Report on Real-time Grid Analysis Pilots

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Abstract— **In August, 2010, Milsoft began its first pilot study of real-time grid analysis at Owen Electric in Kentucky. In this pilot, the IT requirements of the server platform necessary to acquire AMR data and SCADA in real-time was tested and the use of load allocation/load flow converted to perform automatically in real-time was investigated.**

While this was a simple circuit with 60 meters total, the results were successful in proving that real-time distribution analysis is possible. The accuracy of results is still under study; however, the ability to perform these studies automatically in real-time was proven.

Milsoft will attempt to expand this study, as well as begin additional pilots at South Plains Electric in Texas and Minnesota Valley Electric Cooperative (MVEC) in Minnesota, prior to the 2011 conference. This paper will explain the methods used and report on progress.

Additional results available at the time of the 2011 conference will be included in the presentation.

Index Terms— **Distribution Analysis, Distribution Automation, Distribution State Estimation, Load Flow Analysis, Real-Time Distribution Feeder Analysis, Real-time Grid Analysis, Smart Grid, Active Grid Management**

I. INTRODUCTION

In the paper "Real Time Distribution Analysis for Electric Utilities" [1] presented at the 2008 Rural Electric Power Conference, we defined real-time distribution or grid analysis, addressed the reasons for doing real-time analysis and described the reasons why it is now possible. We also outlined our plans to do pilot projects for the purpose of testing and proving our methods. In this paper we will report on our progress with these pilots.

While the progress we can document at the time of writing this paper is limited to the first pilot (as of November, 2010), we expect that we will have started at least one additional pilot as well as expanded the first by conference time (April, 2011) and will expand our presentation to include additional results at that time.

II. DEFINITIONS

- **Fast data**: SCADA, AMR and AMI points that can be read and accessed within five seconds of event time.
- **Slow data**: AMR and AMI points that can be read and accessed but not within five seconds of event time.
- **Bellwether meter**: AMR or AMI points that can be read and accessed in Fast Data time and correlated with Fast Data time SCADA readings.

III. FIRST PILOT – OWEN ELECTRIC

Our first pilot feeder is a small, lightly loaded feeder from the Owen Electric system in Kentucky. With 60 meters, this feeder allowed testing and proving of two very important assumptions:

1) We could do the necessary data collection of SCADA and AMR on a platform that allowed us to then:
2) Run automated (every hour) load allocation/load flow studies.

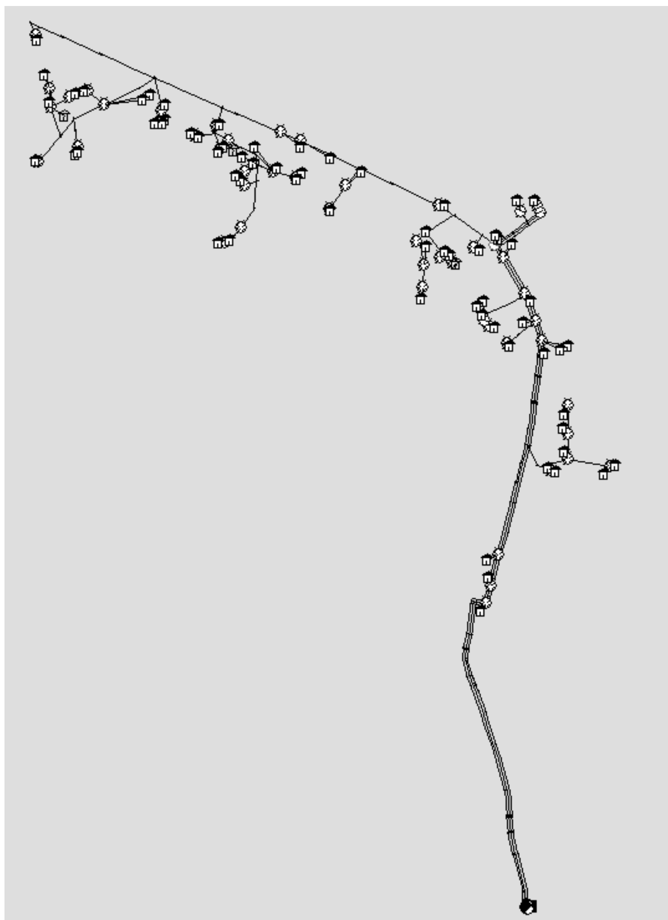

Figure 1- First Pilot Feeder (Owen Kentucky)

