Determining Distribution Grid State Coverage Computationally

November 2019

JD Taft
A Reiman
C Neubauer

PNNL-29338

PACIFIC NORTHWEST NATIONAL LABORATORY
operated by
BATTELLE
for the
UNITED STATES DEPARTMENT OF ENERGY
under Contract DE-AC05-76RL01830

Printed in the United States of America

Available to DOE and DOE contractors from the
Office of Scientific and Technical Information,
P.O. Box 62, Oak Ridge, TN 37831-0062;
ph: (865) 576-8401
fax: (865) 576-5728
email: reports@adonis.osti.gov

Available to the public from the National Technical Information Service
5301 Shawnee Rd., Alexandria, VA 22312
ph: (800) 553-NTIS (6847)
email: orders@ntis.gov <http://www.ntis.gov/about/form.aspx>
Online ordering: http://www.ntis.gov

Determining Distribution Grid State Coverage Computationally

JD Taft[1]
C Neubauer[1]
A Reiman[1]

November 2019

[1] Pacific Northwest National Laboratory.

Contents

1.0 Introduction 1
2.0 Problem Definition 1
3.0 Visibility, Transportability, and Observability Definitions 2
4.0 Determining Observability in Distribution Grids 4
4.1 Numerical Methods 4
4.2 Topological Methods 5
5.0 Calculating Indices and Identifying Islands of Observability 5
5.1 Constructing the Symbolic Jacobian 5
5.2 Identifying Observable Islands 6
5.3 Calculating Indices 6
5.3.1 Example Results 6
6.0 Summary Comments and Next Steps 9

Figures

Figure 1. Basic Definitions and Their Relationships 3
Figure 2. Visibility/Observability Evaluation Process 3
Figure 3. Example 1 Topology and Observable Islands 7
Figure 4. Example 2 Topology and Observable Islands 8

1.0 Introduction

The FY 2016 GMLC Sensing and Measurement Strategy project (1.2.5) included a task to develop a definition of extended grid state. This definition is an information-level taxonomy that defines the full range of information needed to operate a power system. This include traditional electric or power state (voltage, currents, power flows, and phase angles) but also asset and environmental conditions. The full extended state definition document is available online.[1] The purpose of this definition is to support the design of modernized grids by providing a comprehensive view of the full range of information that constitutes the operating status of the grid. It is not a list of measurements and is not a data specification.

The purpose of the definition is to inform architectural and design aspects of modernized grid sensing and measurement, data architecture, and interoperability standards specification and standards usage by providing a comprehensive view of the full range of information that constitutes the operating status of the grid. It is intended to be compatible with and possibly to extend existing models such as the IEC Common Information Model. This definition is not a list of electricity measurements or data elements (although in some cases a state element maps directly to a measurement). It is an abstract information taxonomy for understanding electric grid operation.

Because it is abstract, relating the definition to actual grid sensing and measurement aids in two ways:

- It illustrates how to apply the Extended Grid State definition
- It provides validation of the Extended Grid State definition by showing how grid sensing can yield abstract grid state elements

The Extended Grid State Definition Document defines a grid in terms of operational information but does not address what measurements must be made to support all or any subset of the Extended Grid State. The work reported on in this document addresses the gap between measurement and Extended Grid State and thereby provides a level of validation for the Extended Grid State concept and definition

2.0 Problem Definition

For this work, we focus initially on the subset of Extended Grid State that poses one of the more difficult challenges in relating sensing and measurement to grid state: determining power state from a set of grid physical measurements. This problem is significant because it is not practical to make a massive number of measurements, so a key question arises:

How much sensor data is actually necessary to operate a power grid?

To answer this question, we will need to define several characteristics of the grid that allow us to evaluate how well we can determine grid state elements, given a set of measurements (type and location on the grid), given a means to move sensed data to points of usage, and given a system model of some degree of accuracy (but less than perfect).

