability assessments, the program description was modified to reflect NERC’s nomenclature. Comments are provided on each program’s influence on bulk system reliability.

As with any demand-side management program, experience is needed to determine program requirements and expected demand resource available to manage the balance of transmission, supply and demand. In some cases, the demand response programs are helpful for short-term reliability measures, though unclear regards the long-term impacts on reliability. The impact of demand response on this balance and bulk power system reliability requires further study.

Many of the programs are not unique to organized markets and can be applied in any electric utility setting.

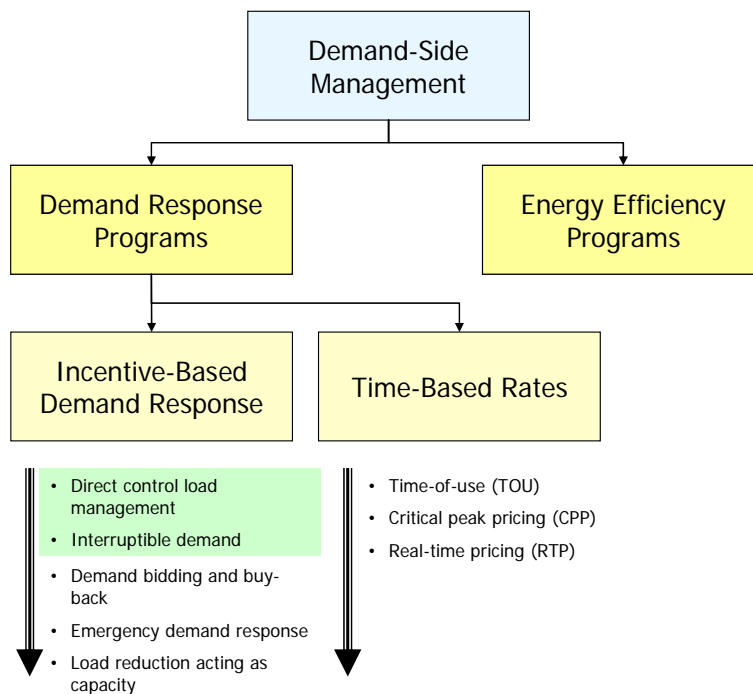


Figure 1 - DSM Programs: Focused on Demand Response

### Incentive-Based Demand Response Programs

These programs include an inducement or incentive for customer participation and they provide an active tool for load-serving entities, electric utilities or grid operators to manage their costs and maintain reliability. Some existing incentive-based programs are:

- Direct Control Load Management
- Interruptible Demand
- Demand Bidding/Buyback
- Emergency Demand Response
- Load Reduction Acting as Capacity
- Ancillary-Service Market

Each is described below with their associated reliability benefits.

<sup>4</sup> FERC Staff August 2006 Report: “Assessment of Demand Response & Advanced Metering” Chapter IV, Existing Demand Response Programs and Time-Based Rates

### **Direct Control Load Management<sup>5</sup>**

NERC's Seasonal and Long-Term Reliability Assessments collects data on Direct Control Load Management, defined as:

The magnitude of customer demand that can be interrupted at the time of the Regional Council seasonal peak by direct control of the System Operator by interrupting power supply to individual appliances or equipment on customer premises. This type of control usually reduces the demand of residential customers. Direct Control Load Management as reported here does not include Interruptible Demand.

Direct control load management refer to programs where the utility or system operator remotely terminates or cycles a customer's equipment on short notice to address system or local reliability contingencies in exchange for an incentive payment or bill credit<sup>6</sup>. These programs have been in place for many years and utilities and system operators have gained sufficient experience to reflect them in both operating procedures and resource plans. The actual benefits vary by customer type, geography and climate. Therefore, expanding its application must be focused on experience to obtain the desired reliability benefits. As existing programs are expanded or new programs created, their actual characteristics should be factored into planning and operating activities.

