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The program materials pose the question, “Is it possible to achieve both workably competitive markets and acceptable levels of reliability?”

Stated another way, “Given that we must have a reliable system, is it possible also to have competitive markets?” My short answer is, “Yes, competitive markets should even make resolution of some reliability problems easier, but . . ..” The “but” is that the bulk electric system has physical limits and, as August 14 demonstrated, we overlook those physical limits at our peril. This paper describes what NERC is doing to maintain acceptable levels of reliability. I look forward to the discussion to explore the appropriate relationships between reliability and competitive markets.

When I speak of NERC, I mean the entire NERC community. NERC has a staff of about 40 — NERC’s strength is the large number of industry volunteers (literally hundreds) who participate in the whole range of NERC activities. I also include those who operate the system in the hundreds of control centers across North America. NERC itself has no operating responsibility.

NERC is a not-for-profit organization formed after the Northeast blackout in 1965 to coordinate the planning and operation of the interconnected electric grid in North America. NERC’s mission is to ensure that the bulk electric system in North America is reliable, adequate, and secure. NERC’s members are ten Regional Reliability Councils that account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. An independent board of trustees, elected by the stakeholders, governs NERC. That balanced stakeholder committee includes investor-owned utilities, municipal utilities, rural electric co-operatives, independent power producers, power marketers, federal power marketing administrations, large and small end-use customers and regulators. It includes both Canadian and U.S. interests. NERC is owned by and receives its funding from the ten Regional Councils. The Regional Councils also have broad membership from the whole range of stakeholders.

NERC engages in a number of activities in pursuit of reliability: We set reliability standards through an industry consensus process. We monitor compliance with standards, but we presently have no enforcement authority. We provide education and training resources for system operators. We periodically report on the adequacy of the installed and planned generation and transmission to meet expected demand in different parts of North America. We facilitate the exchange of reliability information among the operators through private communications systems and common modeling systems. We support

[1] These remarks reflect my personal views and do not necessarily reflect the views of the North American Electric Reliability Council or its Board of Trustees.

operation and planning activities by maintaining databases on generator unit performance and electricity supply and demand. We certify reliability organizations and individual system operators. We coordinate activities to safeguard the bulk electric system from cyber and physical threats and serve as the electricity sector's information sharing and analysis center, working with the Department of Homeland Security.

What is Reliability?

The term "reliability" means different things to different people. For the consumer reliability means, "Does the light come on when I flip the switch?" For a manufacturer, "Does a momentary surge or blip cause me to lose a whole production run of computer chips I was manufacturing?" For an independent power producer or a marketer, "Does my transaction go through? Or do I need to make alternate arrangements (and incur higher costs) to deliver power to my customer?" Depending on what aspect of reliability is considered, the relationships to a competitive market and nature of the reliability issues one must deal with in support of competitive markets can be very different.

For NERC, reliability has two dimensions: operating reliability [2] and adequacy.

Operating Reliability

"Operating reliability" means assuring that all elements of the bulk electric system are within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of that system will not occur as a result of sudden disturbances such as electric short circuits or unanticipated failure of system equipment. It also means planning, designing, and operating each portion of the bulk power system in a manner that will promote reliable operation of interconnected systems and not burden other interconnected systems. For the bulk electric system operating in real time, there are no choices that individual customers can make about the level of reliability they would like to have. It's a common good. The transmission grid is either operating reliability for everybody, or it's not there for anybody.

We generally operate the bulk electric system in a "first contingency (sometimes referred to as N-1)" mode. That means the system can withstand the loss of its single largest element (whether that's a generating unit, transmission line, or transformer) and still remain stable and not overload any other element in the system. Operators continually run contingency analyses, looking ahead at various what-ifs. Should a contingency occur (and that happens every day on the grid), operators must immediately adjust the system so that it can withstand the next contingency.