While we did not specify that the first pilot feeder should be lightly loaded, the fact that our first feeder had very little load allowed us to discover a very important issue. In the initial test

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test period, SCADA was reporting instantaneous voltage while AMR was reporting a 60 minute average voltage. This inconsistency led to a significant lack of correlation between SCADA voltage and AMR voltage on a meter with no load on a feeder phase with very low current. We assumed that we should see a very close correlation in these voltages since with no load, there should be very insignificant voltage drop between the SCADA point and meter. The fact that there was no correlation at all led us first to suspect the accuracy of AMR voltage readings, but in the process of asking the utility to install a recording voltage meter to test the AMR meter reading, we discovered this inconsistency in voltage reading intervals. It was then obvious that we must eliminate the interval difference before continuing. At the time of writing, we are in the process of trying to obtain five minute average voltage readings on both SCADA and AMR.

In addition to having only 60 meters and very low current loading, this feeder also met our simplicity specification by:

- Having only single phase residential meters:
  - It is assumed, and will be tested in subsequent pilots, that large power and commercial meters of some yet to be determined size will require fast data metering of kW.
- Having no regulation downline from SCADA point:
  - It is assumed, and will be tested in subsequent pilots, that fast data voltage readings will be required immediately downline from each phase of regulator banks.
- Having no capacitor banks:
  - It is assumed, and will be tested in subsequent pilots, that fast data metering will be required downline from switched cap banks to indicate their off/on status.

IV. REAL-TIME GRID ANALYSIS

Real-time grid analysis, as defined for our pilot studies, is the automatic and continuous execution of a least one load flow analysis no less than each hour, or 24 times each day, on each feeder. This process can be broken down into the following continuously repeated steps and procedures:

- Collect SCADA and AMR/AMI data as it becomes available;
- Maintain an accurate, detailed circuit database synchronized with the distribution system;
- Automatically set the necessary values for load allocation control points and customer meter load distribution data fields;
- Implement the correct load flow/load allocation run at the correct time using the appropriate SCADA and AMR data;
- Calculate voltage and current flow values close enough to actual that they can be used to make system engineering and operating decisions
- Store, report and display results as required for engineering and operating the system.

V. COLLECT SCADA AND AMR DATA

Collection, storage and accessing 96 SCADA readings of amps, power factor and voltage per phase, per day, and 24 kW and voltage readings for each AMR meter per day, is a vital requirement for real-time analysis. In our pilot studies, a significant part of what needs to be tested and proven is related to the computer server platform requirements and to complete this automatically and quickly enough to make real-time analysis useful for utility engineering and operations.

Our system interfaces with both SCADA and AMR using MultiSpeak® which is one of the factors that make real-time analysis possible. The ability that this integration standard provides to collect data from other vendor systems is vital to our goal of being data collection vendor neutral. Without MultiSpeak, it would be necessary for us, the analysis vendor, to partner and interface with one SCADA vendor and one AMR vendor. Using MultiSpeak, we can insure that we are system collection vendor neutral. The only requirement is that all other vendors are MultiSpeak compliant.

The preliminary work that we have completed in establishing additional pilots has exposed the problem that not all SCADA and AMR vendors provide the same data. It is expected that this is only a temporary limitation. All the vendors we are working with indicate their eagerness to work with us to accomplish real-time analysis and have shown their willingness to make necessary changes. It is too early in our discovery process to specify exactly what will be necessary, but we will work with each vendor to utilize the data they now have. This will allow us to test our assumptions and clarify what is required.

All data is collected into SQL tables. All data may be viewed and edited from standard SQL software systems. An important goal of our development is that all gathered and calculated data is stored in an open architecture system such as SQL.

The first pilot at Owen did not include a MDM (Meter Data Management) system and therefore had no error pre-processing and no state estimation of meter loads. The plan is to acquire AMR data from MDM systems in at least one of our subsequent pilots. It is expected that MDM error processing and meter load state estimation will be very useful and beneficial for the improvement of load flow result accuracy.

