

Grid Transformation Workshop Results

April 2012





Preface

A two day conference was held on November 1st and 2nd, 2011 at Argonne National Labs near Chicago, Illinois. There were 48 industry executives and researchers in attendance representing 25 different utility companies and universities. The attendees were separated into 6 working groups and they were instructed to identify the needs, state-of-the-art, gaps and barriers for each of the major topic areas that are part of this project. These areas are: Developing a seamless geospatial power systems model, setting-less protection method, integrated energy management system, and seamless power system analytics.

This report supersedes the previous report Grid Transformation Workshop: Advanced Reading Material Product ID 1024659. The material in this report builds upon and slightly revised the concepts presented in the original report based upon feedback received during the workshop.

Background

In an earlier whitepaper entitled *Needed: A Grid Operating System to Facilitate Grid Transformation*, EPRI Product ID 1023223, we set the stage for a new grid operating system called Grid 3.0. Since that time we have identified four core research areas that are required to achieve the expected outcome. These research areas are called: seamless geospatial power system model, seamless power system analytics, integrated energy management system and setting-less protection method. While each area has significant work independently, they are also interdependent on each other in many ways and therefore all need to be considered to fully achieve Grid 3.0.

Seamless Geospatial Power System Model – The explosion of data from “Smart Grid” Intelligent Electronic Devices (IEDs) and the deployment of distributed generation in the form of wind and solar systems has significantly increased expectations of utility systems and stressed the analytics, control schemes, back office systems and applications including devices that are currently deployed to manage and control the grid. Increasingly these systems are being asked to provide an integrated geospatial view of such diverse applications as power flow management, fault detection and location, critical asset identification and utilization, outage management, work force utilization, inefficiencies, loss identification, theft, distributed generation status and control and cyber and physical security threats. One of the problem areas of all these systems is namely the lack of a standard, seamless data model that can be used across all the ap-

plications. We will explore the basics of data modeling, identify the current state, discuss the drivers for change, and propose a future state and the challenges that lie ahead.

Setting-less Protection Method – The capabilities of protective relays have increased dramatically as more powerful microprocessors are used in modern numerical relays. At the same time the complexity has increased primarily because numerical relays are set to mimic the traditional electromechanical counterparts. In addition, despite the progress of the last few decades, some problems persists: we still do not have good 100% reliable approaches for certain fault types, such as high impedance faults, faults near neutrals, etc. Also the training requirement for protection engineers is ever increasing and requiring even broader based knowledge that before. We will examine several approaches that should lead to setting-less protection schemes. The approaches to be examined are adaptive relaying, component state estimation approach, substation based protection and pattern recognition based approach. Each approach will be evaluated with the following criteria: feasibility, dependability, security, reliability, and speed of protection. It is expected that these approaches will lead to or form the foundation for true setting-less protection schemes.

Integrated Energy Management System – Several of the pervasive limitations of power control centers at the levels of architecture, data

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modeling, computation, visualization and integration need to be explored in this research. Control centers that control the transmission-generation grid, known as energy management systems (EMS) are organized in a hierarchy of two or three levels depending on the size of the interconnected grid. These EMS, first using digital computers in the 60s, have evolved gradually over the last decades but now major transformation is essential to support emerging power system operations and grid objectives. The expanding power grid requires operation and control of system behavior that occurs at temporal and spatial scales, different from the scales traditionally considered by the EMS. New technologies in measurements, communications, computation and control make such transition to a new generation of EMS possible. These same technologies are increasingly being applied to the distribution system and new generations of distribution management systems (DMS) are now being deployed that are increasingly connected to the EMS. We will explore how these new technologies may be applied to centers for operations ranging from millisecond to day ahead, spread over whole continents.

Seamless Power System Analytics - Power system computer applications are fundamental to the successful operation and planning of power systems. The current approach to power system analysis has developed over the last several decades in a piecemeal fashion where the various applications run separately using their own system models and formats. Although these tools have improved, the programs are still built upon core technology and software architectures from decades ago, each developed individually, for its own unique purpose, often with legacy code implementing old

algorithms, all designed for sequential computing hardware. Most existing applications have their various components tightly coupled and non-separable. The internal code is not structured and often very old. In addition, external data interfaces are unwieldy, the user interface is weak, and there is usually no centralized engine to house the numerical methods used in the application. Updating or extending such software is very tedious; it is often easier to create new software completely. Achieving interoperability for such applications is extremely cumbersome if not impossible.

These limitations need to be overcome by state-of-the-art analytical tools that can support modernization of the electricity industry. New models and tools are required to handle emerging needs driven by increasing model size, renewable penetration, phasor measurement-based wide-area monitoring and control, and the need to share models, analyses, and results across a wide spectrum of organizations. Current and future computing requirements necessitate an integrated approach that builds upon state-of-the-art algorithms, hardware and modern day methods for data management across a shared environment.

The objective of the research is to develop and identify possible approaches towards seamless power system analytics. To this end, we have inventoried current analytical needs, evaluated existing gaps and barriers that prevent seamless analysis to take place, propose design requirements for seamless power system analysis, and identify software architecture options for future power system analysis applications.

Seamless Geospatial Power System Model

Background

Data Models

A data model is a tool used by software developers and business professionals to describe data and its format/structure, actions, relationships and information exchange in the development of a system. An instance of a data model can include 3 different types of schema – Conceptual or HDM high-level data model that is used to communicate core data concepts, rules and definitions to business users and developers; Logical model that consists of tables, columns, object oriented classes and XML tags; and Physical model that deals with where and how the data is stored. If you dig deep enough into almost any utility system, at its core you will find a data model that describes the fundamental data elements that are used in the application. Some examples include:

Electrical Models

There are numerous examples of models that define the interconnection of various grid devices/elements. Two of the most common are the Bus-Branch and Bus-Breaker models that describe electrical interconnectivity. They are a relatively low level description of the grid primarily dealing with electrical device characteristics/parameters and connectivity. They may optionally have geospatial attributes and some asset information.

Bus-Branch: This model (Figure 1, below) is used for power flow analysis a bus-branch model is used. This type of model does not represent detailed switching schemes since its purpose is to primarily model power flows thru active portions of the grid.

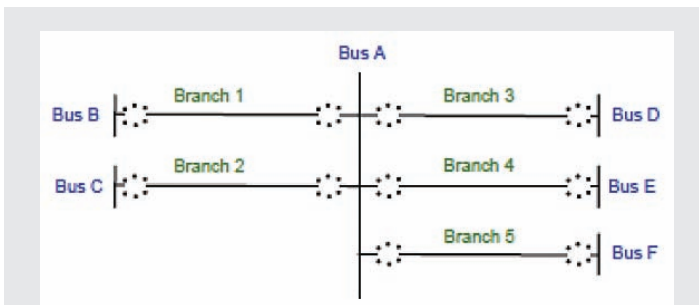


Figure 1 – Bus – Branch Model

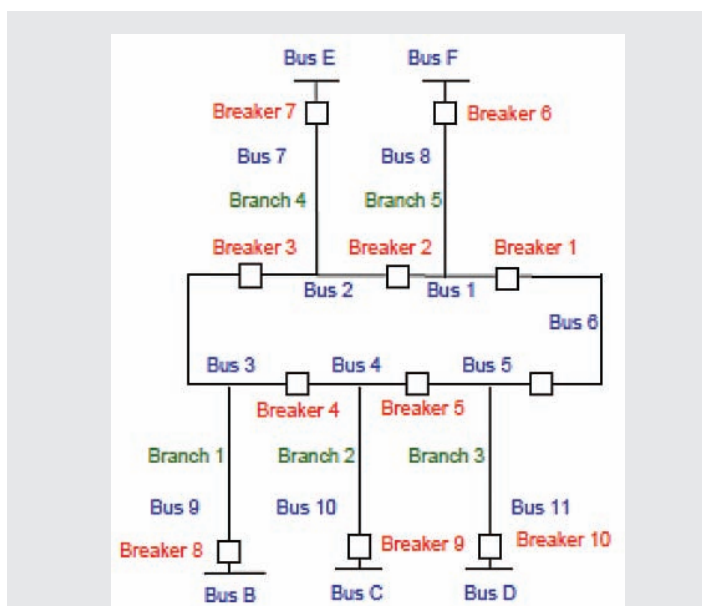


Figure 2 – Bus – Breaker Model

Bus-Breaker: This model (shown in Figure 2) is more commonly used in SCADA systems where representing the current state of the grid is critical. Here the location of switches and breakers are modeled as well as the current state—open/closed/bypassed/OOS.

Historians/Time Series Data

These are applications that specialize in storing millions of sensor readings from IEDs (Intelligent Electronic Device) and RTUs (Remote Terminal Unit) in a “point tag” organized time series database that facilitates storage, compression and retrieval. The data model for these applications is relatively simple including a “point tag” ID, a long description of the point, units of measure, compression ratio and scan rate. For very high speed data (several samples per second, time stamped) such as the data collected by Digital Fault recorders (DFR), Power Quality recorders (PQ) or Phasor Measurement Units (PMU) one of the most common formats is the IEEE COMTRADE format.

GIS – Geographic Information Systems

These systems are designed to manage and visualize geographic maps with utility assets and their status superimposed over the maps in a “layered” format. Their data models and analytics are specifically designed to perform geospatial queries. Increasingly these systems are being integrated into traditional SCADA, work force management and outage management systems to provide a “real time” geographic view of the assets status. For example, the graphic below is a snapshot from a network monitoring application that has integrated Google Earth into a geographic display of the network status.

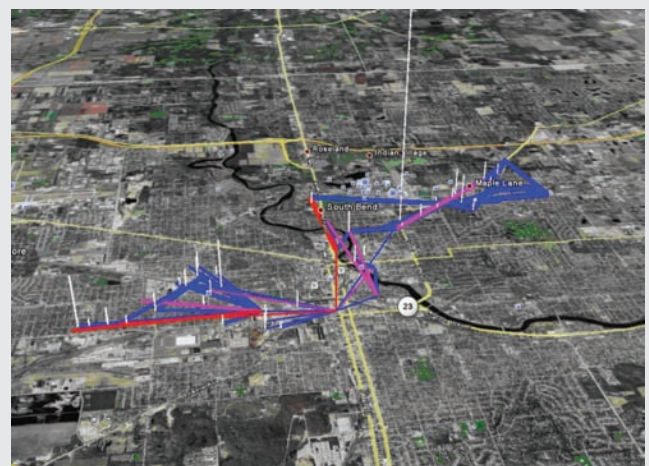


Figure 3 – Geographic Information Sample

CIM – Common Information Model

At the “other end” of the data model spectrum is the CIM model. It is an extensive model that includes such diverse classes as Assets, Work, Customers, Metering, Wires, Generation, LoadModel, Outage and Protection. Each of the classes contains properties and attributes so for instance, the Metering class defines meter registers, reading values, service point locations, etc and relationships to other classes such as Customer and LoadControl (see Figure 4).

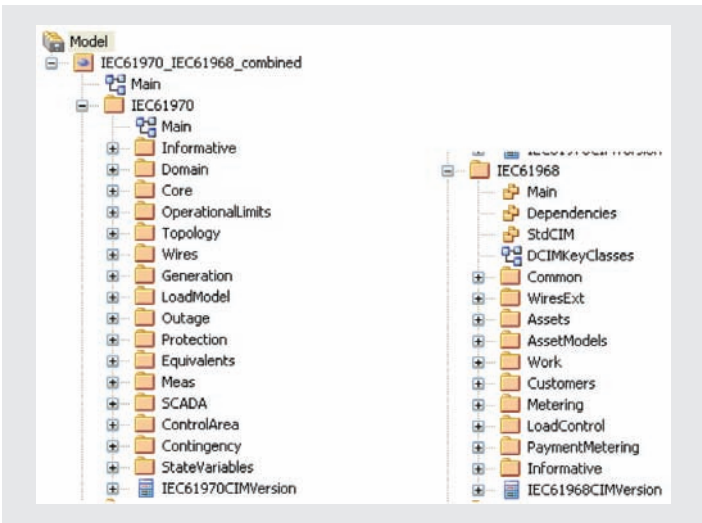


Figure 4 – Example of Common Information Model (DIM)

Others

There are numerous other examples of utility applications such as SCADA systems, outage management systems and field force management systems that implement data models to enable geospatial



Figure 5 – Google Earth Map Including Feeder Topology and Smart Meter Locations

(physical) and grid centric (electrical) views of the grid. For long event horizon planning tools the data models typically include long transaction “versioning” capability so that work can be tracked through the life cycle of the project. Figure 5 shows an example of a Google Earth map that includes feeder topology and smart meter locations.

Protocols

Protocols are a set of rules and message structure that two endpoints in a communications network use to communicate with one another. In transmission and distribution applications (IED <-> SCADA) the legacy protocols that still dominate are DNP 3 and Modbus. These protocols distinguish themselves by having very short message formats that minimize the exchange overhead when used with slow speed communication paths such as RF links. When bandwidth is not at a premium, the 61850 protocol is more appropriate due to its “self describing” nature that minimizes “up front” configuration issues. This protocol was specifically designed for substation automation and has an abstract data model (show in Figure 6) that has been mapped to several other protocols as well. These protocols are typically used to “shuttle” data between two endpoints and their respective data models. In addition, there are low level transport protocols like ANSI C12.22 for meter data transport and the IEEE 37.118 protocol for transmission of data between a PMU and PDC.

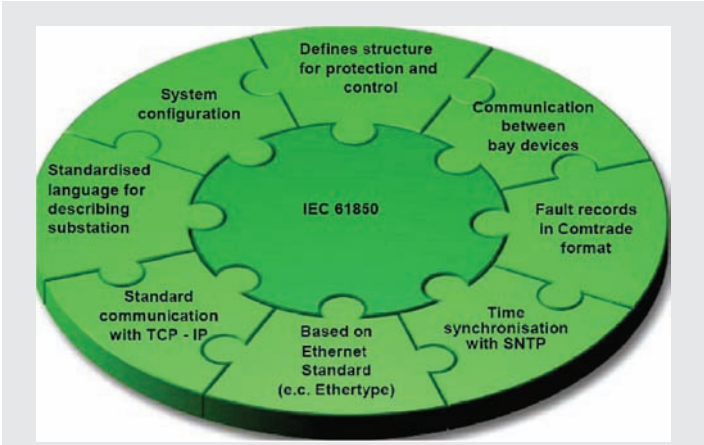


Figure 6 – Example of IEC 61850 Protocol Abstract Data Model

Current State

Data Model Stew

Unfortunately, this data “model stew” of numerous applications with specific proprietary implementations has lead to significant interface accuracy issues, lack of functionality and maintenance



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headaches. As one major utility has publicly reported, the manpower to maintain and synchronize 17 different data models is time consuming and costly. To further complicate the issue, the popular communication protocols are not well aligned with the data models. Most of the communications protocols were designed with an “IED in mind.” As a result the messages are cryptic, sensor centric and require translation/modification to import/export data from/to an application data model. In addition to problems with back office integration this lack of a common database model affects distributed control systems as well. This is one of the reasons that S&C Electric introduced their Intellinode™, module that allows equipment from other manufacturers to function as a team member in an Intelliteam SG™ network. Using the same operating system and communications protocol between all the devices significantly reduces the complexity of the system and increases functionality.