### **Interruptible Demand<sup>7</sup>**

NERC's Seasonal and Long-Term Reliability Assessments also collects data Interruptible Demand, defined as:

The magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Regional Council's seasonal peak by direct control of the System Operator or by action of the customer at the direct request of the System Operator. In some instances, the demand reduction may be effected by direct action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions. For example, demands that can be interrupted to fulfill planning or operating reserve requirements normally should be reported as Interruptible Demand. Interruptible Demand as reported here does not include Direct Control Load Management.

Customers on Interruptible Demand programs receive a discount or bill credit in exchange for agreeing to reduce load during system events. If customers do not curtail, they can be penalized. Note that Interruptible Demand Programs are different than Emergency Demand Response and Load Reduction Acting as Capacity program alternatives as they are offered by a load-serving

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<sup>5</sup> NERC: "Instructions for NERC Summer Assessment Data Reporting"

<sup>6</sup> FERC Staff August 2006 Report: "Assessment of Demand Response & Advanced Metering" Chapter IV, Existing Demand Response Programs and Time-Based Rates

<sup>7</sup> NERC: "Instructions for NERC Summer Assessment Data Reporting"

entity or electric utility which implements the program. The application of Interruptible Demand programs is used, though not exclusively, for customers who do not have obligations to provide service (Hospitals, schools, etc.) or 24/7 continuous process operations. Though Interruptible Demand programs have been in place for decades, there is concern about the sustainability and reliability of the resource. For example, the expected participant loss is 3%-5% each time Interruptible Demand programs are exercised, influencing long-term assumptions on program participation.

### **Emergency Demand Response Programs**

Emergency Demand Response programs provide incentives for customers to reduce loads during reliability events, though the curtailment is voluntary. No penalty is assessed if customers do not curtail, and the rates are pre-specified, though no capacity payments are received. This program is typically offered by Independent System Operators/Regional Transmission Organizations (ISO/RTO), though they are also offered by electric utilities. They are voluntary and part of emergency procedures. Generally, Emergency Demand Response is not included in Internal Demand data and NERC does not collect this data. Operators can not predict with certainty load curtailment amounts, and planners do not attempt to forecast their influence when developing future system alternatives.

### **Load Reduction Acting as Capacity**

Customers commit to providing specific load reductions during events in return for payments and are penalized if they do not comply. They are offered a firm, quickly deployed resource (both emergency operating procedure and a mid- to long-term supply option) which can be forecasted for operations and planning. Operating experience is needed to forecast the affect on short-term and long-term bulk power system reliability.

### **Demand Bidding/Buyback Programs**

Demand Bidding/Buyback Programs enable large consumers to offer specific bids or posted prices for specified load reductions. Customers stay at fixed rates, but receive higher payments for load reductions when the wholesale prices are high. There is ongoing discussion to determine the entities responsible to pay successful customer bidders. Until this review is complete, it is difficult to determine the operational and planning reliability benefits.

### **Ancillary Services**

In some organizations, this program is called Load Acting as a Resource (LaaR). Consumers bid load curtailment for operating (i.e. spinning) reserves. Successful bids are paid as standby reserves and if required are paid spot market energy prices to curtail. To participate, customers are pre-qualified having under-frequency relays set by the electric utility, include integral demand recorders and must be able to curtail load quickly when events occur typically in minutes rather than hours. This is juxtaposed to longer duration response for peak-shaving or price signal responses. Ancillary Services are focused on operational reliability as a high probability resource, though planners can deploy similar concepts measuring long-term and seasonal reliability when evaluating standard criteria (i.e. N-1, etc.) and reserves.

