Metric #2: Real-Time System Operations Data Sharing

M.2.1.0 Introduction and Background

A grid that is "smart" engages information technology in the operation of the transmission grid as much as it does in the distribution network. The lifeblood of any smart-grid network is inherently the data and information that drive the applications that, in turn, enable new and improved operational strategies to be deployed. Data collected at any level of the system, from customer metering to distribution, transmission, generation, and market operations, may be pertinent to improving operations at any other level. Thus, sharing data in a timely fashion, approaching real-time, with all those with a need or right to know, is an essential ingredient of a smart grid.

This section defines a metric for increased levels of real-time data sharing. *Real-time* here means operational updates on time scales that may vary from sub-second to a few minutes. For reasons discussed here, the metric focuses on sharing data between parties at the level of bulk transmission grid operations, as opposed to sharing information within a utility, or for engaging demand response or operating distributed generation and storage.

At the distribution-system level, such information includes giving consumers access to consumption data from smart meters so they can use it for demand- and energy-management purposes, for example. Similarly, there may be other information from utility operations that would be relevant to consumers or other third parties acting at the distribution level, such as demand-response aggregators and operators of distributed generation or storage. However, the barriers to this type of information sharing are more procedural and contractual in nature. Other metrics in this report provide indicators of smart grid progress in these areas (e.g., Metrics 5, 6, 7, 9, 11, and 12). Also, within an electricity service provider's operations footprint, it can be reasonably assumed that data are shared, or could be shared, to the extent required to maintain system stability and reliability, within statutory limits separating transmission operations and wholesale-power-marketing activities.[1] That is, the "right to know" within the utility is implicit, and sharing data within the utility is limited primarily by the difficulty and cost of connecting applications to sensor networks and databases.

A *balancing authority* (BA; formerly known as a control area) is defined by the NERC functional model as an entity that regulates system frequency and performs other coordination activities based on field measurements and external data from neighbors and the appropriate reliability coordinator (RC). BAs must maintain the grid's physical integrity and adhere as closely as possible to the agreed-upon schedule for dispatch of generation, imports, and exports. RCs are needed to coordinate the actions of BAs to maintain overall system reliability. The transmission grid has been increasingly utilized to transfer wholesale power long distances, something which neither its physical design nor its management systems were built to support. Two wide-area blackouts in the western interconnection in 1996[2] and the

[1]Federal Energy Regulatory Commission. FERC Order No. 888. *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities.* Accessed November 3, 2008 at http://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp (Last updated May 25, 2006).
[2]North American Electric Reliability Council. 2002. *Review of Selected 1996 Electric System Disturbances in North America*. Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731. Accessed November 3, 2008 at http://www.nerc.com/files/disturb96.pdf (undated webpage).

2003 blackout in the eastern interconnection[3] showed how problems that originated in one area could cause blackouts in other widely dispersed areas, and with no way for the adjacent operators to see the problem coming or limit the damage of the disturbance. To remedy this, there is strong movement to improve wide-area reliability coordination. The metric developed here focuses on the volume of data shared by BAs with RCs. The volume of data shared can indicate the comprehensiveness of their reliability view and analyses.

Beyond simply sharing information upward with RCs, a need for increasing the *situational awareness* of the BAs themselves was identified in the 2003 blackout investigation.[4] BAs already share some SCADA information bilaterally with their neighbors about the status of their grid assets. However, measuring the volume of this data sharing is difficult without significant effort.

If the data shared with the RCs to provide a regional view are exchanged back to the BAs, it would provide another mode of data sharing that could accomplish the same result or improve it. More timely and regionally comprehensive model and data exchange would allow BAs to conduct their analyses with greater accuracy. A metric for this topic should include reverse sharing of data (or state estimates derived from resolving the data with the physical topology of the grid) from the RCs with the BAs, i.e., full two-way flow of such information.