Drivers for Change

Explosion of Data – PMU, IED’s, Smart Meters

Deployment of Smart Meters can significantly increase data volumes. A typical residential Smart Meter will have at least 3 recording channels (TxKwhr, RxKwhr, Voltage) as well as event flags. (Typical C&I meter may have 10 recording channels) If a utility deploys 4MM meters (for example PG&E) and records interval data at ½ hour intervals the amount of data stored daily in a database will exceed

1 billion rows/day. This “fine grained” data will allow new insight into grid performance provided that we have architectures, databases and data models than can handle the data volumes. Figure 7 is a 3D geospatial mesh built from 130,000 Smart Meter voltage readings taken on a hot summer’s day in Chicago.

Phasor Measurement Unit (PMU) data also presents a problem because of the high speed sample rate and streaming nature of the data. Depending on the sample rate and number of channels sampled the amount of continuous streaming data can reach 6Kbytes/second or >500MB/day/PMU.

Collapse of Business Boundaries and the Demand for Integration

One of the surprising consequences of Smart Grid technologies is the elimination of the barriers and distinction between the meter side of a utility and the distribution operations group. Now that Smart Meters are used as “bell weather” meters for CVR (conservation voltage reduction) projects and the meter data is used for numerous grid optimization projects there is an increasing demand for “situational awareness” dashboards that integrate grid operations, outage management and customer notification into a unified view/system.

Regulatory and Green/Efficiency Pressures

Whether it is California’s solar initiatives/incentives that have funded >98,000 solar installations state wide (948 MW) (see nationwide

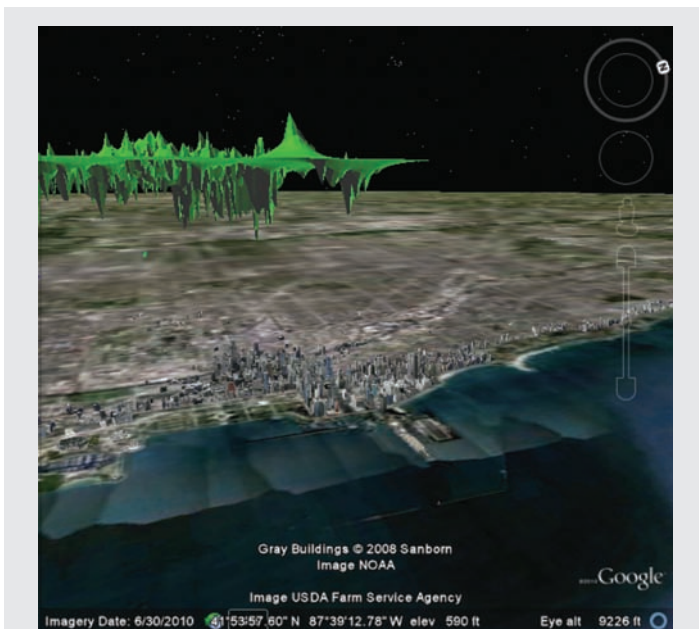


Figure 7 – Example of a 3D geospatial mesh built from 130,000 Smart Meter voltage readings taken on a hot summer’s day in Chicago

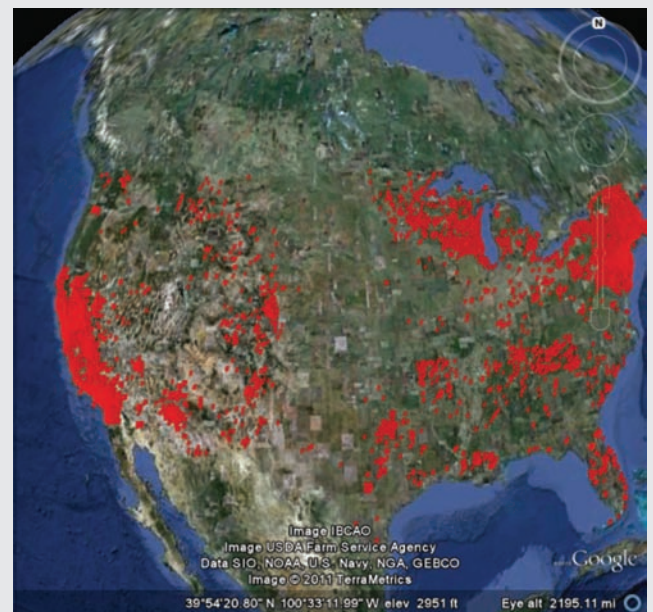


Figure 8 – Situational Awareness Example



map) or Illinois' focus on outage communications to customers and storm restoration/response due to unprecedented summer storms there is increasingly a need for utility back offices application integration that provide a real time situational awareness of the grid and customer status.

Distributed Generation – Micro Grid Control, Neighborhood DC Bus

As wind farms, both large and small begin to dot the landscape, control of these distributed generation assets is increasingly important. There are numerous projects worldwide attempting to integrate wind turbine controls into the protection/regulation schemes of the local micro grid. This will demand a new level of interoperability between IED's.

New Transmission/Distribution Technologies and IED Capabilities

SST, FACTS, FCI

In the past, IED processors were small low cost 8 bit processors with limited memory and computing capability. Today's IED's are extremely capable 32 bit processors (i.e. ARM 9/11 cpu) with DSP capability and a robust operating system with a full TCP/IP stack. These processors will be embedded in the new generation of IED's, such as Solid State Transformers (SST) as shown in Figure 9, Fault condition indicators (FCI) as shown in Figure 10, and Flexible AC Transmission Systems (FACTS) as shown in Figure 11, generating large quantities of new sensor data and allowing local peer to peer controls. This will demand more IED interoperability between distributed devices.

Computing Environments

Multi Core Processors

It is now common to be able to purchase low cost processors with 4 or more parallel processing cores. Unfortunately, most of the utility back office applications do not effectively harness this multi-threaded parallelization.

Shared Nothing Databases

Traditional databases do not effectively harness the parallel processing and simultaneous disk transfer capabilities of today's computing platform. Fortunately, there are several emerging "shared nothing" segmented databases that promise to exploit parallelism and address the volumes of data that is being created and stored.

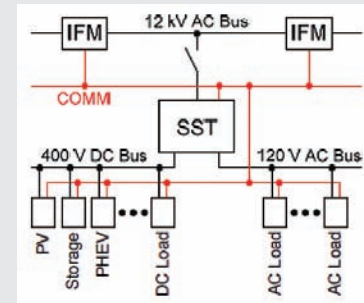


Figure 9 – Example of Solid State Transformers

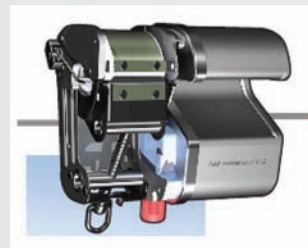


Figure 10 – Fault Condition Indicators

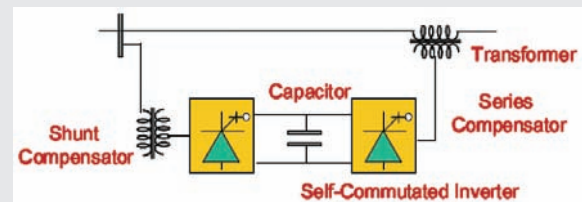


Figure 11 – Flexible AC Transmission Systems

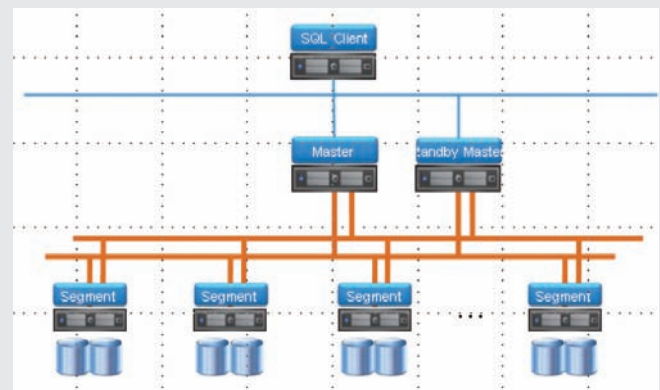


Figure 12 – Example of a Shared Nothing Database



Figure 13 – Sample Consumer Portal

Consumer Expectations

Increasingly, consumers are demanding that they have an active part in the management and control of their energy usage. Time of day pricing and ultimately “real time” pricing programs could significantly change the average customer’s usage profile as they respond to pricing signals. In home devices and even iPADS and iPhones are being used to monitor home energy usage, thereby adding another dimension to the data modeling challenges – customer profiles, preferences and behaviors.

Challenges

Diverse Data Types

The variety of data types continues to grow as unique devices like PMU’s and SST are deployed. Data types include: numerical, text, streaming, images, movies, animation, geospatial and complex/custom (PMU, Oscillography). This variety will challenge our data models and architectures

Data Rates – Hi (Real Time) vs. Low Frequency Rates

High frequency and streaming data feeds are difficult to model, analyze and store. Significant work remains in this area to accommodate these data rates.

No Standard CIM Physical/Logical Schema

Today, the CIM model exists in a Conceptual schema form. Numerous vendor have implemented their proprietary versions of a Logical and Physical CIM schema but no standard implementation has emerged.

Lack of Harmonization of Protocols and Data Models

There have been attempts at harmonizing protocols such as 61850 with the CIM model but the process is complex and tedious (190+ page report).

Vendor Momentum

Given no external forces/options, vendor’s will continue to use their proprietary data model implementations to maintain a competitive advantage and utilities will have no choice but to adopt them in order to gain the increased functionality that is provided.

Future State

Common Distributed Operating System

Given the current state of the industry it may seem like a “stretch” to recommend a common embedded operating system for distributed grid monitoring/control. However it should be noted that probably >90% of ALL transmission and distribution data today flows thru a ubiquitous embedded operating system, Cisco IOS. It is also hard to deny the success of Apples’ iPhone/iPad IOS and Google’s Android operating systems. In the utility industry, the question is who will be the Cisco/Google equivalent to champion and successfully demonstrate a viable distributed operating system? Possibly an EPRI led collaboration or maybe a consortium such as the NCSU FREEDM System Center <http://www.freedom.ncsu.edu/index.php?s=1>. As you can see from Figure 14 below their goal is distributed grid intelligence and advanced

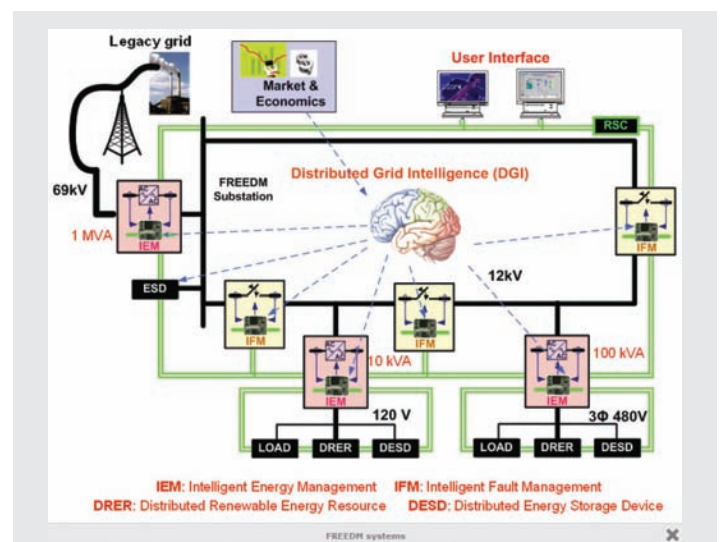


Figure 14 – Distributed Grid Intelligence and Advanced Devices with “Plug and Play” Capability



devices with “plug and play” capability that will better utilize long term renewable energy. Only time will tell if any organization will develop this capability, however what is clear today is that the hegemony of proprietary vendor data model implementations and incompatible protocols of today will not address tomorrow's grid needs.

Common CIM Logical/Physical Schema

Implementing a CIM based logical and physical schema today is a daunting and costly task. This barrier to interoperability needs to be addressed.

CIM Validation Suite

It is very difficult to establish a “CIM Compliant” validation program when all you have is a Conceptual schema as there are numerous interpretations of the standard. Once you have built a common CIM Logical/Physical schema a rigorous “CIM Compliant” suite/program can be established.

CIM – IED/Embedded CIM

The CIM model is extensive and includes support for meters, wires, generation, outage, work and customers to name just a few. Obviously an IED doesn't need all of these domains/classes so a CIM logical and physical model for IED's needs to be developed. When used in conjunction with a common distributed operating system and the next generation of “smart” IED's the development focus would shift from build interfaces and communicating data to what control algorithms are effective in managing microgrids and renewable distributed generation.

CIM Extensions for Complex Data Types and Control

As new device types are added to the electric grid, CIM will need to be continually extended to support these new complex data types. Continue the current work on CIM for Dynamics to include control models at both the transmission and distribution level.

Standard CIM ESB (Enterprise Service Bus) Implementations

Increasingly, ESB's (Enterprise Service Bus) are being used as the connector/transport for utility back office system integration. Currently, this level of integration/customization is primarily done by ISV's using custom ESB rules/logic. Developing standard ESB connectors to popular utility systems could lead to a more “plug and play” environment.

Harmonization of Protocols and CIM

In the long run, there is no substitute for an open common distributed operating system to facilitate collaboration and development of new applications. However, in the interim efforts should be funded to develop a “working” open interface between 61850 (and legacy protocols) and a physical CIM schema.