The specific problem this work addresses is:

[1] JD Taft, E Stewart, and Z Li, Extended Grid State Definition Document, PNNL-SA-141027, February 20-19, available online: https://gridarchitecture.pnnl.gov/media/white-papers/Extended_Grid_State_Definition_v3.3_GMLCFormat_final.pdf

How can we evaluate the degree to which a given set of measurements on a grid with a given communications network enables us to determine the power state portion of extended grid state?

The more general case involves the complete determination of full extended grid state from a set of measurements (which go beyond electric parameters such as voltage and current used for power state).

3.0 Visibility, Transportability, and Observability Definitions

We begin with a set of structured definitions. As pointed out in the Grid Architecture work, the definitions of grid characteristics are not just set of standalone items; they also have relationships to each other and therefore fit into a structure. Understanding the structure as well as the element definitions provides a powerful means to reason about the grid.[2]

Grid visibility is the capability to obtain usable measurements on grid parameters. This involves two functions:

- sensing and metrology at points on the grid
- moving the sensed data to points of use (transport)

The need to move the sensed data from remote grid locations to point of use given the imperfection of data communications leads to another definition:

Transportability is the ability to transfer sensed grid data from sensing points to points of use. This is essentially about the capabilities of the communication systems used for grid data.

Grid observability is the ability to combined sensed data with grid models and various types of computations (analytics, estimators, forecasters) to generate actionable grid state information to be used by decision and control processes.

Figure 1 shows the relationships among these characteristics. Visibility is a compound of a set of measurements and the transport of these measurements. Observability introduces the concept of computation to build upon visibility by determining elements of grid state that may not have been directly sensed and may require processing to extract them from “raw” sensor data.

[2] GMI Grid Architecture Core Team, Grid Characteristics: Using Definitions and Definition Structure for Decision-Making, PNNL-SA-141678, February 2019, available online: https://gridarchitecture.pnnl.gov/media/methods/Grid_Characteristics_Definitions_and_Structure.pdf