As we expand to more and larger pilot feeders we will expose, and hopefully solve, issues with database size and speed. These issues, and others in the computer server platform, are very important to the success of real-time analysis and will be tested as we advance the pilots.

VI. DETAILED CIRCUIT MODEL

Real-time grid analysis is dependent on a detailed and accurate distribution circuit model.

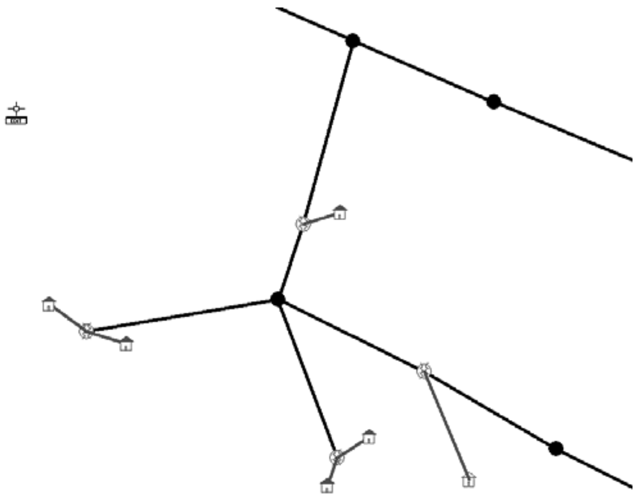

Figure 2-. Detailed Circuit Model

Figure 2 shows a close-up view of our Owen pilot feeder. Note that in addition to all primary line, this model includes each distribution transformer and each customer meter. Up to this point in the analysis, we believe this to be the minimum model required to meet required accuracy levels.

We are now validating and correcting the circuit model for our next set of pilots. The next set of feeder pilots will be typical in the number of customers and loading, as well as include secondary line, large power meters, regulators and capacitor banks. Pilots with distributed generation, such as diesel gen-sets, may also be included in the investigation which will add another degree of complexity since these units may shed all customer load or even operate in parallel with the utility system to export power to the grid. The setup for this in the engineering model, together with capturing real-time information for the generator, is expected to be a significant challenge.

As thoroughly reviewed in last year's paper on the detailed nature of modeling requirements for secondary services [2], model settings and/or equipment attributes are needed to not only completely, but also accurately represent the electrical system. The knowledge necessary to determine what settings and values may affect power flow results is a learning curve for utility engineers that have historically worked with systems at primary voltage levels.

MVEC and South Plains are using GIS Mapping systems to extract engineering models for studies and these are also used for the real-time load allocations and power flows. Seldom are these extracts 100% error free when investigated in the engineering software, as was the case with these. Yet, from a GIS level, these systems appeared almost perfect and met the needs for mapping and asset management purposes, but not for power flow purposes.

Historically, the secondary service conductor sizes were of less interest at MVEC; therefore, time was spent assigning a best-guess secondary conductor size to each unique transformer size. With the South Plains model, secondary conductor sizes were included in the GIS. However, the difficulty with this model came with the transformer winding assignments, as they were all set up as Y-Y grounded. Simple global edits were accomplished in the EA model by referencing the rate codes per meter/customer obtained from CIS, then using a reference sheet that listed transformer winding type and phase per rate class.

Just as important as the conductor and transformer assignments throughout the models, the attributes assigned to each piece of equipment in the equipment database were reviewed and corrected. Some of the attributes, such as percent impedance and X/R for center-tapped transformers, were assigned. Conductor spacing for the secondary service triplex and quadriplex were also defined so the proper inductive reactance would be calculated for the real-time analysis power flows. Also related, review revealed that the X/R for all transformer types was set to infinity, or 100% X, so industry standards were referenced to assign realistic X/R values for each transformer size and secondary voltage. Note that it is critical the X/R be defined since high power factor loads, which are most typically the case, will demand all active power. If a transformer is defined with entirely all reactive impedance, there will be much less voltage drop through the transformer impedance in the engineering analysis power flows than actually occurs on the system.

Overall, since most of the voltage drop may occur on the service transformer and secondary conductor, it is again expected, at this point in the real-time project, that secondary service modeling will be mandatory in the engineering models. This may or may not be the case, but this will be determined as real-time studies continue.