This is the area where NERC's rules operate, setting the standards by which the grid is operated from moment to moment, as well as the standards for how transmission facilities are planned. By planning I mean the things that need to be taken into account when one

[2] The term "operating reliability" has replaced the term "security" in the NERC lexicon. Post September 11, 2001, the term "security" is now reserved for discussions of protecting the bulk electric system from physical and cyber attack.

plans and constructs an integrated system that is capable of being operated reliably. The NERC standards do not design where facilities go, either transmission or generation. They do indicate what components and planning must be built into the system if it is to be capable of reliable operation. And operating reliably places limits on the amount of power that can be transferred across the system.

Congestion Management

One of the principal tasks for those operating the interconnected grid is dealing with the congestion that inevitably arises on the system. When the telephone system is congested, you get a busy signal. When the highway system is congested, traffic backs up and it takes longer to get where you're going. When the air traffic control system is congested, you can sit on the taxiway for extended periods in a ground hold. When a transmission line is overloaded, absent operator intervention, power continues to flow on the line. If the limit is a thermal one, the line will eventually sag into an underlying object or burn down. If the limit is a stability limit, the system is at risk of collapse.

Operators must deal with congestion both ahead of time and in real time. Congestion management is a three-letter word, whether you spell it LMP (locational marginal pricing) or TLR (transmission loading relief). Where an LMP-based market exists, the operator uses a security-constrained, [3] bid-based algorithm to determine which generators will run in each hour the following day. "Security-constrained" means that none of the physical limits of the transmission system are violated, i.e., that every element of the system is within its first contingency rating. In theory, the LMP dispatch should take account of all limits in the network, including those outside the LMP footprint. In practice, that is not always done. Then in real time the LMP operator monitors flows on the system and redispatches generation as congestion arises on the system, either because demand is different from what was projected the previous day or because of unexpected outages of generation or transmission. The redispatch is accomplished by price signals the operator sends to each generator, at five-minute intervals.

In the non-LMP situation, the transmission operator grants transmission reservations to the extent of available transfer capacity, on a contract-path basis. Because power flows along all paths between two points on the system (in inverse proportion to the resistance on each path), actual flows do not match the contract path. When a transmission customer wants to actually use the transmission it has reserved, the customer submits an electronic tag identifying the point of receipt and point of delivery for the transaction, the amount of the transaction, and start time and duration of the transaction. Transactions can be submitted as late as 20 minutes before the hour at which they are to begin. On a day-ahead basis, the transmission operator analyses the system, based on tags submitted and its expected use of the system to serve its own customers, to make sure that all elements of the system will remain within their operating limits. The operator repeats the contingency analysis with updated information as he moves into the day of delivery.

[3] This is one instance where the pre-September 11th meaning of "security" is still used.

In 1997, NERC established reliability coordinators to deal with the analysis and handling of congestion on the system, because individual control area operators didn't have enough information, or a wide enough look, or the capability, to deal with the congestion that was arising. The reliability coordinators also perform a contingency analysis on a day-ahead and next-hour basis. If it looks as though congestion (or an overload) may occur on a particular flowgate, the reliability coordinator may initiate a TLR Level 1 by means of a posting to all market participants, which is simply a warning that the flowgate is expected to be at its limit later in the day. If the loading continues to increase, curtailment of transactions may be necessary. New transactions may be held (TLR Level 2) to prevent an operating limit violation from occurring. If an operating limit violation does occur, transactions must be curtailed to eliminate the violation. The curtailments follow the priorities established by FERC in its open access transmission tariff. Non-firm transactions are curtailed first (TLR Level 3); firm transactions come last (TLR Level 5). When curtailment is necessary, the reliability coordinator obtains a list of transactions to be curtailed from the Interchange Distribution Calculator (a computer model of the current topology of the Eastern Interconnection containing the tags for all the transactions that are currently flowing). The IDC calculates the impact of all transactions on the flowgate in question and returns a list of the transactions with a greater than 5 % impact on the flowgate, sorted by priority. The reliability coordinator then orders curtailments based on that list, according to the FERC-established priorities (including the FERC requirement that all transactions of the same service priority should share *pro rata* in the curtailment). Note that curtailing transactions by TLR causes a redispatch of generation on the system, with some generators lowered as particular transactions are curtailed and other generators are raised to provide replacement power. No end-use customer loses service in this situation.