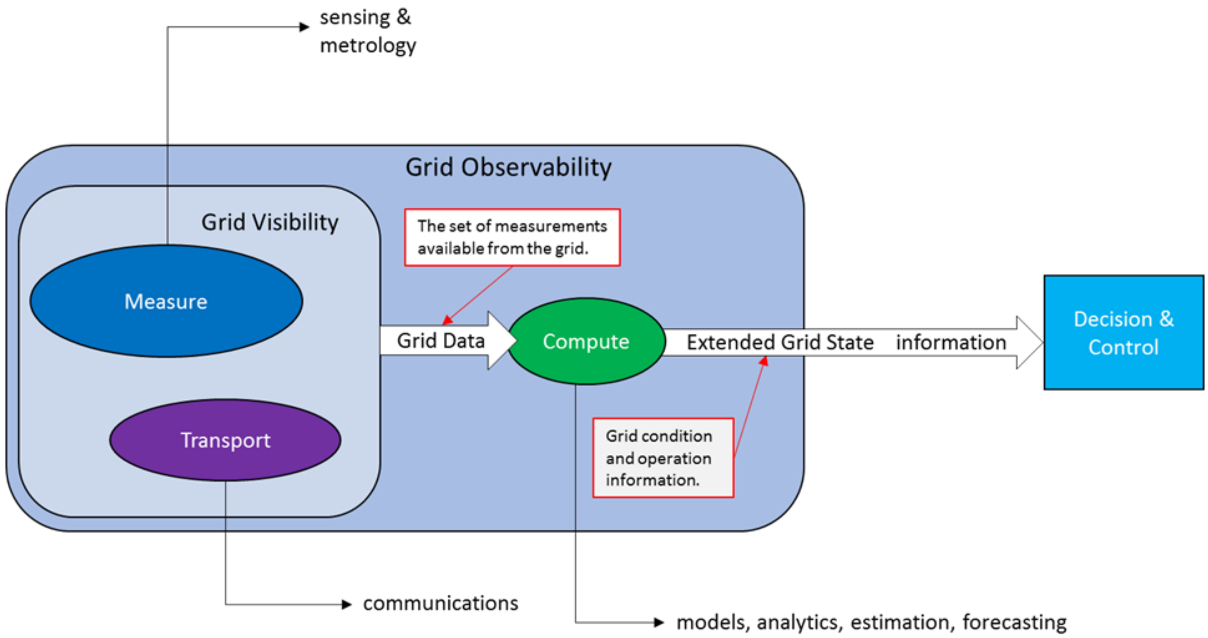

Figure 1. Basic Definitions and Their Relationships

Given these definitions, we may define a process that evaluates how well a given set of data from a specific grid with a particular communication network enables us to determine the portion of grid state on which we are focused (e.g. power state). Along the way, we must deal with some elements of uncertainty:

- Deficiencies in the system models used in the process of computing grid state elements from grid measurements
- Characterization of data transport effectiveness without detailed network simulation

Figure 2 shows a high-level view of the evaluation process.

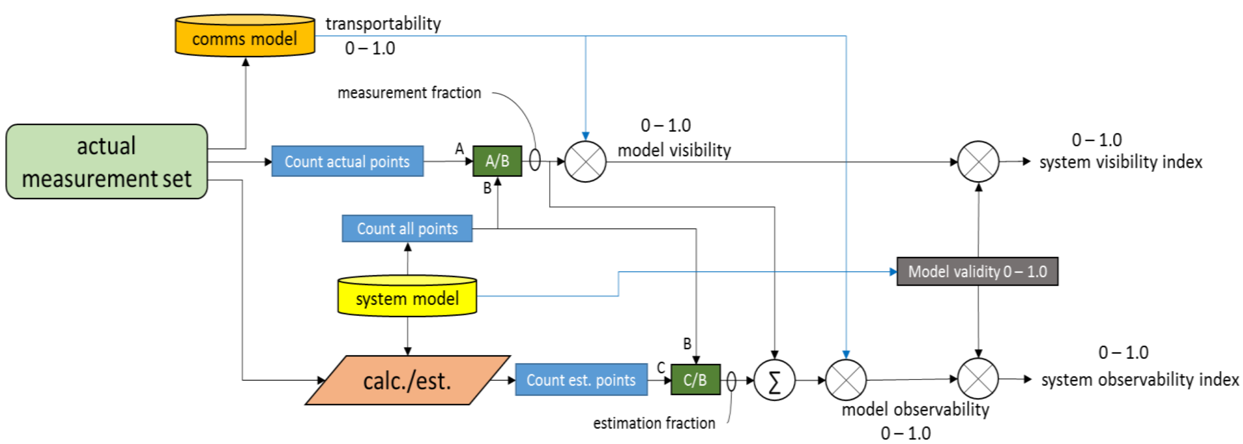

Figure 2. Visibility/Observability Evaluation Process

Starting with a grid model, a set of sensors and their locations, and some information about the communication network, the process computes two indices (scores in the range of 0.0 to 1.0).

One is the system visibility index (measures how much direct visibility the sensors provide); the other is system observability index (measures how much observability the sensors support). In the process, some intermediate variables must be determined. One is the measurement fraction (the ratio of actual measurements to total possible non-redundant measurements). The other is the estimation fraction (the ratio of state elements that can be estimated to the total number of state elements that define the grid state but have not been directly measured). We introduce transportability as an overall index that modulates the two fractions to produce model visibility and model observability (indices that assume the system model is perfect). Finally, we use a model validity index as a modulator on the model indices to produce the system visibility and observability indices. This last step accounts in a general way for the fact that system models can have inaccuracies without needing to specifically detail those inaccuracies.

The model validity index value comes from the electric utility engineering staff. For transmission systems, the models tend to be quite good. For distribution, model accuracy typically falls in the 60-80% range. The distribution engineers can usually characterize this well without enumerating specific inaccuracies, so this index serves to account approximately for overall system model deficiencies. This is not an exact solution, but since we are computing general (systemic) scores, it does not have to be precisely granular.