Phasor data, i.e., synchrophasor measurements obtained from phasor measurement units (PMU), contains high-time-resolution (typically 30 samples per second) measurements of voltage and current waveforms, time synchronized and time stamped using the satellite-based global positioning system. Phasor data supplements SCADA data. The current applications that use phasor data do not require the same comprehensive coverage provided by SCADA. Instead, data from a relatively sparse network of PMUs are being used to provide situational awareness and early warning of stability and reliability issues as well as post-event forensic capabilities for wide areas of the grid. To contribute to situational awareness, this information must also be shared.

Ultimately, more comprehensive reliability analysis based on broadly sharing data may lead to increased utilization of wide-area control schemes and remedial action schemes, and allow them to be adjusted dynamically depending on the state of the grid. This is a beginning of the self-healing functions that have long been a key objective of the smart grid at the transmission-grid level.

M.2.2.0 Description of the Metric and Measurable Elements

This section addresses (1) the extent of sharing of SCADA information from BAs upward to RCs and back to the BAs, and (2) the extent of institutionalized data sharing of synchrophasor data among utilities, BAs, and RCs.

(Metric 2.a) Total SCADA points shared per substation (ratio)—the number of SCADA transmission grid measurement points from grid assets that are shared by BAs with RCs, plus the number of SCADA measurement points shared by the RCs with BAs, divided by the number of substations:

[3]U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations.* Accessed November 3, 2008 at http://www.pi.energy.gov/powertaskforce.html (undated webpage).
[4]U.S.-Canada Power System Outage Task Force. 2004.

(Total_Points_BAs→RCs + Total_Points_RCs→BAs) / Total_Substations

- *Total_Points_BAs→RCs*: the number of transmission-grid measurement points (e.g., voltage, power flow, etc.) from grid assets routinely shared by a control area with the RC responsible for supervising its region. The greater the number indicates the more complete a picture of grid status is being shared with the RC. *Measurement point* corresponds to a sensor, not it's time-series output, i.e. each sensor counts as "one" regardless of the frequency of the measurements it records or that are shared. The phrase "from grid assets" is intended to prevent duplicate counts of a single measurement point to which adjoining BAs jointly have access and both forward to the RC.

- *Total_Points_RCs→BAs*: the number of transmission-grid measurement points routinely shared by the RC back to the BAs under its purview. The RC may share a set of data points with each of the BAs; each measurement point shared counts as "one" regardless of how many BAs receive it. Again, this is to prevent counting the measurement point once for each of many Bas that may receive it. This definition presumes that if a measurement point is shared with one BA, it would be available to all of them. By adding the measurement-point data shared in each direction, there is an implicit "perfect score" for a measurement point of exactly two, representing full two-way data sharing. If state estimates based on the data are shared by the RC, instead of raw data, then this should be counted as full two-way data flow.

- *Total_Substations:* The denominator of the metric is defined as the total number of utility substations within the BAs supervised by the RC. This is chosen instead of the number of busses used to model the system, because it is less ambiguous.

The metric can be used at any level of the grid, but should be computed and reported for each interconnection in the U.S. and for the U.S. grid as a whole.

(Metric 2.b) Fraction of transmission-level synchrophasor measurement points shared multilaterally (%) — the fraction shared is the number of phasor measurement points routinely shared via a multilateral institutional arrangement divided by the total number installed in a region of the power grid.

Total_Phasor_Measurment_Points_Shared / Total_Phasor_Measurement_Points

- *Total_Phasor_Measurement_Points:* One count for each measurement from each PMU or equivalent installed on the grid at voltage levels above distribution voltage. Many new grid-sensing, control, and protection devices have PMU capabilities built in; if they are installed on the distribution system, they would not be counted.

- *Total_Phasor_Measurement_Points_Shared:* One count for each measurement from each transmission-level PMU or equivalent that is routinely shared via a multilateral institutional arrangement. This intentionally excludes bilateral arrangements because they are difficult to track, are less likely to persist over time, and may not be comprehensive.

Metric 2.b can be derived for any region of the grid, but will be computed and reported for each interconnection in the U.S. and for the U.S. grid as a whole.