Congestion is resolved through redispatch of generation in both LMP and TLR areas. It's just that TLR is a blunter, less nuanced tool. And congestion is increasing in both LMP and TLR areas. It just shows up differently: As increased congestion charges in the one case, more TLRs in the other. The location of the TLRs is no surprise, either. They generally are located in a band from east to west in the central part of the country. Examining a map of the transmission system reveals that this band tends to be where connections between utilities are not robust. It's also the part of the transmission system that serves as the crossroads for power flows moving north to south, south to north, west to east, and east to west.

Weather diversity across the continent often frees up generation resources in one area prompting transfers to serve demand in another. For example, 2000 saw a significant increase in the number of TLRs as heavy north-to-south power transfers occurred in the central United States, spurred on by extended temperature diversity (cool in the north, hot in the south), which freed up resources for export.

But the TLRs must be kept in context. November 2003 is the latest month for which information is readily available. During November the total number of energy schedules that were tagged into the Interchange Distribution Calculator was 523,528. The number of schedules curtailed by TLR was 17, 384. The vast majority of those were non-firm transactions. For all of 2003 (through November 14), we counted about 50 Level 5 TLRs, i.e., curtailments of firm transactions. The total energy scheduled [4] in November was 67,692 GWh. The total energy cut by means of TLRs was 192 GWh. The actual energy flow post-curtailment (as a percentage of scheduled energy) was 99.72 %. During the period May through October 2003 that percentage was closer to 99.5 %. I don't have equivalent information on the amount of congestion or congestion charges in areas where congestion is managed through LMP.

Even though TLRs affect a relatively small portion of total energy flows, for the particular market participant whose transaction is curtailed, the consequence can be significant. For that reason, it is important for TLR that the rules and processes under which it occurs be clear, that market participants perceive that the system is fair and have assurance that the procedure will be administered in an impartial, independent, and transparent manner. Through the NERC website, market participants have access to the operating limits and actual flows on each flowgate in real time. Market participants can also see a graphic display of the transactions, aggregated by curtailment priority, with a greater than 5% impact on a particular flowgate, including an indication of the portion of the loading due to net energy to native load customers. They can also see where their particular transaction is in the stack. Reliability coordinators post the currently effective TLRs on the NERC web site in real time, and complete logs of each TLR event are posted for inspection after the fact. Eleven of the eighteen reliability coordinators in North America are independent. All reliability coordinators adhere to a standard of conduct that requires a separation of reliability coordinator personnel from marketing personnel at both the wholesale and retail level. NERC audits the reliability coordinators on a regular basis; how the reliability coordinator is assuring the independent functioning of its personnel is one focus of the audit. Those audit results are posted to NERC's web site.

Adequacy

"Adequacy" means the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. NERC periodically assesses and reports on the adequacy of the generation and transmission that make up the bulk electric system. NERC does not set rules for adequacy. Various measures of adequacy exist. A commonly used measure is the one-day-in-ten-years standard. That is to say, one can expect the installed capacity of the system, taking account of planned and reasonably expected unplanned outages, to be able to meet the customer demand on the system on all but one day in ten years. We saw that kind of limit illustrated this past week in New England, as New England set a new winter peak demand record during the cold snap. One of the New England companies announced it was likely it would need to initiate rotating blackouts (planned, relatively short-duration disconnections of blocks of customers) because it anticipated not having sufficient

[4] That is, the energy scheduled to flow, based on tags submitted to the Interchange Distribution Calculator. The IDC covers only transactions between control areas in the Eastern Interconnection.

generation to serve its entire load. As it turned out, appeals for voluntary conservation throughout New England enabled the company to avoid initiating the blackouts.