Transportability is handled in a similar fashion at this level: a transportability index is used to modulate measurement fraction and estimation fraction to generally account for communication limitations without enumerating specific deficiencies. Determination of the transportability index is somewhat more elaborate than the model validity index. It is based on a formula that takes into account network path redundancy as well as performance parameters (channel throughput, latency, and packet loss). This information is typically known to the utility engineers responsible for operational communications.

4.0 Determining Observability in Distribution Grids

In the literature, there are two categories of methods for determining observability as required for state estimation:

- Numerical methods[3]: calculating the rank of the Jacobian of the measurement function.
- Topological methods[4,5]: using system structure to determine states that can be calculated using a given set of measurements (e.g., spanning tree methods and symbolic Jacobian methods).

4.1 Numerical Methods

A measurement function expresses the set of measurements in terms of the set of system states (typically the complex node voltages or branch currents). If the measurement function is linearized, its Jacobian will be constant and the rank of the Jacobian will give insight into the degree of observability of the system. A full-rank Jacobian corresponds to an observable system. The relationship between complex power flow and voltage angles must be considered carefully.

---

[3] A. Abur and A. G. Exposito, *Power System State Estimation: Theory and Implementation*. Marcel Dekker, Inc., 2004.
[4] G. R. Krumpholz, K. A. Clements, and P. W. Davis, "Power System Observability: A Practical Algorithm Using Network Topology," IEEE Transactions on Power Apparatus and Systems, vol. PAS-99, no. 4, pp. 1534-1542, 1980.
[5] V. H. Quintana, A. Simoes-Costa, and A. Mandel, "Power System Topological Observability Using a Direct Graph-Theoretic Approach," IEEE Transactions on Power Apparatus and Systems, vol. PAS-101, no. 3, pp. 617-626, 1982.

4.2 Topological Methods

Algorithms have been developed, especially for transmission systems, to map measurements onto a spanning tree of the system topology. Making some assumptions about the measurement set (e.g., that flows and injections are measured in complex pairs) or about the model (e.g., that real and reactive flows are decoupled due to high line X-R ratios – this is **not** a reasonable assumption in distribution systems), the existence of such a spanning tree has been shown to guarantee topological observability.

Alternatively, topological methods can operate on the structure of the measurement function Jacobian, even if the measurement function is not linearized. A symbolic Jacobian[6] is a binary matrix that shows which buses are related to each measurement. Symbolic algebraic analysis can be used to determine whether there are sufficient equations (corresponding to measurements) to solve for the number of unknown system states (e.g., node voltages).

Observable islands are topological regions of a system where, with at least one measured bus voltage, all other bus voltages can be determined. With some bookkeeping, after observable islands have been identified, one can calculate those node voltages, node injections, and branch flows.

The symbolic Jacobian method can be readily extended to unbalanced distribution systems so long as (a) complex values are measured and (b) for each single-phase measurement, all other existing phases of the same bus (voltage) or branch (current or power) are also measured. In this case, the symbolic Jacobian, which still maps measurements to buses, even if some or all buses have multiple phases.

5.0 Calculating Indices and Identifying Islands of Observability

To calculate the system observability and visibility indices, we first use the symbolic Jacobian method extended for distribution systems (as described in the previous section) to identify observable islands. Observable islands consist of voltages that can be estimated, which in turn determine the possible measurements can be estimated. Sensor types and locations as well as the system connectivity are required for this algorithm. These inputs may be provided by an advanced distribution management system (ADMS) platform or by a combination of utility planning and operations databases. This algorithm has been implemented as an application for GridAPPS-D[7], a standards-based ADMS application development platform.