Conference Results and Recommendations

Need a Common Data Model

There was general agreement that the current multiple database/model approach was rapidly becoming unmanageable and would not scale to meet the needs of the emerging Smart Grid. CIM appears to be an acceptable starting point to build a logical and physical model but it will require extensions to fully support all aspects of the utility business. As you can see from Figure 15, comments from all groups support this recommendation and included: *too many databases, need a single model, need seamless model, need model interoperability, CIM needs extensions and need one bidirectional model of the system*. Since the CIM model is quite extensive and covers a broad spectrum of applications, the logical/physical model should be developed and bundled as components so that portions of the model can be used as appropriate. (e.g. CIM lite for IED's)

Overall management of the CIM development should be managed by EPRI (see 6.1.3) but CIM extensions could be provided by companies with specific expertise in those areas. (e.g. – Metering – Silver Spring Networks; Distribution reclosers – S&C; FCI's – Sentient/SEL; SST – GRIDCO)

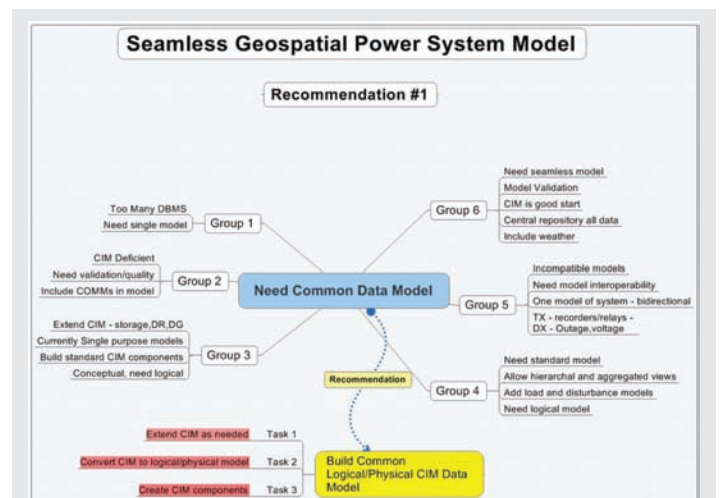


Figure 15 – Recommendation 1 Seamless Geospatial Power System Model



Need High Performance Computing Architecture

There was general agreement that the technologies behind today's utility systems were outdated and that in general the industry was unaware of the advances in parallel computing and parallel databases. Many of the computer codes are still written in Fortran and running on serial machines. Comments (Figure 16) included: *Industry not familiar with new technologies, need new architectures, big data challenge, need to harness more compute power, develop parallel algorithms, leverage expertise in other businesses.*

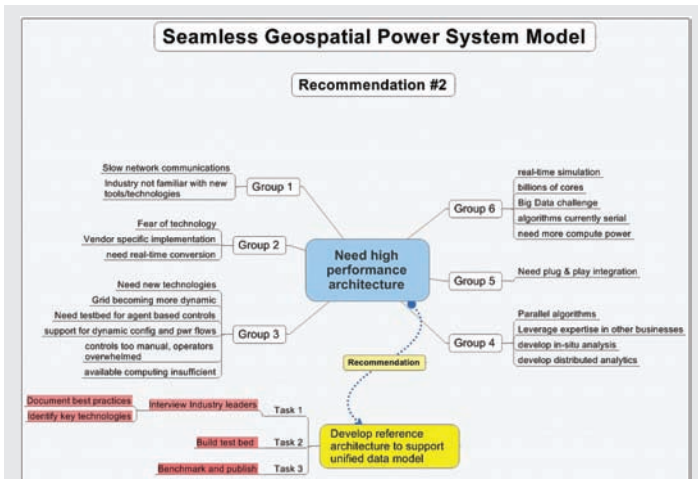


Figure 16 – Recommendation 2 Seamless Geospatial Power System Model

It was recommended that several industry leaders be interviewed – Google, EMC, Oracle, CISCO for example, to determine the best practices and technologies to use to deal with the use of a large seamless data model and to manage the big data requirements of the Smart Grid. Once the recommended architecture is selected a test bed/proof of concept lab should be established and used to benchmark data models, advanced databases and parallel algorithm performance.

Need Independent Sponsoring Organization

The attendees identified (Figure 17) *lack of funding, vendor proprietary technologies, lack of education, lack of planning and lack of leadership* as a primary barrier to development and adoption of a common data model. There was general agreement that an independent organization such as EPRI would be the best organization to sponsor this development for its members and the industry as a whole. The first step would be to identify industry partners such as the CIM users group and vendors who have adopted CIM as a standard to develop a roadmap for building a CIM logical and

physical schema as well as working with key vendors to extend CIM in those areas where it is incomplete. Once developed, regulators, vendors and the industry in general would need to be educated as to the benefits of incorporating the standard CIM model in all new utility applications.

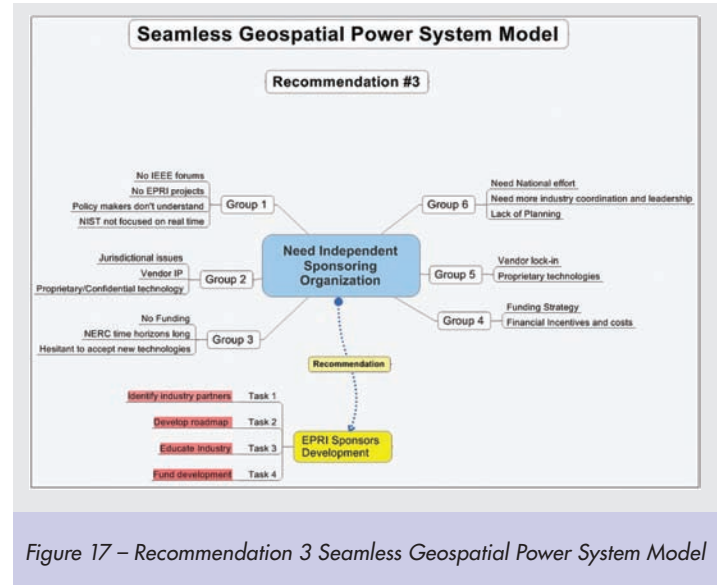


Figure 17 – Recommendation 3 Seamless Geospatial Power System Model

Integrated Energy Management System

Introduction

The first digital control centers were introduced in the 1960s to replace the hardwired analog control centers whose functions included supervisory control, data acquisition and automatic generation control (SCADA-AGC). In the intervening decades the advancement of information technologies has enhanced the functionality of these control centers many fold, but the general architecture of collecting and processing all measurement data at a central place has not changed. It is clear that this centralized architecture will not be able to handle the increasing volume of measurements and the faster wide-area controls that will be required for the operation and control of the future grid.

Measurements at the substations are sampled every few seconds and collected at the remote terminal units (RTU) which are then polled by the SCADA system. The new phasor measurement units (PMU) are sampling voltages and currents at 30-60 times per second at the substations but the present SCADA communication systems cannot transmit this rate of data to the EMS. The slow scan rates of the



present communication system is adequate for sending automatic generation control (AGC) signals but not those needed to control fast power electronic controls, like static VAR controllers or high voltage DC transmission lines.

In addition, more measurements are being installed in the lower voltage distribution systems all the way to smart meters at the customer level. Cheap communications can bring back at least the feeder measurements to a DMS for monitoring the distribution feeders and remote control of sectionalizers. The modern DMS is consolidating several separate functions like trouble call analysis, crew dispatching, automatic sectionalizing, integrated volt-Var control, conservation voltage control, etc. The main issue for DMS is less the development of technology and more the payback in energy savings and reliability.

The new measurement and control technologies have raised the expectation of more secure and optimal operation of the grid, which will be enabled by the evolving computation and communication capabilities. This paper explores what this means in terms of the needed evolution in control architecture, data modeling, computation, visualization, integration, etc. Although we explore these issues in separate sections below the intent is to show the inter-relationships between these issues. For example, the communications architecture influences the data modeling and management, and limits or enables the new and faster controls. Although much of the research and development are still done in silos – visualization, controls, optimization, etc. – we try to show in this paper that these issues are highly interconnected and the next generation of control centers will have to be designed by considering all these issues as a whole.

Control Architecture

The emerging power system control problems are complex and require more powerful functionality and capabilities. Therefore, the control architecture for the transmission-generation grid must be revisited. The present day control architecture for an interconnection consists of a hierarchy of control centers: (1) at the lowest level a SCADA system gathers all substation measurements from a defined region at a sampling rate of a few seconds; (2) the load-generation balancing function done by the balancing authority (BA) can be done at this lowest level or at the next level control center in the hierarchy (the tendency has been to combine SCADA regions into larger BAs); (3) to coordinate the grid reliability of the interconnected BAs a control center for the reliability coordinator (RC) at

the next level of hierarchy is designated to oversee the reliability of a large geographic region; (4) in North America the RC is the highest level resulting, for example, with about 11 RCs overseeing the Eastern Interconnection whereas in other regions in the world (China, India) there is one control center over the RC level that oversees the whole interconnection. All large interconnections in the world have evolved control center architectures of this type (Figure 18).

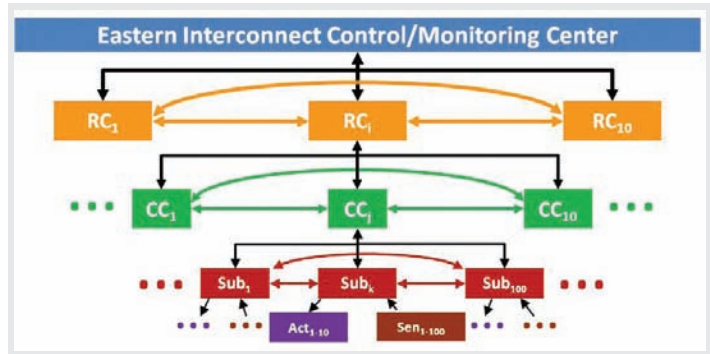


Figure 18 – Communication Architecture of EMS for an Interconnected Power Grid

Handling of Spatial Scales

As the interconnection size has increased, this hierarchical structure of control centers has gotten bigger resulting in real time data having to travel up the hierarchy and control decisions traveling down. Given that the present measurements are not time-tagged and the communication times are not tightly controlled, reliable automatic controls are difficult to implement in this structure. Thus the responsibility for control decisions, either manual or automatic, are kept lower in the hierarchy. To be able to do more automatic (thus faster) control to impact larger portions of the interconnection (wide-area) will require more communications of real time data and control signals with tighter specifications on communications performance.

Handling of Temporal Scales

Although phasor measurement units (PMU) are being installed rapidly at many substations, this real time data is being handled separately from the SCADA data. The future EMS will have to be designed to handle ubiquitous PMU data, that is, all SCADA points and more may become sources of PMU data. It is also obvious that not all of this data will be centralized even up to the SCADA control centers not to mention the control centers at the higher levels of the hierarchy. This means that the present data acquisition

procedures will have to be replaced by data transmission procedures that will have to be developed to support all the new applications. The data management issues are addressed in the next section but the applications, the communications architecture and data management are intimately dependent on each other and have to be designed together.

Enterprise Architecture

The control center architecture has always been independently designed and developed with no regard to the rest of the functions in the power company, leading to many difficulties of transferring data and decisions of one domain to another. The most glaring example of this is the incompatibility between the operations planning environment and the control center environment. The schedules and reliability considerations determined in the operations planning environment have to be transferred to the real time operations environment but there is no automatic way to do this.

Another consideration is that all the control centers in a given hierarchy, although connected, are not compatible with each other. Information has to be translated from one data frame to another as data (real time measurements, static system data, control signals) traverses the hierarchy. These inefficiencies get in the way of implementing the new seamless applications that are needed in the future grid.

Data Modeling

Unified Data Models

Unified models in which the divisions between temporal scales (e.g., operations and planning) and spatial scales (e.g. transmission and distribution network) are eliminated or abstracted to the application are desirable. As described in the previous section, a significant portion of the EMS applications are arising at the continuum of temporal scales from milliseconds (PMU) to day-ahead. Complex analytics, similar or superior to some of the existing planning tools, must be combined with enhanced functions to realize the required operational EMS tools. This will require a seamless underlying data model framework.

The lack of unification of data models is a pervasive problem in the power industry. To illustrate its complexity, consider Figure 19, which illustrates how various representations of a utility's power system network model can be found in a utility's EMS systems: Input Relational Database, Real-Time Database, Internal Bus-Branch Model, Exported Snapshot Planning Case, and CIM. None of these models are compatible with the Planning Case used in the off-line environment.

Several efforts such as the Common Information Model (CIM) provide standardized definitions of power system data. Presently, however, the vast majority of applications represented in Figure 19 continue to require converting CIM or other models to their native

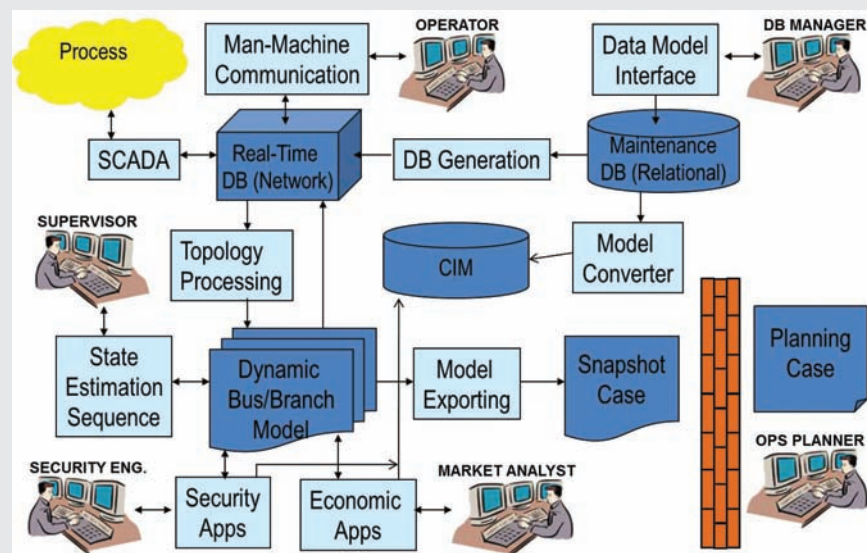


Figure 19 – Power System Models used in a Typical EMS System



underlying format. Recently proposed solutions rely heavily on model conversion from an operations model to planning cases, a method that essentially “changes the data model to support legacy applications.” Such methods do not support interoperability and will represent barriers in the long term.

Seamless EMS data modeling means that a common model is used across applications and across all relevant temporal and spatial scales. For instance, DMS data should seamlessly be propagated (either at data point or aggregated level) into the EMS database. If the ISO would like to “zoom in” into the utility model and have their applications take into consideration specific conditions of the distribution grid, that should be possible. (Today it is almost impossible to have applications or visualization that moves across control center boundaries.)

By the same token, PMU data must be integrated with SCADA primary data, model-based data, or application-generated data. Unified handling of the underlying new temporal scales represents a challenge. For instance, different ISOs use different temporal granularity for ancillary services optimization. Combined datasets must not only deal with synchronization, but also with non-unified granularity.

Support for Massive Data

The data architecture must support high volumes of data from PMU, substation automation, and smart meters. Models of these data must be compatible regarding geo-referencing, ID-ing, time-tagging, and verification for the various application scopes. Model data must be validated. Estimated data and parameters must be qualified.

The emerging power system will push the capabilities of existing historians and temporal databases, as well as of spatial databases. Power system domain-specific, on-the-fly processing of data for efficient storage and compression methods must be developed.

Machine learning and data mining applications are very promising tools that would provide powerful analytics and discovery. Such applications will allow exploiting the already significant amount of data being collected.

Support for Distributed Control

The electricity industry transformation requires deploying massive amounts of distributed renewable energy. It is not sufficient to just connect the source devices to the grid. The local controls, the system controls and the market functions must also become more distributed and flexible. There is a rapid trend towards distributed control evidenced in various efforts towards enhanced DMS systems,

and microgrid, building and home energy management systems. Ultimately, grid control will span all the spatial scales from interconnections to appliances. The data model used by the industry must therefore support such distributed control.