Once the circuit model has been defined at an acceptable level of detail and accuracy, it will be required that the utility implement a database maintenance system that will keep the database in-sync or up to date with the distribution system. It remains to be determined, in subsequent pilots, how detailed, accurate and up to date the database must be to obtain an acceptable level of accuracy in voltage and current flow results.

VII. LOAD ALLOCATION AND LOAD FLOW

We assumed that real-time analysis would be faster and easier to develop if we could start with existing engineering analysis applications used for years to accomplish traditional planning and operations studies. A very important goal of the first pilot was to prove that this could be done with our WindMil® Engineering Analysis software system [3].

Our assumption was that we could adopt WindMil's load allocation routine to do real-time load flow analysis. Note that a completed load allocation run is also a completed voltage drop, or load flow, run. Load allocation forces the summation of loads plus losses downline from a given load control point to equal the specified total amps per phase at the load control point. Distribution factors such as monthly kWh usage at each meter are used to distribute the load to closely match the actual usage.

In our real-time usage the load control point settings are set to agree with the latest reading from SCADA (Fast Data).

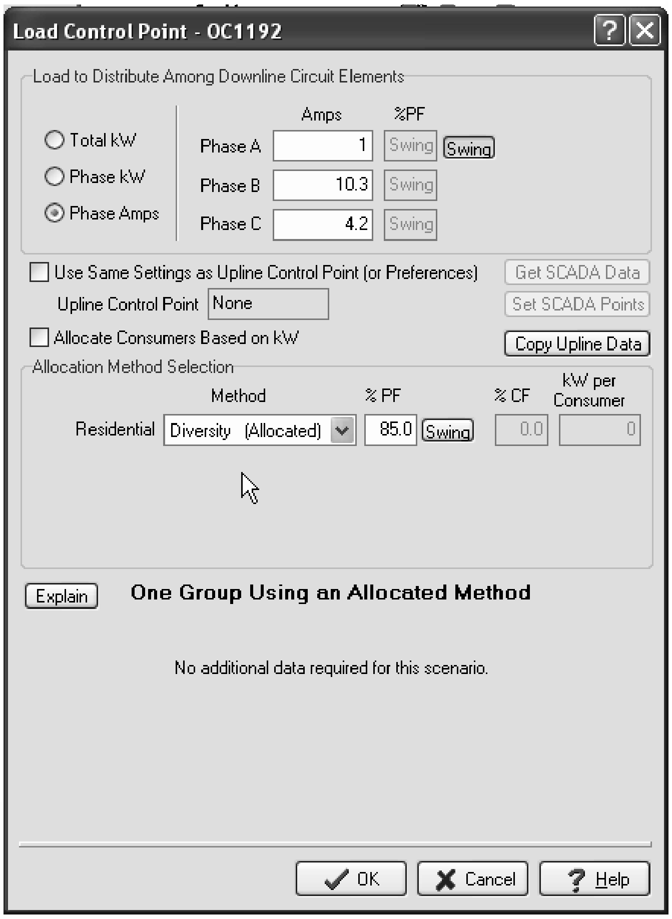

Figure 3- Load Control Point Settings

Figure 3 is an example of actual load control point settings for the Owen pilot feeder. SCADA provided the amps per phase values, which were gathered from the SQL database and entered into load allocation run parameters automatically by the real-time system. It was originally assumed that the power factor by phase could be set from SCADA, but the values initially obtained from this SCADA point were invalid. Thus, we allowed the load control point power factor to swing, or change as needed, when load power factor was set to 85%. We will test an automatic setting of power factor in our subsequent pilots. However, since this circuit was lightly loaded, the source power factor did not have a significant impact on calculated voltage and current flow results.

SCADA did provide voltage magnitudes for each phase in-sync with the amp reading time. A modification was made to the static load allocation routine to set the voltage magnitude on each phase at the load control point. The voltage on each phase at the load control point was then automatically set for each run to agree with SCADA voltage readings synchronized in time with the SCADA current readings. Starting each run with the correct load control point voltage is very important for the load flow result accuracy.

For real-time runs on the Owen pilot we used AMR kW readings to distribute load. Since the AMR system at Owen could only provide slow data for customer meters, we made the assumption that load distribution occurring right now, or at the time of the run, is similar to load distribution exactly one week, or seven days, ago. The AMR system could provide hourly readings, but usually these reading were as much as six hours old by the time all meters on the feeder could be read.