M.2.3.0 Deployment Trends and Projections

A recent survey by Newton-Evans Research[5] indicates there is significant sharing of measurement, analysis, and control data from utility control systems for transmission and distribution (SCADA, energy management systems – EMS, and distribution management systems - DMS) with other grid entities including regional control centers and other utilities. The results of this survey of 30 U.S. investor-owned utilities, 46 public power utilities, 51 U.S. rural electric cooperatives, and 18 Canadian utilities in North America appear in Figure M.2.1, which shows the current and projected integration of EMS/SCADA/ DMS systems to a variety of other control systems. It indicates that currently 28% have linkages with ISO/RTOs and 21% have linkages with regional control systems. By 2010, an additional 4% and 2% expect to have such linkages, respectively. These values capture part of the intent of Metric 2.a, but do not indicate the full extent or comprehensiveness of the data being shared. The survey also indicates that 60% of the control centers in North America have linkages with other utilities, which indicates the extent of bilateral data exchanges.

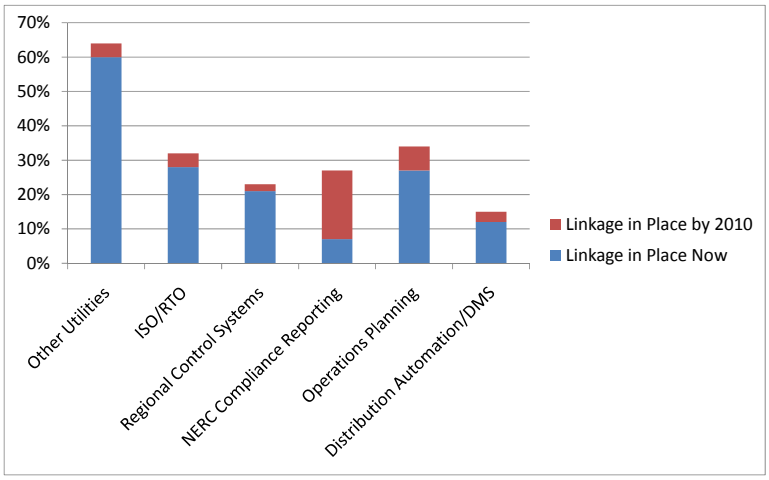

Figure M.2.1. Current/Future Plans for Connecting EMS/SCADA/DMS Systems to Other Data Systems[6]

The data for Metric 2.b was obtained from the participants of the North American SynchroPhasor Initiative (NASPI), a joint DOE-NERC effort to facilitate and expand the implementation of phasor technology for enhancing power system situational awareness and reliability. The results for Metric 2.b are shown in Table M.2.1. The table shows the total number of PMUs installed, the total number shared on a multilateral basis through institutions such as NASPI, and the fraction of transmission-level phasor-measurement points shared multilaterally (Metric 2.b) for each North American interconnection. Only the Eastern Interconnection currently has a multilateral data sharing agreement, which involves 86% of the 104 PMUs. For the entire North American transmission grid, 51% of the installed 175 PMU data points are shared.

[5]Newton-Evans Research Company. 2008. *Market Trends Digest*. Newton-Evans Research Company, Endicott City, Maryland. Accessed November 11, 2008 at: http://www.newton-evans.com/mtdigest/mtd3q08.pdf
[6]Newton-Evans 2008.

Table M.2.1. Fraction of PMU Data Points Shared in the North American Transmission Grid

Interconnection	PMUs Installed	PMUs with Multilateral Data Sharing Agreements	Fraction Shared Multilaterally
Electric Reliability Council of Texas	0	0	(NA)
Eastern Interconnection	104	89	86%
Western Interconnection	61	0	0%
Quebec Interconnection	10	0	0%
Total, North American transmission grid	**175**	**89**	**51%**

The interviews with 21 electricity providers done for this report asked a set of questions that looked at data sharing, primarily within the utility enterprise. The results are shown in Figure M.2.2. Perhaps the most telling response is that 40% of respondents agreed that "new information is flowing across functions and systems."