At the same time distributed control can take place at the ISO, providing either intra-substation or inter-substation (PMU-based) control. The data model must hence address system modeling, local data collection, local data processing, local storage, data exchange and relying, synchronization protocols, etc. Beyond raw data, the information and the communication architectures associated with the EMS applications required for control will play a fundamental role in enabling distributed control use cases.

Computation

The first on-line analytical applications were introduced in the 70s with the first EMS and consisted of state estimation and contingency analysis, that is, steady state computation of the transmission grid. With increasing computation power and better algorithms, contingency analysis has been extended to dynamic analysis. In the 90s when next day markets were introduced, optimization methods were implemented to solve repeated optimal power flows. These are all computationally intensive applications and more sensitive to numerical convergence especially in the on-line environment using real-time data.

A market region usually covered many EMS territories and these markets encouraged higher levels of power transfers over longer distances. This required applications that covered regions encompassing many EMS jurisdictions thus requiring coordinating the same application over several control centers. The results so far have been less than satisfactory because of data exchange limitations but even if the data exchange becomes seamless, the distributed computation needed to make the application seamless has to be developed. These techniques range from numerical computation advances (advanced matrix factorization, numerical integration, generalized robust estimation, etc.) to computation infrastructure such as cloud and GPU computing.

Visualization

Visualization of the real time condition of the power grid is the best monitoring tool the operator has. In addition the voluminous outputs of the many control center applications are hard for the operator to digest without some easy forms of visualization and alarming. Visualization of the grid outside a control center boundary is unavailable (or very primitive) today. This is a major drawback



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in the operation of large interconnected systems – consider that it takes about 100 balancing authorities and 10 reliability coordinators to monitor the Eastern Interconnection with none of them having any idea of what is going on in most of the system. The limited ability of knowing what is going on in the neighboring system has been a consistent element among the causes of large blackouts.

Innovative visualization methods developed by in the late nineties by PowerWorld and others have made their way into mainstream EMS visualization. However, the static 2D visualization may not be sufficient for the emerging requirements. In particular mechanism for handling multi-dimensional and multi-scale data are highly needed. The feasibility of integrating the state-of-the-art visualization concepts into EMS platforms needs to be continued.

Integration

The core network EMS applications are proprietary and were originally written in FORTRAN or C. Complex EMS system applications have been incrementally built around the core code using other languages and better structure. Integration and interoperability efforts have been driven by XML and SOA. However, indiscriminate use of CIM wrappers for legacy applications has the risk of fossilizing core applications. The transformation of the electricity industry will be unprecedented and massaging models and application so they can fit the legacy code may not be the optimal approach. Integration must be balanced with innovation objectives. We will study innovative architectures for application integration, which provide such balance.

Summary of Issues

The present communications infrastructure is inadequate for handling the increasing real time data transfers imposed by the PMUs at the transmission level and the new measurements at the distribution level. The requirements are stretched by the data rates at the transmission level and by the data volumes at the distribution level.

The present proprietary data structures at each control center are a major impediment to data transfers between the distribution and transmission levels, as well as between EMS in the same interconnection. This issue impacts the ability to seamlessly monitor, operate and control the interconnected power system and is the crux of this paper.

The present communication architecture and data structure of control centers forces all the computation to be done at the control center. The ability to distribute the computation over several control centers

would enhance the ability to seamlessly spread the applications horizontally over larger control regions (ultimately the whole interconnection) and vertically between transmission and distribution.

Visualization of the power grid is the most important tool available to the operators to monitor the grid but today is limited to the jurisdiction of the individual control center. The inability to seamlessly move data means that operators monitor their systems with blinders on, a condition that is flagged by every blackout report to be one of the root causes.

The seamless architecture and data management of control centers will allow the integration of applications across control centers. This can be across the interconnection (e.g. state estimation of the whole interconnection at PMU rate) or between transmission and distribution (e.g. coordinate distributed solar in one region with hydro or batteries in another region). Integration of applications over distributed computers will also impact the architecture.

Seamless Power System Analytics

Introduction

Basic and new power system computer applications are fundamental to the successful operation and planning of power systems. The current approach to power system analysis has developed over the last several decades in a piecemeal fashion where most applications are highly siloed running separately with their own databases, formats, system models, and user interfaces. Although some of the available tools have improved, many of the programs are built upon core technology and software architectures that were proposed decades ago, each developed individually, for its own unique purpose, often containing legacy code that implemented algorithms designed for sequential computing hardware. Most existing applications have their various components tightly coupled, non-separable, likely written in Fortran, a language today's young engineers rarely know. The internal code is not structured. In addition, external data interfaces are unwieldy, the user interface is weak, there is usually no centralized engine to house the numerical methods used in the applications, interoperability for applications is cumbersome, and deployment to high-performance computing platforms is difficult. Despite significant uncertainty in most power system analysis problems, codes are usually entirely deterministic. The result is that applications are difficult to use, updating or extending such software is very tedious (it is often easier to create new software completely), computational speed is below its potential, and results can be limited in applicability.

These limitations need to be overcome by state-of-the-art analytical tools that can support modernization of the electricity industry. New models and tools are required to handle emerging needs driven by increasing model size, renewable penetration, phasor measurement-based wide-area monitoring and control, and the need to share models, analyses, and results across a wide spectrum of organizations. Current and future computing requirements necessitate an integrated approach that builds upon state-of-the-art algorithms, hardware and modern day methods for data management across a shared environment.

We propose the development of seamless analytics for power systems, defined as follows:

- Seamless analytics is an organization of computing levels, each one comprised of individual components, such that each component at any level may interface with, use, or be used by any component at any other level, with minimal effort on the part of the human analyst. The levels are:
 - Applications: operational, operational planning, protection, long-term planning
 - Functions: numerical methods and basic linear algebra manipulations
 - Data: Equipment condition, DMS, customer, EMS, Market

The human analyst may simply use the applications and data, or s/he may also manipulate the applications using different functions and/or architectures.

A conceptualization of seamless analytics for power systems is provided in Figure 20, which includes the following: data (yellow, lower left corner), numerical methods (grey, bottom), applications (orange, middle), computing architecture (green, upper right corner), coordination system (blue, top), and human analyst (white, top left corner). The power systems seamless analytics engine is envisioned to operate efficiently on data to arrive at good decisions, as illustrated in Figure 21.

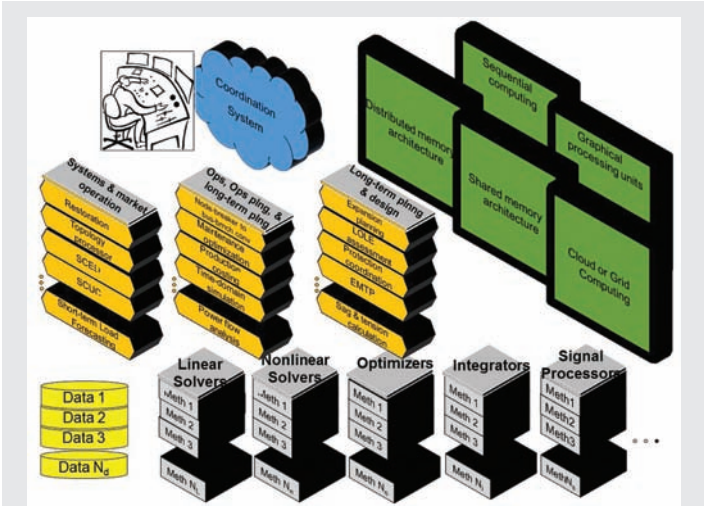


Figure 20 – Conceptualization of Seamless Analytics for Power Systems

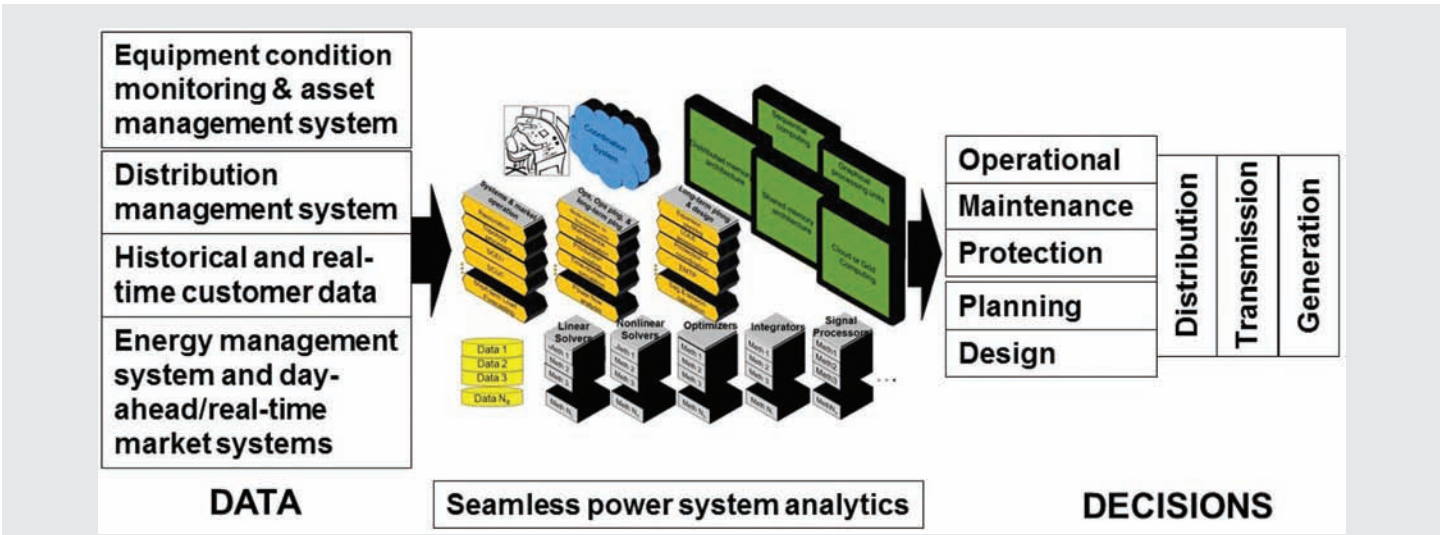


Figure 21 – Seamless Power System Analytics Functionality – Data to Decisions

Applications and Required Analytics

In this section, we summarize applications and corresponding analytical methods required.

Applications

Organizational groups within the electric power industry needing access to power system analytics (datasets and applications) include generation owners, load serving entities, transmission owners, co-ordination organizations (ISO/RTOs), and oversight organizations (NERC, FERC, state-level regulators). We recognize that manufacturers, vendors, consultants, and researchers also need access to power system analytics, but most of these needs are similar to those of industry; where unique needs arising for special R&D objectives exist, we assume they are addressed on a case-by-case basis. An identification and classification of power system analytic applications is provided in Table 1. The applications are divided into three areas: those used primarily in systems and market operations, those used primarily in long-term planning and design, and those used in both and/or in operations planning, corresponding roughly to temporal delineation by short, long, and mid-term time scales, respectively.

A general application which is useful across most of those identified in Table 1 is case processing, where many simulations are run and

results are processed in order to use the application to answer some particular question, e.g.: “What is the flow limit on a key interface to avoid violation of reliability criteria?”

In addition to the applications summarized in Table 1, there are a number of applications which are needed but not yet commercialized. Most of these applications are not deployed or are deployed only as research-grade software or early prototypes. These applications are listed below, grouped in appropriate categories. A description of each of these applications is provided in Appendix A.

1. Applications spanning operations and planning:
 - a. Bridging operations and planning models
 - b. Protection system modeling
 - c. Determining right-sized models
 - d. Distribution system needs (distributed resource forecasting and dynamic analysis)
 - e. System study tools to perform stochastic analysis in any time domain
2. Operations
 - a. Market applications
 - b. PMU-based monitoring and control

Table 1 – Classification of Analytic Applications by Organizations and Application Areas						
Application Area	Analytic Applications	Generation Owners	Load Serving Entities	Trans Owners/ Operators	Coordinators (BAs & ISO/ RTOs)	Oversight (NERC, FERC, State)
Systems and Market Operations	State Estimation					
	Alarm Processing					
	Load Forecasting (Short-Term/Mid-Term)					
	Wind/Solar Forecasting					
	Network Topology Builder & Processor					
	Restoration					
	Event Recreation					
	Switching Sequence Management					
	Interchange Scheduling					
	Fault Detection & Location					
	Switching Optimization					
	SCED					
	SCUC					

Table 1 – Classification of Analytic Applications by Organizations and Application Areas (continued)

Application Area	Analytic Applications	Generation Owners	Load Serving Entities	Trans Owners/ Operators	Coordinators (BAs & ISO/ RTOs)	Oversight (NERC, FERC, State)
Operations, Operations Planning, and Long-Term Planning	Steady-State Frequency Performance Eval					
	Reserve Management & Optimization					
	Power Flow Analysis					
	Static Security Assessment					
	Voltage Stability Analysis					
	Visualization & Geo-Info System GIS Layer					
	Transient & Oscillatory Time-Domain Sim					
	Load Modeling					
	Extended-Term Dynamic Analysis					
	Available Transmission Capacity					
	Production Costing					
	Hydro-Thermal Coordination					
	Outage Management/Scheduling					
	Maintenance Optimization					
	Node-Breaker & Bus-Branch Model Convrns					
	Unbalanced Three-Phase Power Flow					
	Volt/Var Optimization					
Long-Term Planning and Design	Generation Expansion Planning					
	Generation Siting					
	Load Forecasting (Long-Term)					
	Eigen-Analysis					
	Reliability Assessment					
	Short Circuit Analysis					
	Protection Coordination					
	EMPT					
	Arc Flash Analysis					
	Line Impedance Calculation					
	Line Ampacity Calculation					
	Line Sag & Tension Calculation					
	Cable Ampacity Calculation					
	Cable Sizing					

Table 1 – Classification of Analytic Applications by Organizations and Application Areas (continued)

Application Area	Analytic Applications	Generation Owners	Load Serving Entities	Trans Owners/ Operators	Coordinators (BAs & ISO/ RTOs)	Oversight (NERC, FERC, State)
Long-Term Planning and Design	Transformer MVA Sizing					
	Transformer Tap Optimization					
	Capacitor Placement					
	Motor Starting Analysis					
	Harmonic Analysis					

- c. Dynamic state estimator
 - d. Risk-based security assessment
 - e. Extended-term high consequence analysis
 - f. Look-ahead analytics
3. Operations planning
 - a. Frequency performance assessment
 - b. Short-term stochastic scheduling
 - c. Communication dependencies
4. Planning and design
 - a. Long-term load forecasting
 - b. Transmission and generation expansion planning
 - c. Transportation and energy system planning
 - d. Uncertainty modeling for long-term planning

Numerical Methods Comprising Each Analytic Applications

Each computing application is an integration of various basic numerical methods, including, for example, linear equations solvers, nonlinear equation solvers, numerical integrators, and optimizers. Each of these may be implemented using any of several algorithms; for example, linear solvers, perhaps the most common function within power system analysis applications, can be either a direct solver or an iterative solver, and there are various implementations of each. Likewise, numerical integration methods may be classified into explicit and implicit integrators, with multiple implementations of each. And there exist a range of optimization algorithms, even for a single type of mathematical program, e.g., linear programs, integer programs, nonlinear programs, and mixed integer programs. We summarize four of the most ubiquitous numerical methods in the following four subsections.