### **Time-Based Rate Programs**

This category of Demand Response Programs, which can link retail and wholesale markets, has recently received a high level of attention. Retail consumers obtain a price signal reflecting the costs of production and delivery which provides a vehicle to deploy resources more efficiently. This characteristic, as the programs are generally tailored for mass markets, has the potential to reduce or shape demand to balance electricity use and overall costs. There are three prevalent Time-Based Rate Programs:

- Time of Use Rates (TOU)
- Critical Peak Pricing (CPP)
- Real-Time Pricing (RTP)

#### **Time-of-Use Rates (TOU)**

The most widespread time-varying program for residential electric consumers, Time-of Use (TOU) Demand Response are pre-set offerings for a wide variety of time-periods: from seasons to time-of-day depending on the desired application. The pre-set offering reflects the underlying costs for production in hopes that consumers will reduce/curtail their use during the higher priced time-periods. Many utilities now require their larger customers to use TOU Demand Response. To deploy TOU, investment in meters is required to enable time-stamped billability. Consumers can change their electricity use behavior if price differentials are substantial. There is a multifarious experience with TOU rates with varying levels of success, as results can be hard to predict. Load reduction associated with TOU programs are reflected in actual load recordings and embedded in load forecasts.

#### **Critical Peak Pricing (CPP)**

A new form of TOU relies on very high prices during critical peaks rather than average TOU. The offerings are pre-set, but dispatched dynamically on short notice when needed. Because it is price-based to reflect extreme system stress, CPP offerings are equally a reliability based Demand Response vehicle. Data indicates customers do react to reduce/curtail load during the system stress events if appropriate price signals are sent through the CPP. As most proposed CPP programs are currently voluntary, more operating experience is needed. Currently the character of penetration and customer churn rate uncertainty makes it difficult to determine their long-term reliability benefits.

#### **Real-Time Pricing (RTP)**

Prices in this program continuously vary reflecting wholesale prices. RTP are not pre-set and are provided hourly and/or day-ahead for pre-planning. RTP provides a direct link between wholesale and retail markets supplying a price-responsive calibration to the electricity market. Further, RTP programs can also enable reduced unit construction as planners and operators can depend on reductions of demand during high-priced hours. As with CPP rates, RTP programs are currently voluntary, again making the impact uncertain until further experience is gained by system operators.

## NERC's Next Steps on Demand Response

There is a large potential for demand reduction and subsequent reliability benefits of Demand Response as noted in FERC's report<sup>8</sup>. Advanced applications of electricity such as with Plug-in Hybrid Electric Vehicles (PHEV) which can act as a load and mobile storage element (demand and supply) will add new requirements of the bulk power system, as well as offering supportive capacity. Clearly, more load control for planners and operators is required to support the multifarious applications and wisely manage load growth, while at the same time meeting the regulatory requirements promulgated by society.

For example, as demand grows, utilities are beginning to mandate implementation of load control abilities to improve not only the reliability/adequacy of the power system, but also as a first response to large-scale disruptions promulgated by events such as large storms, earthquakes and nefarious acts. Many of these events can result in long-term electric disruptions. The ability to differentiate between essential and non-essential demand is a critical enhancement to adequately and verifiably serve essential loads providing for security and health while system repairs take place.

It is upon this platform that additional services can be provided to serve reliability concerns, integration of new supply-side options and economic benefits.

In the mean time, more operating and planning experience is needed with the specific character and reliability of many of the Demand Response programs to fully appreciate their potential and clarify the uncertainty associated with potential reliability benefits. As significant infrastructure investment is required, planners need to understand the scalability of pilot projects reflecting reliability improvements.

Demand Response incorporation into resource adequacy assessment should be better understood by the industry. In some cases, it may be best to consider a subset of the programs like committed resources, while other programs as uncommitted. It is important to forecast their growth over the next decade and the influence of customer choice on program participation. These are key characteristics required to ensure that the reliability benefits can be assessed, and reflected appropriately, without double-counting both as internal demand and potential resource.

NERC has formed a Demand-Side Management Task Force, reporting to the Resource Issues Task Force focusing on the influence of demand-side management on reliability. Recommendations are due to NERC's planning committee by the end of 2007.



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<sup>8</sup> FERC Staff August 2006 Report: "Assessment of Demand Response & Advanced Metering"