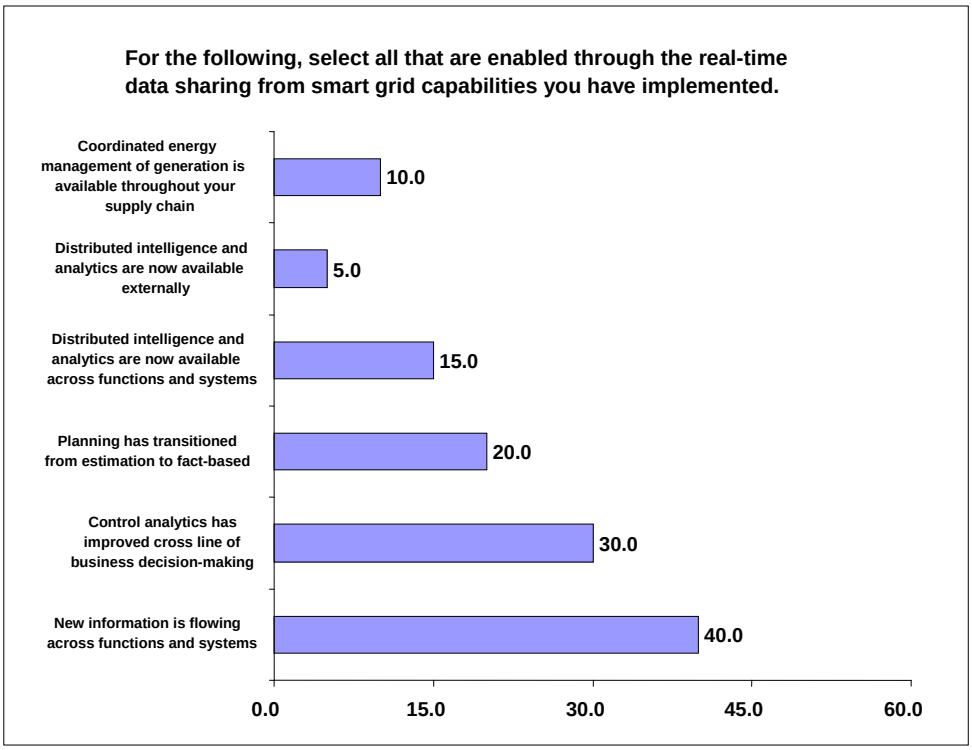

Figure M.2.2. Summary of Interviews Regarding Real-Time Data Sharing

M.2.3.1 Stakeholder Influences

Aspects of the U.S. electrical transmission system are regulated mostly on both a federal level (reliability and interstate commerce) and at the state level (siting, prudency of investment, rate recovery). Input and planning for the transmission infrastructure is conducted, in increasing levels of detail and ultimate authority, by groups of state/regional governments, regional RCs, regional transmission operators or independent system operators (where they exist), and the utilities themselves. The planning and operation of the transmission grid involves the participation of a very large number of stakeholders as well.

Among the stakeholders indentified in Section 1.3 the following have special interest in transmission-level real-time data sharing (Metrics 2.a and 2.b):

- Transmission providers and BAs: The metrics provide a benchmark for transmission providers and BAs sharing information that raises their situational awareness, can increase reliability, and may eventually result in wide-area control schemes that help realize the goal of a self-healing grid.
- Reliability coordinators including NERC: The metrics provide a benchmark of progress toward increasing sharing of data by NERC's constituents. Data sharing helps NERC achieve its reliability goals. The existence of the metrics themselves could serve as motivation toward institutionalizing data-sharing mechanisms (especially for phasor data).
- Products and service providers: Increased sharing of transmission data over wide areas opens up opportunities to develop new analysis applications driven by the data, which in turn may help promote sales and installation of phasor-measurement-capable devices.
- Local, state, and federal energy policy makers; policy advocates: The existence of the metrics helps them focus on and drive the institutionalization of data-sharing mechanisms.