Linear Solvers

Linear solvers fall into 2 categories: the direct linear solvers and the iterative linear solvers. Direct linear solvers are more robust but memory intensive compared to iterative solvers. For very large problems involving in excess of a million equations, iterative solvers are the only solvers of choice due to memory limitations.

There are a number of algorithms available for both the direct and the iterative solvers. However not all algorithms are suitable for all applications. The choice of the method depends on the problem at hand and the numerical characteristics of the matrices involved. Some of the characteristics that impact the choice of the methods are diagonal dominance, numerical stability, symmetry, conditioning, and structure (e.g., banded or tridiagonal). Iterative solvers often require a good pre-conditioner for the method to converge especially for ill-conditioned matrices and non-symmetric problems like those found in transient stability analysis.

There are a number of state-of-the-art direct sparse linear solvers for unsymmetric matrices (typical of power systems) available with different algorithms and for hardware platforms, including those applicable for sequential computing (UMFPACK, SuperLU, KLU, HSL, and MA78), those useful for multithreaded computing (SuperLU, PARDISO, WSMP), and those useful for distributed computing (WSMP, MUMPS, SuperLU).

Choice of hardware also plays an important role in the selection of the linear solver algorithms. For example some algorithms are more amenable to parallelization than others. And even within the parallelization paradigm, some are more suitable to distributed computing and some for shared memory architecture. Most direct linear solvers need Basic Linear Algebra Subroutines (BLAS) libraries which are tuned for different architectures.



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Linear solvers fall into 2 categories namely the direct linear solver and the iterative linear solvers. Direct linear solvers are more robust but memory intensive compared to iterative solvers. For very large problems involving in excess of a million equations, iterative solvers are the only solvers of choice due to memory limitations.

Nonlinear Solvers

Newton methods and its variants are the methods of choice for solving nonlinear systems of equations. There are a number of different algorithms that fall under this broad category. Some examples are line search based Newton methods, trust region based Newton methods, gradient based Newton methods, and Broyden's methods.

Newton methods and its variants are the methods of choice in general because of their excellent quadratic convergence characteristics. However they need good initial estimate (especially for power flow to avoid divergence). Newton algorithm with global Line search (LSN) method should be used in the power system analytic applications to increase the robustness of the algorithm. Once the solution is within the solution region it switches to full Newton for quadratic convergence.

On promising method is the new hybrid Newton and Steepest Gradient (HSGN) based minimization algorithm to solve nonlinear equations which do not easily converge with Newton method alone due to poor initial guess or stiffness. The strategy in this algorithm is to first solve the nonlinear equations as a least square minimization problem. This gives a very good starting point for the Newton method for fast convergence. Similarly the trust region based Levenberg-Marquardt algorithm and the Line Search Newton methods can be combined to develop a hybrid trust region line search gradient based Newton Algorithm.

For problems with good convergence characteristics, decoupled Newton (DN) methods can be used where the variables are decoupled and solved separately and iterated to get the final converged solution.

Integrators

Integration methods are categorized as implicit or explicit methods, multi-step or one-step methods, variable time step or fixed time step methods. The choice of the integration method depends on the stability, accuracy, convergence characteristics, order, and stiffness (ability to take large time steps). Explicit integrators are available in most standard transient stability packages. Where implicit methods

have been implemented, trapezoidal methods and related variants have been most widely used.

To achieve high computational efficiency one likes to use variable time step methods. However one has to use higher order (2,3,4...) A-Stable implicit methods to take large time steps. Higher order means more computational burden at both the solution of non-linear system of equations and the solution of the linear system of equations.

However, when the system is in fast transient one has to take smaller time steps to capture the transients. In such situations explicit methods or lower order implicit methods are much faster. Therefore, variable-order-variable-time-step integration methods can achieve speedup especially for extended term simulations. The order and the time step of integration are chosen based on the previous integration steps and the truncation errors. Variable order variable coefficient BDF (Backward Differentiation Formula) and other methods are good methods for this approach.

Optimizers

A large number of optimization techniques are currently used in the industry today to serve the needs of various applications at various stages. A representative list of the applications with the corresponding methods is presented in Table 2.

Table 2 – Power System Optimization Applications

Analytic Applications	Optimization Method
SCED	Linear Programming
SCUC	Branch & Bound*, Lagrange Relaxation
Hydro-Thermal Coordination	Linear Programming, Branch & Bound
Outage Management/Scheduling	Branch & Bound*
Maintenance Optimization	Branch & Bound*
Volt/Var Optimization	Reduced Gradient, Newton, Penalty Function
Generation Expansion Planning	Dynamic Programming, Branch & Bound*
Transmission Planning	Linear Programming, Branch & Bound*
Switching Optimization	Branch & Bound*

* The power system engineering community often uses the term "mixed integer program" (MIP) to refer to the branch & bound algorithm or one of its variants (e.g., branch and cut). We view that MIP is a problem class rather than an algorithm.



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In the 1970s and 1980s, it was typical to include optimization code directly within the power system applications. Today, it is almost universal to use optimization solvers, such as any of those listed at NEOS Wiki [1], where input to the solvers is generally equation-oriented and generated by pre-processing code. IBM's CPLEX is a commonly used optimization solver for linear programs (LPs) and mixed integer programs (MIPs), which comprise the largest number of optimization problem types solved by the power industry.

Optimization in power system analytics is being driven by three issues: a) need to address optimization at various scales (e.g., reserve management), b) uncertainty due to resource variability, load variation and demand response, and c) the need to evolve from deterministic instantaneous optimization for real-time operations to stochastic dynamic scheduling. Seamless power system analytics will require the current optimization techniques to be enhanced and integrated carefully into the study tools.

Recently, Adaptive Dynamic Programming, which handles both dynamic and uncertain optimization problems, has emerged as a powerful method for solving a significant range of problems [2]. Efficient methods for handling stochastic programming methods have recently emerged and are likely to be of great interest for SCUC and various planning problems [3].

Decomposition methods, including Benders and Dantzig-Wolfe, have been used in research-grade power system applications before, although they have not been used heavily in commercial grade software. For optimization problems which can be decomposed into sub-problems (equivalently, if the problem constraint matrix has appropriate structure), they facilitate solution modularity and can also offer significant gains in computational efficiency. SCED, SCUC, and planning-focused optimization are generally of this type.

Existing Gaps and Challenges

Interoperability, Data Formats, and Component Models

Few power system analysis software applications today are interoperable, that is, they cannot easily be interfaced or ported. They cannot be easily used as part of other systems except as a component of the customized system on which it was built. Current software applications use inconsistent models and formats, contributing to the difficulty of migrating applications between platforms or to extend the analytical capabilities. There are a number of different formats for power system data used in studies. A significant portion of these

formats are proprietary and based on non-unified models. For instance, in the planning power flow arena there is a de-facto standard provided by PSSE RAW format. However, description of this format, and code to read and write it, are not directly available to non-PSSE users. The IEEE Common format is used to a lesser extent. The Common Information Model (CIM) represents an effort in the direction of unifying the power system network models. However most vendors have created translators to CIM rather than develop new CIM-native tools. In addition, CIM is not comprehensive for power system analysis, with many domains and areas not covered by the standard. Finally, the current Resource Description Framework (RDF) implementation of CIM, a metadata model for information exchange over the internet, has drawbacks such as unnecessarily increased model size, which inhibits the model exchange objective. Nonetheless, CIM is the most promising approach to achieving this available today. Unless another approach is embraced, a significant challenge will be expanding and completing CIM so that vendor-neutral standard data formats can be made available.

Human Interface

A significant portion of the applications used in the industry are still based on text-type result and command prompt interaction. They have not been updated with modern graphical user interface (GUI). They also do not provide a flexible mechanism to exchange outputs with other applications. Few applications provide easy and well-documented application programming interfaces (APIs) and automation interfaces. There are various graduations in terms of capabilities and usability which could be built into the human interface. Handling large input datasets and filtering bad data is essential. An ultimate objective would be to develop a master GUI that can manipulate and visualize results of all seamless applications across all time domains, providing the ability to both see the system and see into the system.

Analysis Initiation

Current applications require a steep learning curve for analysts to overcome, and even after mastering an application, significant effort is required to prepare cases, to import and export data, and to perform various manual actions. Such human effort should not be needed in order to initiate analysis. One characteristic of a seamless analytics engine is the ability of the user to concentrate on the analytics and not on the mechanics of running the software or the development of work-arounds in using the software for unique applications.



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Post-Processing

Analysis results are often data-intensive, stored in very large files. They must be post-processed in various ways using data mining methods, extracting knowledge contained in them to enable efficient human assimilation of that knowledge. A flexible suite of processing functions is needed, which can be easily accessed and used to process results of all applications.

Temporal Scales

Emerging power system analysis requires addressing behavior at temporal scales that have not been studied in the past. Examples are PMU, wind variability, sub-hour scheduling, and shorter-term forecasting. A significant portion of emerging business processes are concentrated in operations planning from a few minutes to several hours. Current power system planning and operations are almost completely separate from the point of view of models, formats and applications used. Therefore, a major barrier to seamless power system analytics is to break the temporal scale divisions so that power system applications provide solutions to analytical needs at expanded temporal scales.

Validation

An important need for power system analysis is validation of simulation results. PMUs and high-bandwidth communication channels create opportunities today. The seamless power system analytics function may be able to use make use of these opportunities to develop validation capabilities for power system analysis applications.

Encoded Intelligence for Selecting Software/Hardware Combination

Enhance computational speed via new algorithms and high-performance computing is a high priority for the seamless analytics engine. The vast majority of existing software is not multi-threaded and is not suited for parallel or cloud computing. Powerful but inexpensive computational resources are available today, such as dual or quad core computers, but these are not well-used or if used are not fully exploited. For a given computing function, the most effective algorithm is often dependent on the type of computing platform. There is need to enable fast identification of the optimal algorithm/hardware configuration to implement a particular computing function. An essential feature of the proposed seamless analytics will be the ability to suggest, in response to user-requested assessments (e.g., power flow) and user-specified characterizations of those assessments (e.g., speed, accuracy), appropriate selections of software and hardware to perform the assess-

ment. Designing, developing and encoding the intelligence to make this selection is a significant engineering challenge. The choice of software will be in terms of application and numerical algorithm for supporting the application. Summaries of representative applications and algorithms are provided in *Applications* and *Numerical Methods Comprising Each Analytic Applications*, respectively.

An Overarching Architecture

The vision described in this document of a seamless power system analytics capability, as illustrated in Figure 20, requires an overarching architecture. This architecture, once developed, should be considered the computational foundation for the entire industry. In this section, we provide an initial view to illustrate some possibilities; however, identifying options for this architecture will require significant additional research. There are various types of computing hardware available; a broad classification include sequential machines, multi-core shared memory machines, high-performance distributed memory machines, and GPUs (graphical processing units). The choice of software architecture will be influenced by the hardware architectures available.

Several developments in computing concepts and software frameworks present opportunities to develop a seamless, interoperable architecture for power system analytics, including layered models, service-oriented architectures (SOA), cloud computing, and Web 2.0. These software paradigms allow some merging of the traditional roles of the application user and the software developer. We describe the first two of these in what follows.

Layered Model

Figure 22 illustrates a layered model paradigm software system. The layered model allows us to abstract the functionality of the lower layers from the higher modeling and application layers. Figure 22 (on page 22) illustrates a computation layer, a solver or algorithm layer, a data layer and an application layer. The software frameworks existing in the industry can be applied at various layers providing an abstraction, which enables interoperability. We describe each layer in what follows.

- The computation layer consists of a computing framework, which can be single-processor, parallel, distributed, or cloud computing-based, and which drives computation hardware including possibly a network and multiple asynchronous nodes.
- The solver layer includes an analytics engine which selects and integrates one or more algorithm classes (e.g., linear solutions,

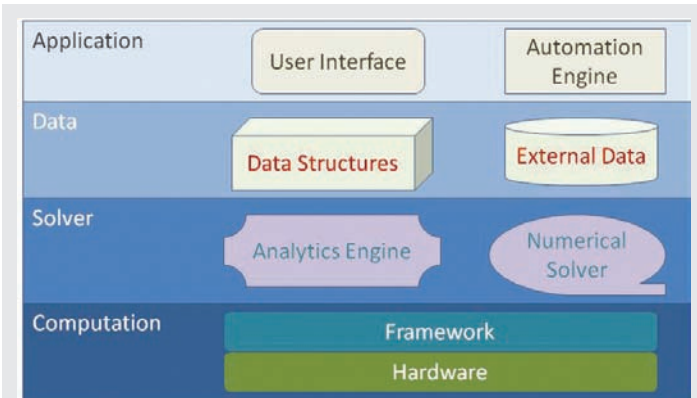


Figure 22 – Layered Model

nonlinear solutions, integrators, optimizers) to address a computing need, and within each algorithm class a specific numerical solver based on the attributes of the particular application.

- The data layer includes both the data structures internal to the application as well as external data connections and repositories. The external part may be part of interfaces to distributed algorithms.
- The application layer includes the user interface modules as well as automation engine which provide APIs, data interface, analytics interface, and process orchestration.

Achieving seamless power system analytics requires both existing and new applications to operate under a similar paradigm and to be equipped with the modules and functionality described in Figure 22. We describe a few attributes of the various layers:

1. If an existing application cannot use multi-processor power, the computational framework and possibly the numerical solver needs to be modified.
2. If a current tool does not provide advanced analytics, an analytics engine needs to be developed and integrated with the data structures, the numerical solver, and the computation framework.
3. If an arbitrary application, e.g. fault location requires, but cannot obtain data from external databases, a database connector and the corresponding data handling routines must be developed or enhanced.
4. Finally, if the functions of an application cannot be invoked by others in an easy manner, automation engines need to be coded to allow such interactions, and the corresponding process orchestrator needs to be developed.