VIII. CALCULATED VOLTAGE AND CURRENT RESULTS

As noted above, since load allocation uses load flow to calculate losses, once the load allocation run is completed a load flow solution is also completed. Then, the real-time application need only run load allocation to obtain the calculated voltage and current results. Much work in subsequent pilots needs to be done to determine the accuracy level accomplished and what is required to obtain a given accuracy level.

Accuracy verification of voltage results can be determined by comparing real-time results with the AMR recorded voltage for that hour. Real-time runs are completed within seconds of event time when the kW and voltage for that time is not yet available; however, hours later the recorded voltages for that time are read and stored in the SQL database so that comparison of the calculated voltage to the measured voltage is then possible.

Voltage Accuracy Requirement #1: Voltage accuracy is first dependent on setting the load control point voltage and currents to the appropriate readings from SCADA. In the pilot we forced the timing of runs to use hourly SCADA measurements.

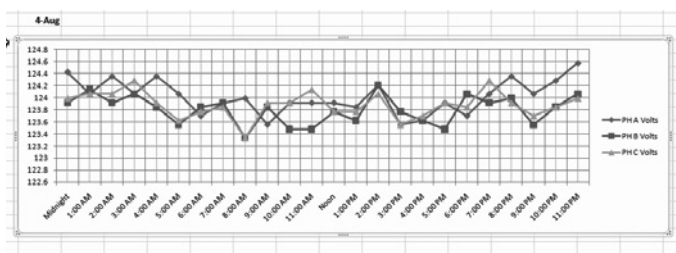

Figure 4 - Aug 4th SCADA Voltage Readings

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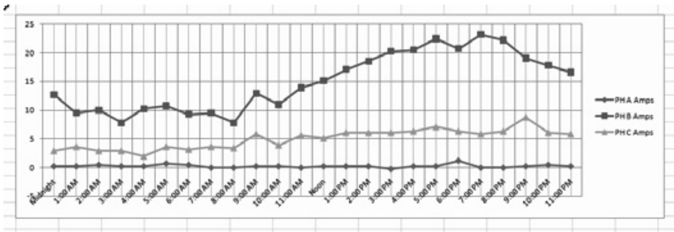

Figure 5 - Aug 4th SCADA Current (Amps) Readings

Figure 4 is a graph of the August 4, 2010, voltage readings at the load control point and Figure 5 is a graph of the Aug 4, 2010, current flow readings.

Since SCADA voltages were instantaneous, and AMR voltages were 60 minute averages in all runs to date, we failed to meet the first requirement of obtaining appropriate voltage readings at the load control point and therefore, all voltage comparisons are invalid. Once we change SCADA and AMR readings to be made using the same time interval, we will again attempt to compare calculated voltage results to measured results.

We are working with the SCADA and AMR vendors to adjust both to report a voltage average over a five minute time interval. We believe that using instantaneous voltage readings will result in very difficult timing synchronization problems. Assuming that instantaneous voltage readings will be spiky, being off in time even a few seconds could result in large voltage differences. We don't believe that a long interval, such as 60 minutes, will provide enough resolution to be useful. For that reason, we want to try the five minute interval. Hopefully, both SCADA and AMR will prove to be easily adjusted so that different time intervals can be tested.

VOLTAGE ACCURACY REQUIREMENT #2: The next known factor required to obtain accuracy is that the circuit be accurately modeled to match system configuration as required to provide an accurate impedance model from substation to each meter location.

The Owen pilot circuit is modeled accurately, as required, to define the primary impedance model but does not have accurate transformer impedance definition and has no secondary line definitions. For Owen and other systems with a similar model, we should be able to obtain voltage accuracy to the primary terminal of distribution transformers, but not voltage accuracy on loaded transformer secondary terminals and loaded secondary lines. It is assumed that primary voltage accuracy may be enough to serve primary engineering and operations decision making.

Where it is possible to model accurately to each meter, voltage comparisons should be possible between calculated and measured for all meters. Where, as is the case at Owen, only primary definition is available, voltage comparisons will only be possible on meters with very little load on transformer and and secondary line. Enough such meters should be present that we can obtain the necessary voltage comparisons on this and subsequent pilots.