Other stakeholders with less direct interest include:

- Generation and demand wholesale electricity traders/brokers: They benefit from the more reliable electric grid that sharing data enables because market-based dispatch is less often disrupted by operational contingencies.
- Distribution-service providers: They benefit indirectly because the more reliable bulk-power system that data sharing will enable causes less disruption to their distribution systems.
- Electric-service retailers and end users: They benefit from being able to offer and obtain, respectively, more reliable electric service.

M.2.3.2 Regional Influences

The metrics are measured for each interconnection because of the strong regional differences associated with the size and governing institutions for each of the three interconnections. The Electric Reliability Council of Texas (ERCOT) is by far the smallest of the three in terms of population, number of substations, load served, and geographic area. It also has the most unified institutional arrangement, with ERCOT acting as the regional transmission operator and planner, the market operator, and the RC. As such, it has great authority to engage constituent utilities in integrating their transmission data.

The Western Interconnection is nearly as large in extent as the Eastern Interconnection, yet serves a significantly smaller population scattered mostly in widely-separated pockets. It's widely-separated population centers and generation causes it to have special problems with low-frequency oscillations and dynamic stability, issues that led to the 1996 blackouts, and have driven it to be an early adopter of data-sharing arrangements. An interconnection-wide coordination council (the Western Electricity Coordinating Council[7] [WECC]) was created in 2002 with a focus on wide-area issues associated with reliability. Of particular note with respect to Metric 2.b, members of the Western Interconnection were the early pioneers for phasor data collection and sharing in the 1990s (albeit it remains bilateral rather than institutional).

The WECC is now engaged in constructing a fully-detailed operational model of the entire interconnection, so that interconnection-wide state estimation and contingency analysis programs can be performed. This is an example of how data sharing enables increased levels of situational awareness that should result in higher reliability. This development will drive increased data sharing that should result in higher values for Metric 2.a in the future.

The Eastern Interconnection with its large area, dense population, and closer proximity of population centers to generation, has thirteen RCs compared to the Western Interconnection's three. The eastern grid is relatively "stiff" in that it does not exhibit the oscillatory behavior that the West Interconnection does. The 1996 and 2003 blackouts clearly showed that such events can extend beyond even the larger areas of a single RC, yet the Eastern Interconnection does not have an interconnection-wide institution charged with reliability like the WECC that can help drive data sharing. Partly as a result of the 2003 blackout, however, an Eastern Interconnection Phasor Pilot (EIPP) project was established that has pioneered phasor data sharing with the notion of phasor data concentrators that collect and archive all of it. The EIPP is the precursor of NASPI, which is attempting to formally institutionalize data sharing, among its other objectives.

M.2.4.0 Challenges

Technical, business, and policy challenges all complicate the use "real-time data exchange" as a metric of smart grid evolution.

M.2.4.1 Technical Challenges

The principal technical challenges involved with data sharing at the transmission level involve the level of effort to identify, configure, and maintain the data to be exchanged between parties. Standard protocols exist for inter-control center site data exchange and phasor data exchange. Most suppliers of control center systems support these standards; however, complete, unambiguous interoperability requires significant processing and testing. Besides the data exchange protocols, common naming conventions and unambiguous identity services would make integration and maintenance easier. Software interfaces that support publishing, and interrogation services that are consistent with cyber security and information privacy policies (see business and policy challenges below) would reduce the manual labor involved to support data sharing.

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[7]Western Electricity Coordinating Council. 2008. *Western Electricity Coordinating Council Mission and 2007 Goals*. Accessed November 3, 2008 at http://www.wecc.biz/documents/library/publications/Mission%20Statement%20-%202007%20Goals.pdf (undated webpage).

Situational awareness and system operations applications, such as state estimation, also require the sharing of system modeling data. Power system models are complex and continually evolve as parts of the system are taken out of service or new construction is added. Ownership and responsibility rights are also continually changing and require periodic updates. Data sharing initiatives can be put on hold or discarded because the parties involved are not willing to support and exchange the requisite system models. Agreement on technical approaches and services can help reduce model maintenance and the burden of keeping neighbor model consistent; however, the problems are complex to explain, and therefore, often underappreciated by the organizations involved.