SOA Model

An SOA-based collaborative decision model is illustrated in Figure 23 that would facilitate these kinds of needs. This model is built around three separate layers: decision processes, informa-

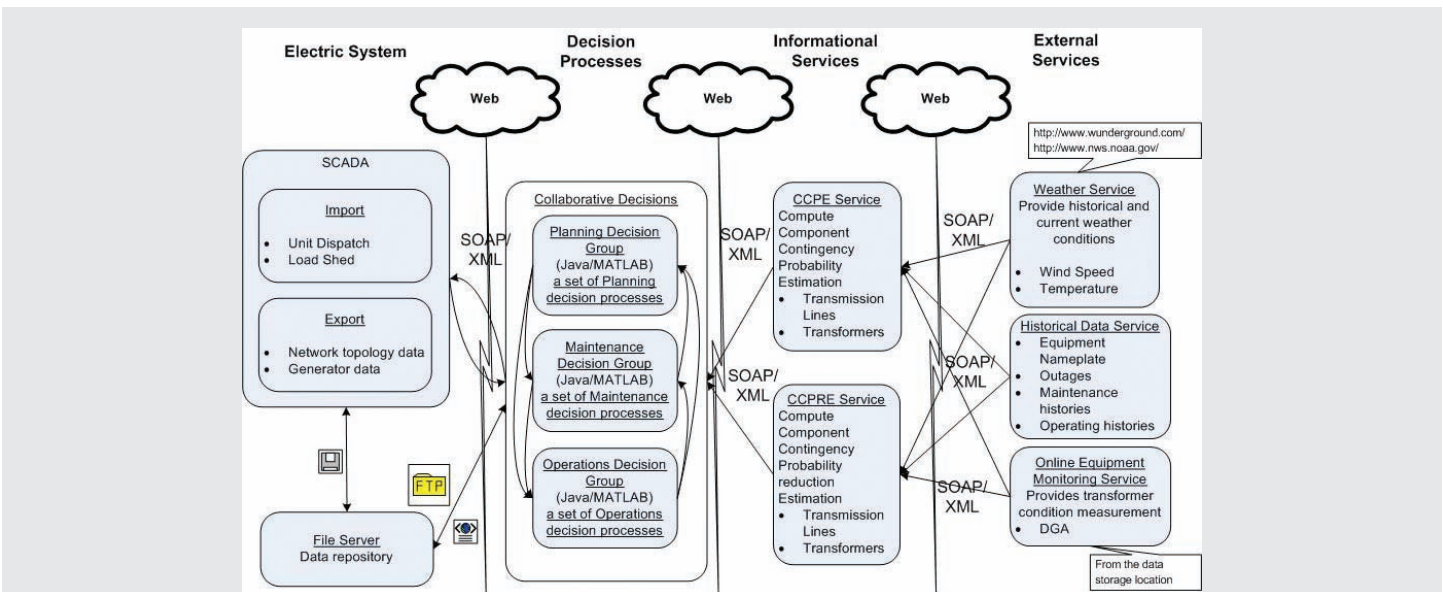


Figure 23 – SOA-Based Collaborative Decision Model



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tional services, and external services. We describe each of these in what follows.

- 1. External services:** These assimilate and aggregate raw data from technologically diverse information sources distributed across the grid. These raw data do not directly interface with the decision algorithms and require additional data transformation. These services include the *Weather Service* that provides wind speed and temperature, the *Historical Data Service* that warehouses historical data, and the *Online Monitoring Service* that provides online equipment condition measurements (e.g. transformer dissolved gas in oil analysis)
- 2. Informational services:** These transform data from external services into metrics that can directly interface with decision algorithms. Representative examples include the CCPE and CCPRE services which compute component contingency probability and component contingency probability reduction from maintenance, respectively, for use by the decision processes.
- 3. Decision processes:** These provide the central component of the decision making cycle, interacting with the OTS, informational services, and other decision processes to retrieve data for the decision algorithm, compute, and deliver decisions to the requesting entity. In this particular collaborative decision design, there are three major decision groups: planning, maintenance, and operations. Each decision group may have multiple sub decision processes. At the heart of each decision process is a master optimization routine which calls slave decision routines in a multi-level nested architecture. The strengths of SOA are utilized to support the communication needs of this architecture. Benders decomposition is used to support the algorithmic needs of this architecture.

All the components in Figure 23 are built as Web services implemented using Java 2 Enterprise Edition Web services and the JAVA programming language. They are then deployed on Apache Tomcat Web server with Apache Axis2 Web service container. The Web services interact with each other in the form of standard XML-based SOAP messages.

Barriers

Financial Commitment

It is likely that the time to build a complete system is in the range of a decade. After identifying a complete and realistic cost estimate, cost-benefit case, and high-level project schedule, obtaining buy-in from funding organizations to pursue the project will be challenging. It may be useful to pursue participation in stages: government, then utilities, and then vendors.

Institutional Resistance

In developing seamless power system analytics, there are legacy codes for power system analysis which will have to be enhanced or possibly re-developed. This will be costly, and consideration of the necessary expenditures will result in resistance in favor of less costly alternatives, including the option of continuing to use the same legacy codes. Vendors will not make substantive changes in their software systems without significant commitment of funds from customers and/or government. Another source of resistance results from the fact that most legacy codes have been heavily used, and as a result, they are trusted. Re-developed codes will not initially elicit that same degree of trust, and as a result, users may migrate slowly, and knowledge of this effect will inhibit investment in the project.

Prioritizing Tool Development

With limited financial resources, re-development of existing functionality and initial development of new functionality cannot all be done simultaneously. The community will need to go through a process of prioritizing tool development. This process will need to be carefully developed and managed, as any given prioritization will benefit some organizations more than others. A particular issue here will be the existence of some tools that have a relatively small user-base due to the specialty of their function but are essential for some organizations, Hydro-thermal coordination programs are an example of such a tool.

Deployment of Software Engineering Technologies

The development of seamless power system analytics will require advanced expertise in software engineering. Power system engineers are typically not exposed during their education to software engineering methods, although some pick up some related skills on the job. Designing, deploying, and maintaining systems based on state-of-the-art software engineering may necessitate a financial and educational commitment within the power system engineering community.



Capabilities of the System Analyst – Applications and Numerical Methods

We conceive of the *system analyst* as an individual who utilizes applications to generate information on which various power system decisions are based but who also performs high-level development by integrating various numerical algorithms with appropriate hardware to accomplish the purpose at hand. The typical power system engineer today has background sufficient to select and use applications; however, many of them do not have background sufficient to select appropriate numerical algorithms or integrate them with appropriate hardware. Therefore, seamless power system analytics may have functionality that is underused unless skills of the system analyst are sufficiently enhanced through education and training.

Testing and Certifying Code Base

The code base will need periodic testing and certification. The difficulty of this task increases with the complexity of functionality offered by the code. It will be economically justifiable to develop and embed self-testing facilities within the software system.

Critical Infrastructure Protection Standards

A desirable strength of the seamless power system analytics is an ability to provide analytic services across the organizational enterprise. However, the broader is its accessibility, the more likely it is exposed to violation of critical infrastructure protection standards (CIPS). There may be a need to balance accessibility and CIPS compliance.

Prioritization of Next Steps

Priority should be placed on accomplishing the following objectives.

1. Obtain consensus regarding
 - a. New applications and analysis needs
 - b. Existing gaps and challenges
 - c. Barriers
2. Identify possible options regarding overarching architecture
3. Initiate work on a R&D roadmap, a cost schedule, and development of a cost/benefit case.

Conclusions

Power system and electricity market operation, maintenance, planning, and design have for decades heavily depended on computational tools. There are now a large number of such tools, most of

which operate largely stand-alone, interfacing only with the single input database designed for the particular tool. This makes the job of the power system analyst very difficult, and as a result, there is an opportunity to enhance the efficiency and effectiveness of the power system analyst. Doing so would translate into significant economic benefits, as the price of electric energy heavily depends on the decisions made by the power system analyst.

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Setting-Less Protection Method

Introduction

The current state of art in protective relaying is quite advanced. Yet gaps exist in the sense that (a) we do not have reliable protection schemes for a number of protection problems, such as downed conductors, high impedance faults, and (b) for systems and components that do not comply to the general principle of large separation between abnormal and normal conditions the protection schemes tend to be complex with areas of compromised performance, leading to issues such as load encroachment, false tripping, etc. In this paper we will assess the current state of art and will identify some of the common gaps/shortcomings in component and system protection. We will also examine the present state of protection technology, as defined with the present day high-end numerical relays that use microprocessors of equal performance as those utilized in high end personal computers. We finally would like to suggest approaches towards a more simplified and expectedly setting-less protection. The goal of the suggestions is to stimulate discussion and create a research plan towards achieving simplified but fully reliable protection schemes that cover all protection problems. The proposals, suggestions, ideas will be examined and evaluated by several criteria: (a) feasibility, (b) dependability, (c) security, (d) reliability, and (e) speed of protection. The specific approaches may be (but not limited to):



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adaptive relaying, component state based protection, substation state based protection, pattern recognition-based protection, etc. A brief description of the proposed approaches is as follows:

Adaptive Relaying: The basic idea is to monitor the condition of the system and change the settings of the protective relays accordingly. Adaptive relaying has been the focus of many attempts for the last 30 years (since the introduction of numerical relays). There are many challenges to adaptive relaying that stem from the necessity to obtain information about changing fault capabilities as generating units come on or go out of service, etc. Recent technological advances, especially GPS-synchronized measurements and fast communications can overcome some of the adaptive relaying challenges. It is also important to note that the traditional approach to adaptive relaying is to adjust the relay settings in real time. The new technologies may enable autonomous relay setting tuning and coordination. We propose to evaluate the impact of new technologies on adaptive relaying. While this relaying relies on automatically adjustable settings it does address a new concept that eliminates settings.

Component State Estimation Approach. A very promising approach towards setting-less protective relays is by use of dynamic state estimation. The basic approach is to use measurements from numerical relays (of device voltage, currents, and other specific quantities, for example taps for a transformer, etc.) to estimate the state of the component in real time. The dynamic state estimation enables the monitoring of the “health of the device under protection”. The health of the component deteriorates only when the component experiences a fault. Preliminary results of this approach are given in [5] and background material is provided in [3], [4]. Potential this approach can lead to true setting-less protection schemes. This approach will be carefully evaluated and protection schemes for transformers, generators, lines, reactors, capacitors, etc. will be discussed.

Substation Based Protection. This approach is an extension of the “component state estimation approach” and it is described in reference [1]. The idea here is to apply dynamic state estimation to the entire substation and then protection action will be taken on the basis of the state of the entire substation in real time. This approach requires that all IEDs in substation are reporting to the same computer/relay. These schemes are presently feasible. Issues of speed by which the substation state estimation can respond will be addressed. The feasibility, advantages and disadvantages will be examined for typical substation configurations. This approach can also lead to true setting-less protection schemes.

Pattern recognition-based protection. This protection method uses heuristic methods such as neural networks and fuzzy logic to recognize changes in the network signal features that characterize a fault. The traditional concept of setting is substituted with a pattern space that is defined through extensive modeling and simulation. Initial studies have shown significant improvements of such schemes in comparison to the existing ones [7-9]. Additional schemes are also developed based on real-time calculation of waveform properties as a discriminant for the existence of the fault. In this case the pattern of interest is the particular waveform property [10-11].

Finally, the problem of *system (wide area) protection* will be addressed. This is probably the most complex protection problem. We will investigate the concepts presented earlier (component state estimation and substation based protection) and their extension to system protection problems. Reference [2] presents the use of GPS-synchronized measurements and substation state estimation for the purpose of developing an out of step protection scheme based on energy concepts. The approach described in reference [2] is a setting-less protection scheme for out of step protection. We will expand on this idea for other system protection problems, such as voltage swings, etc.

The approaches described above will be evaluated with the following criteria: (a) feasibility, (b) dependability, (c) security, (d) reliability, and (e) speed of protection.

Review of Present State of Art

Since the early days of electric power systems it was recognized that protection is essential for the operation and safeguarding of the power system assets.

History of Protection

Protective relaying was initially developed to protect individual components. As interconnections grew, system problems and system protection issues arose. In recent decades we see the development of system protection approaches. Component and system protection are distinct and they will be discussed separately.

Component Protection: Initially, electromechanical relays were introduced at the early stages of the electric power industry. Electromechanical relays are electromechanical systems that are designed to perform a logic function based on specific inputs of voltages and/or currents. This technology started with the very simple plunger type relay and evolved into highly sophisticated systems that performed



complex logical operations, for example the modified mho relay is a system that monitors the impedance of the system as “seen” at a specific point in the system and will act whenever the impedance moves into a pre-specified region. In the early years of the electric power industry, the inverse time-delay overcurrent relay was developed based on the induction disk (Westinghouse) or the induction cup (GE). The overcurrent protection function is one of the main protection functions provided in practically all protections schemes. Over the years the electromechanical relays developed into sophisticated analog logic devices with great selectivity and operational reliability. The development of differential protection and distance protection were two major milestones. The introduction of the transistor in the late 40s resulted in solid state devices that can perform logic operations. In the 60s we see efforts to develop solid state relays with the same functionality as the electromechanical relays. Solid state relays were short lived as the first effort to develop digital (numerical relays) was introduced in the late sixties with the first digital relay developed in 1970 (G. Rockefeller, Eric Udren) that formulated the approach for digital relays. These efforts were refined when the microprocessor was introduced in the early 80s and led to the development of the microprocessor based relay (numerical relay). The first commercial available numerical relay appeared in the early eighties as Westinghouse and GE developed prototypes under the EPRI funding of the WESPAC project for transmission all-digital substation, and the first microprocessor relay for distribution system applications was introduced in 1984 (Schweitzer). Since then, the numerical relay increased its domination to the point that today has almost completely displaced electromechanical and solid state relays. The numerical relays today, by and large, they simply mimic the logics that developed for the electromechanical relays with much more flexible manner. Because numerical relays can pack many protection functions in one box, numerical relays are multi-functional. The increased functionality has resulted in very complex schemes that many times lead to inconsistencies and possibility of improper protection actions.

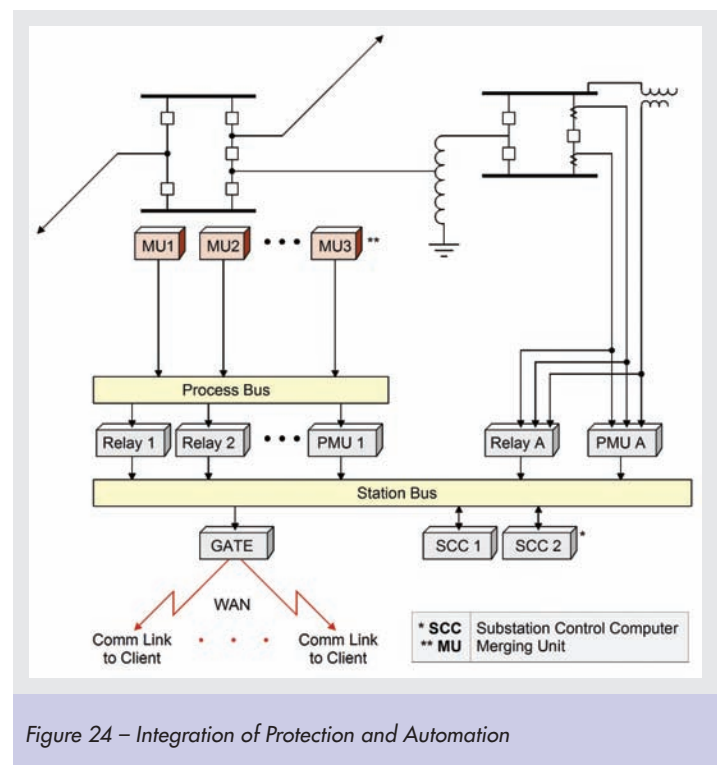
Differential protection is one of the easiest, secure and reliable scheme. For geographically extended components, differential protection schemes involve a number of approximations to account for the fact that information from the geographically remote locations must be brought to one location and compared. A breakthrough occurred in 1992 when Macrodyne (Jay Murphy) introduced the first GPS-synchronized device that he named PMU (Phasor Measurement Unit). This technology enables true differential protection

schemes of geographically extended components and presently we see the development of such systems. The evolution of fast communications has enabled this approach.