NERC has just released its latest reliability assessment, covering the period 2003 through 2012. NERC believes that resource adequacy will be satisfactory in the near term (2003–2007) throughout North America, provided new generating facilities are constructed as anticipated. Electricity demand is expected to grow by about 67,000 MW in the near term. Projected resource additions over this same period total about 89,000 MW, depending upon the number of merchant plants assumed to be in service. Even though overall resources appear adequate, generation additions and resulting capacity margins are not evenly distributed across North America.

Resource adequacy in the long term (2008–2012) is more uncertain, because information is harder to come by. However, if current trends continue (i.e., new merchant plants are brought online as the need for them approaches), long-term resource adequacy should be satisfactory.

As for transmission, we expect the North American transmission systems to perform reliably, assuming people follow the rules. However, in some areas the transmission grid is not adequate to transmit the output of all new generating units to their targeted markets, limiting some economy energy transactions but not adversely impacting reliability. Portions of the transmission systems are reaching their limits as customer demand increases and the systems are subjected to new loading patterns resulting from increased power transfers caused by market conditions and weather patterns. Operating procedures, market-based congestion management procedures, TLRs are used to control the flow on the system within operating reliability limits.

Although some well-known transmission constraints are recurring, new constraints are appearing as electricity flow patterns change as new generation is installed. As a result, the transmission system is being subjected to flows in magnitudes and directions that were not contemplated when it was designed or for which there is minimal operating experience. New flow patterns result in an increasing number of facilities being identified as limits to transfers, and market-based congestion management procedures and TLR procedures are required in areas not previously subject to overloads to maintain the transmission facilities within operating limits.

I conclude with what I see are three challenges ahead in this arena: The first is how to assure that new generation gets built when and where its needed. The second is how to foster greater demand-side participation in the marketplace. The third is adding transmission capacity.

Unlike other commodities, electricity cannot be stored but must be produced in the instant it is consumed. To operate reliably, the system requires redundancy. Redundancy means there is oversupply. Oversupply means that prices are at the marginal cost of production, at peak there is inadequate return of capital investment, and economic failure of some suppliers. We're seeing that now along the Gulf Coast. Competitive markets require elastic supply and demand and scarcity pricing to attract new investment and motivate demand reaction. Scarcity leads to lower reliability (in the sense of less demand served) and, in clearing markets, politically untenable price volatility and perceived transfers of wealth – see California in 2000 and 2001. The oversupply necessary for reliability leads to inadequate return on invested capital and scarcity.

Will it be acceptable for electricity to exhibit the same boom-bust cycle that commodities like oil and natural gas continue to experience? We've seen the recent addition of 100,000 megawatts of gas-fired peaking and baseload generation, which is contributing to relatively low wholesale prices in the regions where it has been built. What will be the incentive under the competitive model for additional peak-serving generation to be built? As capacity shortages develop, prices will inevitably rise, but in the electricity markets, prices can be extremely volatile. Will regulators allow the prices to rise to reflect the shortages? Can we count on the memories of the independent power producers and investment bankers being short enough for them to commit to building the next round of needed generation?

Historically, utilities working through the regional reliability councils and in consultation with their state regulators have determined what the appropriate level of installed capacity would be. Industry participants and the regulators are struggling with that question now. For a time people had optimism that the competitive marketplace would make the resource allocation decisions. It's clear now that a pure commodity model will not suffice. And the good old days of cost-of-service regulation weren't all that good. Back then we had high prices and underinvestment in generation. We'll need a new model for determining who decides how much generation to build.

We still do not have effective mechanisms for the demand side of the equation to participate in the market. That must be part of the solution to the adequacy question. More work needs to be done on the extent to which the demand side will participate in the market and on what mechanisms will be necessary for that to occur. Increasing demand side participation is one way to deal with some of the price volatility that some are concerned about.

Investment in transmission is lagging the investment in generation and the growth in demand. Increasing the transfer capability of the grid is one way to deal with some of the market power issues that are being raised. Even if the decision is to make use of new technology and to de-emphasize building new transmission on new rights-of-way, the questions remain of who has the responsibility to build transmission, and how does it get paid for?