M.2.4.2 Business and Financial Challenges

There are procedural, business and privacy issues that hinder sharing of data and information collected by a utility with peers and higher-level grid RCs. This applies to SCADA, phasor measurements, and derived data from application programs. Certain circumstances may require sharing of information with non-grid entities such as emergency-response centers or state and federal government agencies charged with public safety, homeland security, or national defense. Formalized mechanisms for data exchange would simplify data collection for these metrics.

The inhibitions to sharing such data include:

- competitive intelligence – the value of operational information could be used in corporate takeovers, service-territory takeovers, change to municipal service by cities or utility districts ("municipalization"), or competition to serve areas of growth that do not currently have service;

- market intelligence – merchant generators, power marketers, and aggregators may be able to glean information that enhances their bidding strategies in deregulated wholesale markets, and regulated utilities may want to inhibit competitors from serving load in their service area;

- second guessing and prudency reviews – from peers, competitors, federal and state governments and regulators, and consumers, about operational decisions;

- financial penalties – associated with outages or unsafe operating conditions, in the form of fines from reliability-monitoring entities for operating outside guidelines or specifications, lawsuits from customers for damages from outages, and reduced incentive payments from state utility regulators;

- data security – concern that shared information may not be kept secure and therefore could highlight physical or control-system vulnerabilities that could be exploited to the detriment of national security.

These inhibitions are particularly significant when operational data must be shared among peers, particularly utilities and BAs.

M.2.5.0 Metric Recommendations

The results for Metric 2.a have not yet been collected. The intention is to gather this information from key industry stakeholders, such as the Data Exchange Working Group or the Reliability Coordinator

Working Group, both under the NERC Operating Committee. The intent is to create a table that shows the total measurement points shared by BAs with the RCs, by RCs with the BAs, the total number of utility-owned substations in each interconnection, and the Number of shared SCADA points per substation node (Metric 2.a). These are broken down within each interconnection by RC, and aggregated to the U.S. power grid. This should be done as soon as possible so that a baseline is established for future versions of this report.

Bilateral data exchanges are not formally recognized in this metric, as defined, but could be incorporated in this framework if desired or needed. For example, if the RC did not deliver data from measurement points to BAs, but instead the BAs in a region agreed to universally share a set of measurement points with each other through another arrangement, this would accomplish the same end, and each point shared should be counted as "one."

Since metrics have inherently subjective qualities, interviews with individuals within utilities could provide a more accurate view of the situation. Future interviews conducted for this report should develop questions that more directly align with the BA/RC data sharing metrics expressed here.

An analogous metric might be developed for data exchange with customers. One such metric could be constructed around whether customers have real-time access to their meter data. For metrics focused on the issue of whether sufficient information is exchanged with customers so they can participate, it can be argued that most customers would not be able to respond to such questions in legitimate fashion. Perhaps technology vendors and aggregators could represent customers in this regard, with a more solid technical basis. It should be noted that expectations for data exchange with customers will tend to grow over time. An example of this is the emerging desire to provide ancillary services with customer demand response, which at present requires intensive and timely data exchange on 4-second intervals.

For Metric 2.a and 2.b, it should be recognized that data exchange at the bulk grid/transmission level is only a means to an end. The end result is situational awareness leading to increased reliability and eventually a self-healing grid. Exchanging data does not accomplish anything, in and of itself. If metrics could be developed that better capture that the data is being *used,* which applications it was being used *for*, what the *geographic/topological scale* of the analyses are, these would better capture the intent of data sharing metrics for the transmission grid. Similarly, we have made the simplifying assumption that exchange up to the RC and back to the BAs has the most merit as an indicator of progress. But, this avoids grappling with the issue of whether the RC is the right scale for situational awareness, or whether a broader scope of awareness needs to exist.