System Protection: the first system protection concept was developed for the out of step protection of generating units and it was based on impedance relays. Subsequently wide area measurements were used for system wide monitoring and protection. Special protection schemes typically use pre-computed scenarios and arming the system to identify these scenarios and respond. This approach can be classified as a “pattern recognition” approach. The introduction of GPS synchronized measurements created more possibilities for better implementation of wide area monitoring and protection. Yet, the approach remains the same and it is limited by time latencies required to transfer the data to a central location, process the data and compare them to pre-computed disturbance patterns.

Integration of Protection and Automation

The numerical relay enabled increased automation. Figure 24 below shows two major approaches as evolved in the past decade. To the right of the figure, the approach of connecting numerical relays to the instrument transformers and control circuits on one side and to a station bus on the other side for easy communications and manag-





ing relay settings is shown. To the left of the figure, the introduction of the merging units and the process bus is shown. These arrangements lead to the capability to use the relays as an integral part of the SCADA system and eliminates the need for Remote Terminal Units in the usual sense. The relays or the station bus provides the functionality of the Remote Terminal Units. It also leads to the integration of protection and control.

The above state of recent technological advances (PMU capability, merging units, process bus, station bus, interoperability) have not been accompanied with commensurate advances on the protection coordination. The settings of protective devices still utilize the same principles of many decades ago. These principles rely on distinct separations and characteristics between “fault conditions” and “normal and tolerable conditions.” Even for the classical power system without renewables and a plethora of power electronic interfaced components, the separation and identification of “fault conditions” and “normal and tolerable conditions” is in many circumstances difficult, for example, short lines, weak/strong feeds, high impedance faults, etc. In the presence of renewables with power electronic interfaces, these issues multiply. The end result is that it becomes extremely difficult to develop a secure, reliable, dependable, speedy, safe and low cost protection system based on the conventional principles.

Summary of State of Art

Presently numerical relays provide multiple functionality, communications, self-diagnostics, ability to integrate other functions such as SCADA, and ability to be integrated with automated closed loop control systems. Standards are being developed to enable the integration of relays into closed loop control schemes - in particular the IEC 61850 standard provides a great tool to ensure interoperability and to coordinate intelligence among relays, such as to inform one relay to lock out or inhibit reclosing, etc. In general, protection functions require settings. There are many tools that facilitate computations required to decide the settings of the various protective functions. However, there are no analytical tools to calculate and validate optimum settings for dependable and reliable relay functions. As a result selecting protective relaying settings require human input and decisions - in general a complex procedure for typical substations.

For distribution circuits, the present state of art is based on the assumption of radial operation. It is expected in the near future that the distribution system will become active with substantial distrib-

uted generation and resources. This expectation will necessitate revisiting the common approaches to distribution protection.

Finally, despite the advanced state of art of numerical relays, certain protection problems are still evading a reliable and secure protection scheme. Some of these will be discussed next.

Gaps in Protection Approaches

While component and system protection has reached phenomenal sophistication, certain gaps still remain. The gaps can be classified into two categories: (a) protection problems for which a satisfactory solution does not exist, such as downed conductors, or high impedance faults, and (b) protection problems for which present protection schemes leave “compromised protection areas”. The latter lead many times to false operations, such as load encroachment, sympathetic tripping, etc. Some examples of gaps in protection are discussed in Appendix A.

One major challenge of problems in the second category exists in systems with resources that interfaced with power electronics, such as wind farms, PV farms, distributed generation, etc. The main characteristic of these systems are that their fault current capability is limited by the power electronics creating a disparity between the grid side and the resource side. What complicates matters more is the fact that some of the power electronics have complex control functions that the protection system must recognize and distinguish between abnormal operating conditions and legitimate complex response to a disturbance. Another complexity is the fact that for better protection schemes, it is necessary to monitor the DC side of these systems as well and incorporate the conditions of the DC side into the protection schemes. With respect to this issue there is a hardware gap as present day numerical relays have been designed to monitor AC quantities only. For these systems one needs numerical relays with capability to measure DC quantities.

Below we provide additional comments on specific issues and challenges.

Wind Farm Protection: Wind farms are generating plants with non-conventional generation (induction machines with power electronics, for example type 3 and type 4) that present the following characteristics: (a) the fault current contributions from the power grid may be quite high but the fault current contribution from the wind generator is comparable to the load current. While present protection schemes and numerical relay capability is tweaked to



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develop a reasonable overall protection scheme for wind farms, the solutions are complex and lack full reliability (security, dependability and speed). Are there better ways to protect these systems? The increased complexity from mandated controls, such as zero voltage ride-through capability further makes the protection problem a challenge.

Distribution System with Distributed Generation: These systems present the same challenges as wind farms with the additional complexity of mixing protection systems that were designed on the basis of radial power flow to a system with bidirectional power flow. Some present standards take the easy way out by suggesting disconnection of distributed resources in case of disturbances and faults. There must be a better way if we want to increase the economic value of distributed resources.

PV Farm Protection: PV farms exhibit the same protection challenges as wind farms. It is important to note that while wind farm protection and operational issues are under serious consideration and research activity, for PV farms the activity is very low and under the radar screen. At the same time there is substantial development of utility size PV farm systems and larger activity of residential PV activity. It is important that the protection and operation of these systems be further researched and improved.

Down Conductor Protection: This problem has been with the industry for a long time with various attempts to solve the downed conductor protection system. While many schemes have been developed, none of the schemes can provide definitive protection against downed conductors.

Summary of Gaps and Challenges

Despite the advanced status of numerical relays there are gaps in protection and settings may lead to compromise solutions. NERC keeps track of power system disturbances and the causes of power system disturbances. Year after year, the number one root cause of power system disturbances is listed as relaying issues. This is a definite indication that protective relaying gaps exists and the challenges is to eliminate these gaps. Some of the gaps are methodological as we do not have a technically reliable and secure way to protect against certain problems as it is discussed in Appendix A. Some of the gaps and challenges are tools and manpower related. For example we lack test beds to try new ideas, lack of tools to assess the optimality of system relaying settings, depletion of experienced protective relaying engineers. Finally there are gaps due

to the introduction of new technologies and specifically wind and PV farms. These systems are characterized with different models, i.e. they do not have the same characteristics as legacy equipment and therefore new approaches for their protection are required. A related issue is the gap that is being generated by the fact that distribution systems are becoming increasingly bidirectional power flow systems with many generating resources along the distribution system.

The challenges in closing these gaps are mostly institutional. First one has to deal with the risk averse nature of the protection and control community. There is resistance to accept different paradigms and models and to trust these models. The mindset of keeping the relay as a dedicated device with its own inputs (measurements) must change to allow multiple inputs and more information for the purpose of addressing the protection requirements in a more reliable and secure manner. Finally the challenge is to develop solutions to the existing gaps that will allow an orderly transition—not wholesale changes.

Emerging Technologies

Present day numerical relays use high end microprocessors for implementing multiple functions of protection. For example a transformer protection relay may include all the typical protection functions that traditionally used with electromechanical relays, i.e. differential, over-current, V/Hz function, etc. Since these functions work independently, even if they are implemented on the same relay, they suffer from the same limitations as the usual single relay/single function approach. Each function must be set separately but the settings must be coordinated with other protective devices. The coordinated settings are typically selected so that can satisfy requirements that many times are conflicting and therefore a compromise must be selected. For this reason, most of the time the settings represent a compromise and occasionally may exist possible fault conditions that may lead to an undesirable relay response.

It should be understood that numerical relays have provided many more options that have improved the above procedure. At the same time the additional options have created increased complexity and increased possibilities of human errors, while the basic nature of the problem of selecting settings has remained the same: the settings must be selected to satisfy criteria that many times are conflicting. The natural question is whether any new technologies and trends can favorably affect the protection process.



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There are technologies that can enable better, integrated approach to the overall protection. Some of these technologies are (technology is in flux with many developments still to occur):

1. Merging units/separation of data acquisition and data processing/protection
2. GPS synchronized measurements (PMUs)
3. Data Concentrator (PDCs, switches, etc.)
4. Smarter sensors
5. Integrated (power system/relay) analysis programs that enable faster and more reliable assessment of settings
6. Data validation/state extraction
7. Other

It is difficult to assess the full impact of these technologies on the future of protection. One thing is clear though: while there is much technology development in hardware and the capabilities of hardware, the development of new approaches to fully utilize the new capabilities is lagging. This is the classical problem of “hardware being ahead of software.” This will come with realistic assessment of the new technologies and bold experimentation of new approaches and the eventual emergence of successful approaches.

One can contemplate what approaches can be enabled by emerging technologies. It is clear that the approach of individual protective functions based on a small number of measurements (for example three currents and three voltages) makes the protection function not fully reliable since the relay tries to identify the conditions from limited information and then take control action with an algorithm that is based on limited information. This is a fundamental limitation of the present approach to protective relaying and the technology of numerical relays have not change it. The introduction of the process bus offers the obvious possibility of bringing many measurements (as a matter of fact all the measurements) to the process bus. Now a relay can be connected to the process bus and it may have access to all the measurements available in the substation. It should be noted that even if the process bus is today a reality, the relays attached to the process bus access only a limited amount of information, i.e. three voltages and currents, in other words the design of the relay that can be connected to the process bus has not changed from the traditional design that uses analog inputs to the relay. We can project that

relays connected to a process bus can be designed to connect to a larger number of channels with very little add on cost since these connections are “digital”. Then it will be necessary to develop new algorithms for protective relaying logic that will depend on all available information. This will almost guarantee a dramatic improvement on the reliability of the protective scheme. The discussed scenario will require hardware changes and software development. It has the capability to eliminate one of the fundamental limitations of the usual protective relaying approach of individual relaying functions operating on limited information. The role of GPS synchronized measurements for such an approach will be critical. As measurements are collected at different locations of the substation with independent data acquisition system and then the information is brought to the process bus it will be necessary to time-align these data before they will be used by the relays. GPS synchronized measurements and standards such as C37.118 and IEC 61850 will provide standardized means for time-aligning the data. Another issue that may have to be addressed is the time latencies generated by this approach. We believe that these issues can be addressed and successfully solved.

There may be many more approaches that take full advantage of the new capabilities enabled with new technologies. The above discussion is for the purpose of stimulating discussion on how new technologies can improve protective relaying approaches.

The Need for New Thinking and New Approaches

There is agreement that (a) present protection schemes are complex and (b) coordination of protection schemes are based on principles introduced many decades ago. Complexity increases the possibility of human error and the coordination principles used today develop settings that many times represent a compromise among conflicting factors. The end result is that the industry is experiencing more unwanted relay responses than are desired. NERC statistics on causes of disturbances list protective relaying as the top root cause.

It is also recognized that new but commercially available technology could enable new approaches to protection. We provide some thoughts towards new approaches that will automate and simplify protection. The goal of the comments below is to stimulate discussion towards developing new ideas and new approaches for simple and fully reliable protection schemes.

Adaptive Protection

The basic idea of adaptive protection is based on the recognition that as system status changes (for example a generator is tripped and the new fault levels will change), so the best settings of protective relays change. It makes sense to monitor the system conditions and when changes occur to change the settings of the protective relays accordingly. Adaptive relaying has been the focus of many attempts for the last 30 years (since the introduction of numerical relays). A summary of the attempts towards adaptive relaying is captured in Figure 25, on the following page. The picture shows the need to monitor the status not only of the component protected by the relay but also the system so that the real time model of the system can be extracted. The real time model needed by the adaptive relaying scheme needs to provide information on breaker status (open/close), short circuit capability of system, etc. This type of real time model can be only provided with advanced state estimation techniques that are very fast. From this information, the relay settings are properly adjusted, for example the breaker failure scheme must be adjusted to reflect the present status of breaker status, etc.

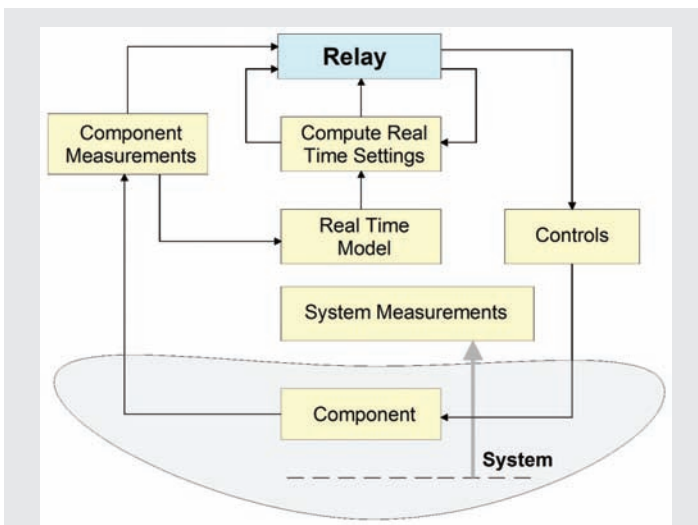


Figure 25 – Summary of the attempts towards adaptive relaying

There are many challenges to adaptive relaying that stem from the necessity to obtain information about changing fault capabilities as generating units come on or go out of service, etc. Recent technological advances, especially GPS-synchronized measurements and fast communications can overcome some of the adaptive relaying challenges. It is also important to note that the traditional approach

to adaptive relaying is to adjust the relay settings in real time. Questions that need to be raised are:

- (a) Can new technologies enable autonomous relay setting tuning and coordination in an adaptive scheme?
- (b) What is the impact of new technologies on adaptive relaying? For example new faster state estimation methods, new faster wide area monitoring technologies, etc.
- (c) The traditional approach to adaptive relaying relies on automatically adjustable settings using traditional principles for selecting settings. Is there any new ideas and approaches for a better approach to adaptive relaying that may eliminate settings altogether?

It is clear that adaptive relaying requires a complex algorithmic approach and reliable communications. Therefore it is realistic to say that the challenges for this approach are to cope with the complexity and the need for reliable communications.