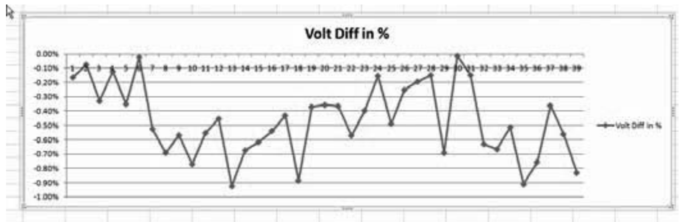

Figure 6- Volt Difference in Percent

While not valid because of different time interval voltage measurements on SCADA and AMR, Figure 6 does show it is possible to compare calculated voltage to measured voltage.

It will be necessary to use bellwether meters to establish accuracy in real-time. Bellwether meters are AMR/AMI meters that can be read in real-time (as fast data) and thus make it possible to determine accuracy in real-time. It is assumed that all AMR vendors can read a small set of selected meters in fast data time. Our plan, as we move forward with pilot projects, is to test and prove that enough bellwether meters can be specified and read to allow voltage accuracy determination in the real-time, as well as to set the voltage accurately at regulator banks and to establish the on/off status of switched capacitor banks.

Determination of voltage at regulator banks, and on/off status of capacitor banks, is very important to our ability to define the circuit model at a level required to calculate accurate voltage and current flow results. It remains to be determined in our pilot studies whether this is possible.

Voltage Accuracy Requirement #3: SCADA amp readings are very fast and can be assumed to provide accurate real-time total load levels at each SCADA point, usually at feeder bays. The total real-time load can be established for each run at each SCADA point. However, we must assume that the distribution of that total load is very important to the level of voltage calculation accuracy. For example, if 90% of the load is located on the first half of the feeder, we would expect very different voltage and current flow results than if 90% of the load is located on the last half of the same feeder.

We must assume that actual feeder loads will move, or change distribution, based on time of day, day of week and holiday situations. Additionally, there could be other factors, such as weather, that change load distribution. Load allocation accounts for distribution of load by use of one or more load distribution factors. In static load allocation, transformer kVA, monthly kWh and other data may be used. None of these will account for hourly changes in the distribution of load which it is assumed will significantly impact real-time calculation results. If this were not the case, then accurate real-time grid analysis could be accomplished using only SCADA total load data and would be much easier to accomplish.

We expect that some utilities will have AMI systems that are capable of reading kW and voltage on all meters on a feeder in fast data time and that we can use kW readings on all meters close enough (one to five seconds) to the SCADA event time for the load distribution factor. It is also expected that some MDM systems will be available that can accomplish accurate state estimation of the kW level for each meter such that the estimated kW at time of SCADA event time can be used. With either of these options, we should be able to improve the level of calculated accuracy by more closely following the actual shift in distribution of loads.

However, we have assumed, and we will use pilot projects to test and prove, that using AMR readings at the same time one week ago will provide an acceptable accuracy level. This is important because the fast data AMI and state estimation MDMs will not be commonly installed for some number of years. As we progress with pilot studies, we will establish the level of accuracy possible with this method as well as work on algorithms to improve accuracy.

While the "same time, one week ago" theory may work for the large number of small commercial and residential meters on a typical distribution feeder, we know that it will not work for large commercial and large power meters. It will be important to have fast data meter readings for these meters, since their impact on the feeder is large enough to greatly affect accuracy in real-time calculated results. As we progress with pilot studies, we will try to determine at what percentage of feeder load it becomes necessary to have fast data metering on large kVA loads.

IX. Data Display and Reporting

In the longer term, if we are to make real-time grid analysis a commercially viable product, it is very important to display and report results in a way the makes it possible to manage, engineer, and operate the distribution system more efficiently than is possible without real-time analysis. We are first focused on testing and proving that real-time analysis is technically and economically possible. It is expected that we will be doing pilot projects for this purpose for at least the next two to three years. With this being the case, we are comfortable that display and reporting of results can and will be defined, at least at the minimal level, during this process.

X. Summary

It is expected that we will have much more to report as we expand and continue the pilot at Owen and start additional pilots at South Plains, Oklahoma Electric, and Minnesota Valley. We will report on additional progress in our presentation to the REPC Conference next April.