5.1 Constructing the Symbolic Jacobian

The symbolic Jacobian is a binary matrix that maps measurements to their adjacent buses; in mathematical terms, it describes the set of bus voltages that would be required to calculate the value of the measurement. To construct the symbolic Jacobian, two sets of data are required:

1. System connectivity: This input can come from a network admittance matrix or from a network connectivity (e.g., GIS) database. If a multi-phase admittance matrix is used, the bus-to-bus

[6] I. W. Slutsker and J. M. Scudder, "Network Observability Analysis through Measurement Jacobian Matrix Reduction," IEEE Transactions on Power Systems, vol. 2, no. 2, pp. 331-336, 1987.
[7] R. B. Melton *et al*., "Leveraging Standards to Create an Open Platform for the Development of Advanced Distribution Applications," in *IEEE Access*, vol. 6, pp. 37361-37370, 2018.

connectivity must be extracted. The algorithm can be performed using connectivity alone; however, to actually estimate states, the admittance parameter(s) of each connection are required.

2. Sensor types and locations: Sensor locations may be described in terms of measured equipment or in terms of measured nodes and/or branches. Sufficient information must be provided to map measurements onto specific system states.

5.2 Identifying Observable Islands

Once the symbolic Jacobian has been constructed, symbolic algebraic substitution is used to determine which unknown voltages can be calculated given known voltages. The algorithm consists of the following steps:

1. *Group buses into candidate observable islands*
    a. *Substitution using flow measurement equations:* if the voltage at one endpoint of a flow measurement is known, the voltage at the other endpoint can be estimated.
    b. *Substitution using single-adjacent-bus injection measurements:* current or power injected into a bus with only adjacent bus (or one adjacent bus with unknown flow) can be treated as flowing from the injection bus to the adjacent bus.
    c. *Simplification using multiple-adjacent-bus injections measurements:* sets of adjacent bus injections are analyzed for solvable subsystems consisting of the same number of measurement equations as unknown bus voltages.
2. *Check voltage measurements to identify observable islands:* a candidate observable island with at least one voltage measurement is an observable island.

5.3 Calculating Indices

Once the observable islands have been identified, observable measurements can be identified:

- Point (bus voltage) measurements are observable if the associated bus is a member of any observable island.
- Flow (branch current or power) measurements are observable if the buses on both ends of the branch are each members of any observable island.

Injection (load or distributed generator power or current) measurements are observable if the injection bus and all topologically adjacent buses are members of any observable island.

After identifying the set of observable measurements, the measurement fraction and the estimation fraction along with the system visibility and observability indices can be determined arithmetically per Figure 2.

5.3.1 Example Results

Below are two example cases showing how small increases in Visibility can result in large increases in Observability. The first example provides a base case. In the second example, measurements are added to show the change in Observability.

Both examples assume a Transportability of 100% (i.e., no losses in transmission of data). These examples also have a Model Validity of 93%.

5.3.1.1 Example 1

In the Example 1 topology, there are three Observable Islands clustered around the sensors. The center and some extremities of the model are not part of any observable island, as there are no nearby sensors.