At this time, it is evident that we know far less about doing real-time grid analysis than we anticipated. We know the following:

1) It is possible to build the IT platform necessary to collect and access necessary data.
2) It is possible to modify existing engineering analysis applications to run automatically in real-time.
3) It is possible to compare calculated results to measured results post event time.
4) It is very important to coordinate the definition of voltage reading between SCADA and AMR/AMI.

Issues that we know must be tested and proven are:

1) Is it possible to define SCADA and AMR/AMI voltage readings to a specified time interval?
2) What level of circuit modeling accuracy and detail is required to obtain the necessary level of accuracy?
    a. What is the necessary level of accuracy?
3) Is it possible to define and read bellwether meters?
    a. To establish large power usage
    b. To establish regulator voltage
    c. To establish capacitor on/off status
    d. To establish real-time accuracy
    e. To improve real-time accuracy
4) Is it possible to build a circuit model with impedance accuracy to the meter?
    a. What level of impedance accuracy and model detail is required?
5) Is it possible to up-scale single feeder pilots to the entire system?
6) What reporting and display is required?
7) And many more issues that will become obvious as we progress.

XI. References

[1] Jim See, Wayne Carr and Steven E. Collier "Real Time Distribution Analysis for Electric Utilities" 2008 IEEE Rural Electric Power Conference

[2] Greg Shirek, Brian Lassiter, Wayne Carr and Bill Kersting "Modeling Secondary Services in Engineering and Mapping" 2010 IEEE Rural Electric Power Conference

[3] https://milsoft.com/smart-grid/

XII. BIOGRAPHY

James D. See, P.E., received his BSEE from the University of South Florida in 1973. He has broad engineering experience with several electric utilities. From 1971-78, he worked at Florida Power Corp., St. Petersburg, Florida, first as a coop student then as plant engineer. He spent the next twenty years over the engineering department at Unitil, Concord, New Hampshire. Since 1998, he has been working in the cooperative utility industry, first at New Hampshire Electric Cooperative, Plymouth, New Hampshire, from 1998-2005 and is presently working for Owen Electric Cooperative, Owenton, Kentucky. As VP of technology at Owen Electric, he is responsible for IT and deploying smart grid technology. He is currently coordinating the implementation of two smart grid

grid grant projects and working with the University of Kentucky on student smart grid grants. He is a registered-professional engineer in the state of Kentucky and a member of IEEE.

Steven Latham received his B.B.A. in Management Information systems from Texas Tech University in 2000. He also received his M.B.A from Wayland Baptist University in Management Information Systems in 2004. Steven also holds certifications from both Cisco and Microsoft. He has been working for South Plains Electric Coop in Lubbock, TX since 1996 in many different rolls. Starting in 2000 he became the Manager of Information Technology and became more involved in many aspects of the South Plains' technology needs. He has been involved in the implementation and maintenance of the DisSPatch OMS system. As the AMI system has moved forward Steven has helped integrate it with other systems to better utilize the technology.

Greg Shirek, P.E., received his B.S. in Electrical Engineering from the University of Wisconsin-Platteville in 1999. He has broad experience in distribution system planning and protection, transmission planning, DG interconnection studies, arc flash analysis, harmonic assessment and mitigation, and reliability analysis having worked for 10 years as an electric utility consultant for Power System Engineering. In 2008, he joined Milsoft Utility Solutions, Inc. as an Engineering Analysis Support Engineer. He is a registered professional engineer in the state of Wisconsin and a member of IEEE.

Wayne Carr, P.E., received his BSEE from the University of Texas at Austin in 1970. From 1970 to 1976, he held various engineering positions at Houston Lighting and Power Company. From 1976 until 1980, he was the staff engineer for Erath County Electric Cooperative in Stephenville, Texas. From 1980 to 1989, he was a consulting engineer for electric utilities, focusing on planning and operations of distribution systems. Since 1989, he has been the Chief Executive Officer and Chief Development Engineer for Milsoft Utility Solutions, Inc., in Abilene, Texas. As Chief Development Engineer, he has been instrumental in the development and implementation of computer algorithms for the simulation and evaluation of electrical distribution analysis systems. He is a member of IEEE and has maintained his standing as a registered Professional Engineer in Texas since 1976 and The National Council of Engineering Examiners since 1987.