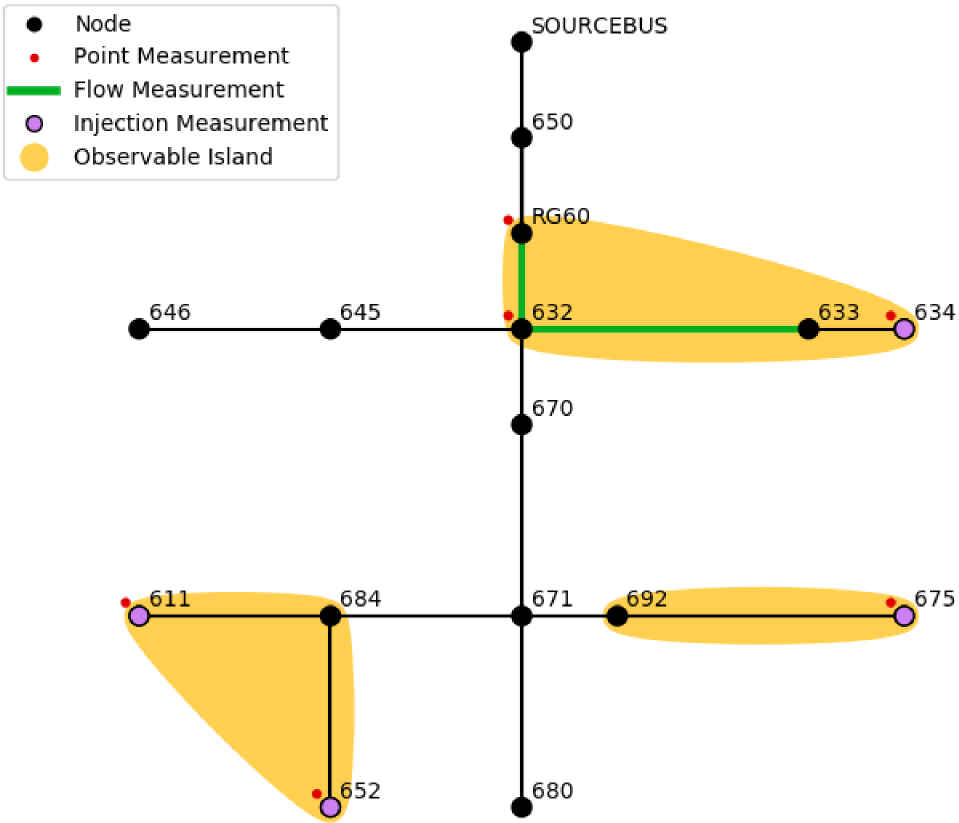

Figure 3. Example 1 Topology and Observable Islands

In the first example, the Measurement Fraction is 0.255, meaning that approximately 25% of the nodes in the model have attached sensors. This results in a Model Visibility Index of 0.255 because we assume no losses in data transport for this example. With a Model Validity of 0.93, the System Visibility Index is 0.237.

For the Observability Index, the Estimation Fraction is 0.17. This is added to the existing Measurement Fraction and multiplied by the Transportability index, resulting in a Model Observability Index of 0.4255. We then multiply it by the Model Validity of 0.93, producing a final System Observability Index of 0.3957.

5.3.1.2 Example 2

In the second example, we added four measurements to the model, representing new sensors.

There is one new point measurement and one new injection measurement, each at Bus 646; there are two flow measurements, one from Bus 632 to Bus 670, and one from Bus 670 to Bus 671.

These new measurements result in a new Observable Island at Buses 645 and 646. The largest Observable Island expands to include Bus 670 and Bus 671. As expected, a few nodes at the extremities of the system are still unobservable.

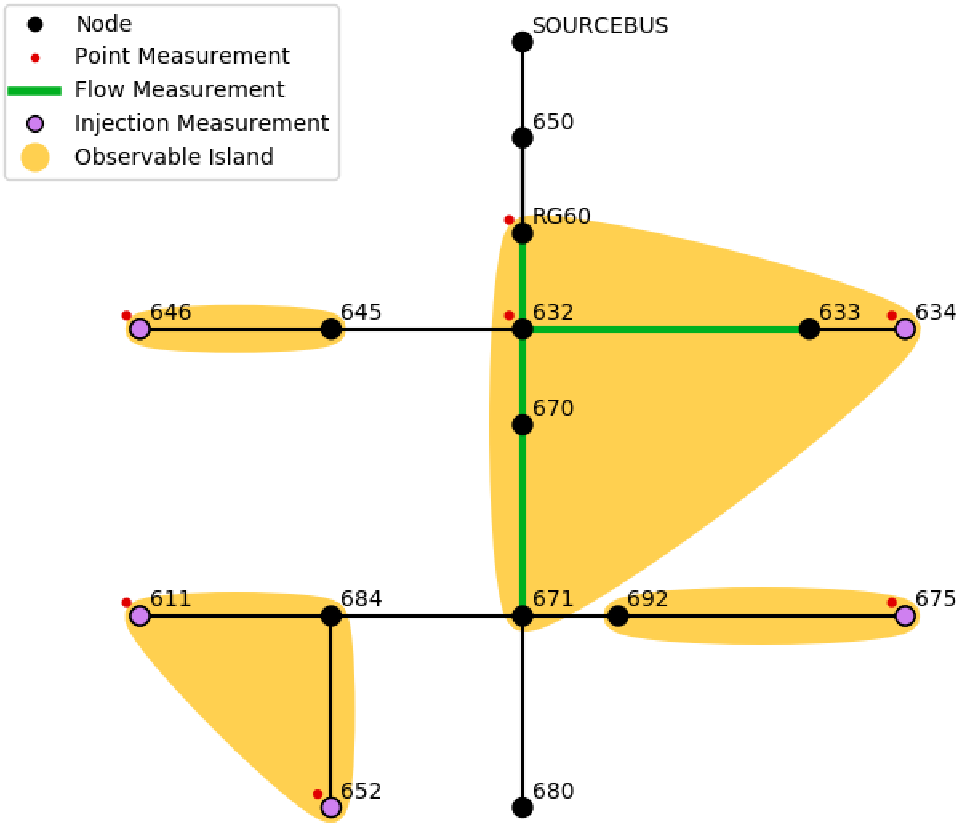

Figure 4. Example 2 Topology and Observable Islands

In the second example, the Measurement Fraction has increased slightly to 0.34. Again, Model Visibility Index is 0.34 because we assume no losses in data transport in this example. A Model Validity of 0.93 results in a System Visibility Index of 0.3166.

The Estimation Fraction is 0.4255. Factoring in the Measurement Fraction and the Transportability gives us a Model Observability Index of 0.7660. The Model Validity of 0.93 results in a System Observability Index of 0.7123.

Finally, the System Visibility Index increased by 0.0851, about 33%. The System Observability Index increased by 0.3404, or 80%. As seen here, small changes in instrumentation (and therefore instrumentation cost) can result in large changes in Observability, or coverage of the Extended Grid State.

6.0 Summary Comments and Next Steps

The most difficult aspect of this project was the development of a means to determine distribution system observability from a system model and a sensor allocation. Other aspects of the index computation process are not as difficult but still make use of the system model from GridApps-D. While the primary intent was to develop a scoring system so that we could determine how well sensing mapped into Extended Grid State elements, a bonus byproduct is the visualization of islands of observability. Using this software tool, we can explore and connect sensing to Extended Grid State as a means of understanding how well the Extended Grid State approach serves its purpose to inform architectural and design aspects of modernized grid sensing and measurement, data architecture, and interoperability standards specification. This is the validation aspect of the software.

The capability to evaluate Observability also forms the basis for a tool for sensor allocation and optimization. Here optimization means either maximizing observability for a given sensor set cost, or minimizing sensor cost for a given observability.

The logical next steps for this software are:

1. Extend the approach to the rest of the Extended Grid State definition.
2. Integrate graph theory methods to calculate the transportability index from a combination of network parametric values (latency etc.) and *network structure*.
3. Build a set of sensor models to be used in automatic allocation (line sensors, faulted current indicators, meters used as sensors, etc.) with sensor capabilities and adjustable installed costs.
4. Provide user and system interfaces to allow interactive sensor allocation, and auto-ingestion of system (grid) and communication models.
5. Implement automated sensor allocation strategies, using the sensor models from above.
6. Integrate an optimization engine to automatically allocate sensors in accordance with either of the optimization objectives listed above, including constraints such as focus on a subset of a grid for particular applications and use of existing sensors as part of the sensor mix.

This tool has much potential as either an application or a service of GridApps-D and so integration of this software tool with GridApps-D should continue beyond simply accessing system models.

When fully developed, the combination of the Extended Grid State Definition and this software tool will address a major goal of the original Sensing and Measurement Strategy project: to enable electric distribution utilities to develop observability strategies and sensor network designs for grid modernization in the presence of fast dynamics and complex operations well beyond what was envisioned for the 20th Century grid.

GRID MODERNIZATION LABORATORY CONSORTIUM
U.S. Department of Energy

902 Battelle Boulevard
P.O. Box 999
Richland, WA 99352
1-888-375-PNNL (7665)

http://gridmodernization.labworks.org/