Pattern Recognition-Based Relaying

The concept of using pattern recognition is to employ well known heuristic methods that look at input signals and based on particular signal properties (features) captured through techniques such as neural network or fuzzy logic, classify such properties into domains that differentiate between faulted states and normal states, and also allow classification of fault types and other fault properties such as location, fault resistance, etc. An example of such an approach using neural networks is shown in Figure 26. Further details are given in references [9] and [10].

In Figure 26, going from left hand lower corner clockwise, one can note the conceptual steps involved in this process, which is

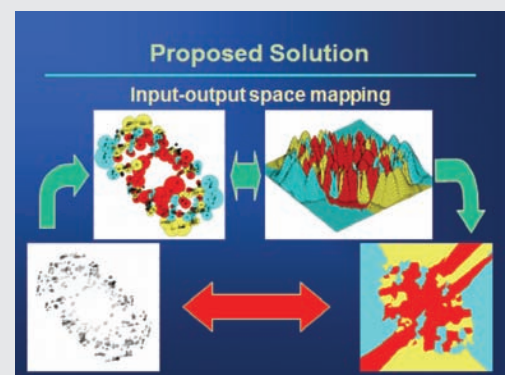


Figure 26 – Pattern Recognition-Based Relaying

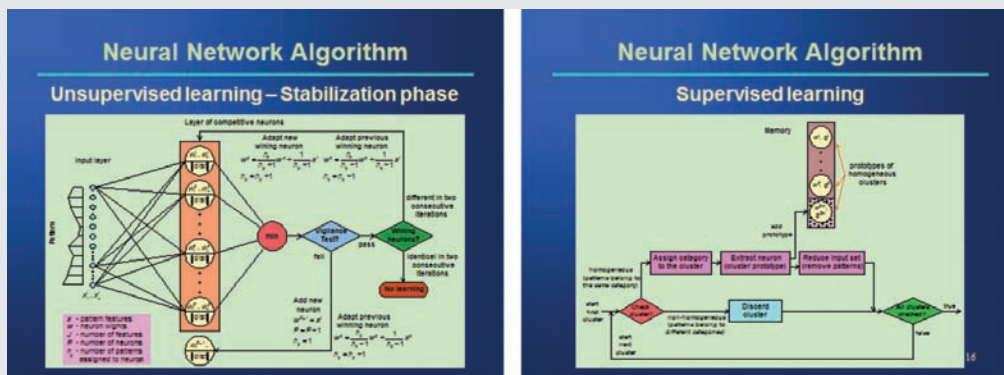


Figure 27 – Pattern Recognition-Based Relaying—Learning

actually reduced to input-output space mapping using neural networks:

Step1: Mapping from signal samples to the space of patterns in the n-dimensional pattern space. This process is further explained in the left hand side of Figure 27. Samples are taken through a neural network, and based on learning principles, all the samples are mapped in certain spheres that are well defined by the Euclidian distance that each sample set creates with respect to a centroid of the sphere. The sphere radius is varied until all “similar” patterns fall into non-overlapping spheres. Such spheres represent patterns of waveforms that designate a type of fault or designate a normal state. This process is often called unsupervised learning since the classification of patterns is strictly done based on their features with no knowledge what they actually represent.

Step2: Classification of patterns into fault or no-fault clusters. This process is shown in the right hand Figure 27. Through additional signals samples that are now known to belong to a given type of fault or disturbance, all the clusters are classified into the ones that designate various category of the input event. Once this process is completed, the pattern space capable of classifying future signal patterns is created. This process is typically called supervised learning since the knowledge about the input signals is used to designate or classify the patterns the outcome of this process is shown in the proposed solution as the second graph with colored clusters corresponding to certain types of events.

Neural Network Training. This process is required to further tune the clusters and verify that sufficient separation between clusters representing different types of events is achieved. The outcome of the training process is a tuned set of clusters as shown in upper left hand

side of Figure 28. This set of clusters, however, still has areas in the n-dimensional space that are not covered by the clusters. This creates a problem for the set of signals representing an event in the case when such set falls in an area that does not allow for cluster designation. This case is shown in the upper right hand side of Figure 28.

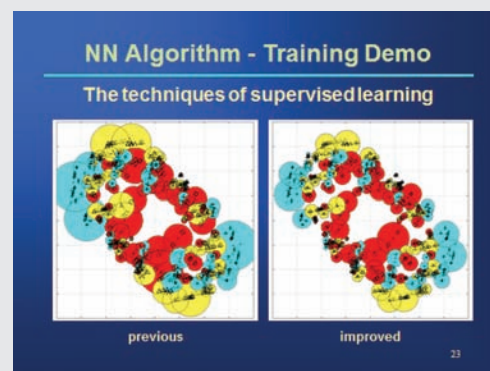


Figure 28 – NN Algorithm - Training Demo

Step3: Fuzzyfication of NN outputs. In this case a k-nearest method enhanced with fuzzy variables is used to fill in the gaps in the pattern space. Filling in the gaps is actually done by associating the new patterns that fall in the space between the clusters to a given cluster based on the l-nearest principle. This process is shown in the left hand side of Figure 29. The right hand side of Figure 29 shows the outcome: a “continuous pattern space. In this case, the regions for category classification are extended beyond the clusters and any new pattern can be recognized as a particular type of event. This way the last two steps in the input-output space mapping shown at the beginning are accomplished.

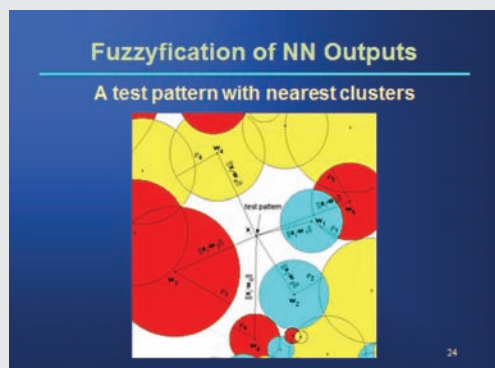


Figure 29 – Fuzzyfication of NN Outputs

This example in Figure 27 through Figure 29 illustrate how differentiation between different events, including fault types, can be made using just the input patterns and no settings at all.

State Estimation Approach for Component Protection

For secure and reliable protection of power components such as a generator, line, transformer, etc. a new approach has emerged based on component health dynamic monitoring. The proposed method uses dynamic state estimation [4-7], based on the dynamic model of the component, which accurately reflects the nonlinear characteristics of the component as well as the loading and thermal state of the component.

The approach is briefly illustrated in the Figure 30. The method requires a monitoring system of the component under protection

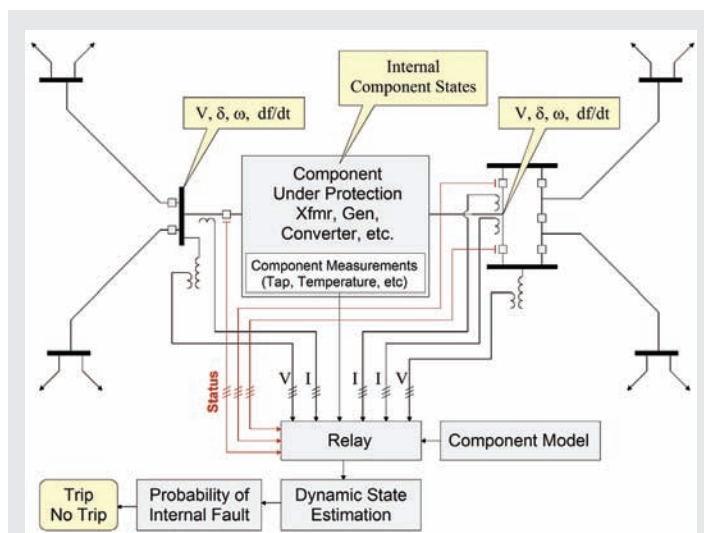


Figure 30 – State Estimation Approach for Component Protection Overview

that continuously measures terminal data (such as the terminal voltage magnitude and angle, the frequency, and the rate of frequency change) and component status data (such as tap setting (if transformer) and temperature). The dynamic state estimation processes these measurement data with the dynamic model of the component yielding the operating conditions of the component.

The operating condition can be compared to the operating limits of the component to develop the protection action. The logic for the protection action is illustrated in the Figure 31.

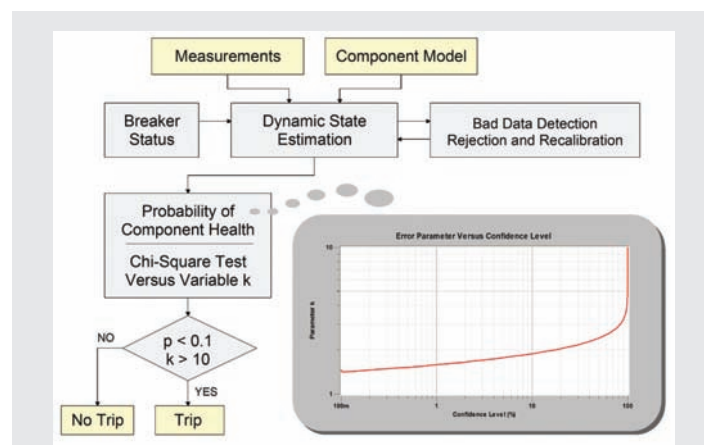


Figure 31 – State Estimation Approach for Component Protection Logic

This approach faces some challenges which can be overcome with present technology. A partial list of the challenges is given below:

1. Ability to perform the dynamic state estimation in real time
2. Initialization issues
3. Communications in case of a geographically extended component (i.e. lines)
4. New modeling approaches for components - connects well with the topic of modeling
5. Requirement for GPS synchronized measurements in case of multiple independent data acquisition systems.
6. Other

The modeling issue is fundamental in this approach. For success the model must be high fidelity so that the component state estimator will reliably determine the operating status (health) of the component. For example consider a transformer during energ-

zation. The transformer will experience high in-rush current that represent a tolerable operating condition and therefore no relay action should occur. The component state estimator should be able to “track” the in-rush current and determine that they represent a tolerable operating condition. This requires a transformer model that accurately models saturation and in-rush current in the transformer. We can foresee the possibility that a high fidelity model used for protective relaying can be used as the main depository of the model which can provide the appropriate model for other applications. For example the EMS applications, a positive sequence model can be computed from the high fidelity model and send to the EMS data base. The advantage of this approach will be that the EMS model will come from a field validated model (the utilization of the model by the relay in real time provide the validation of the model). This overall approach is shown in Figure 32. Since protection is ubiquitous, it makes economic sense to use relays for distributed model data base that provides the capability of perpetual model validation.

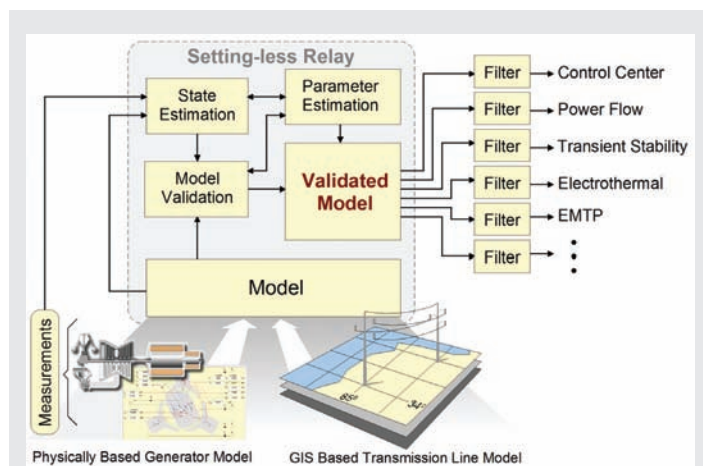


Figure 32 – Conceptual Setting-less Relay Model

State Estimation Approach for System Protection

By far the most complex protection problem exists at the system level. System level protection issues may involve events that develop in a very short time, such as pole slipping in a generator, or events that develop in relatively long times, such as voltage stability/collapse. The events can be numerous. Can new technology provide better and simpler solutions to system problems? What will be the principles and the underlying approaches?

The present day approach to out of step protection leads to excessive wear and tear of equipment as in general the out of step condition is recognized only after it has occurred resulting in delays in tripping the unstable unit and excessive exposure to high currents and abnormal conditions. Is there an approach that can be predictive and simple (not requiring settings for determining the condition?). A predictive approach is described in [2]. Can this approach be successfully implemented using present and future technology?

The present day special protection systems are based on “pattern recognition” approaches. The creation of the patterns requires extensive simulations of the system. They also require wide area measurements which turn generate time latencies and complicate the analytics and the protection logic. Is there a better approach that will not need the pre-computation of patterns? The key for an advanced approach will be improvements in wide area measurements and fast communication of the system status to a central location. For discussion reference, Figure 33 shows the typical configuration of special protection systems.

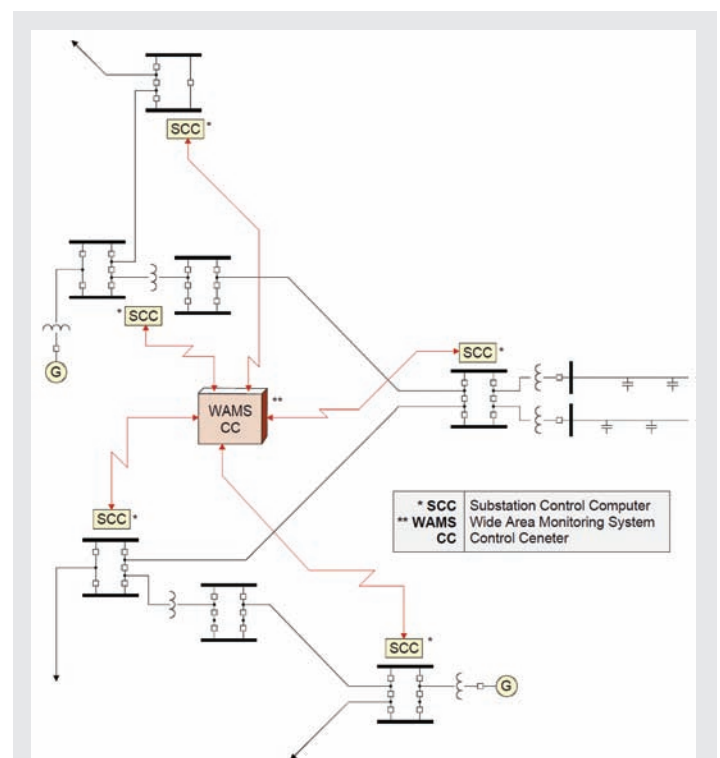


Figure 33 – Special Protection Systems Example

A fundamental issue is the collection of the actual operating conditions (dynamics) of the system at the central location where the system protection “relay” will reside. One can analyze the constituent parts of the general configuration and determine what will be need for a new reliable system protection scheme. One idea for discussion may be the use of local dynamic state estimators (distributed dynamic state estimators) at the substation level and transmitting the substation dynamic states to the location of the system “relay” via fast communications. This approach will provide the dynamic system state to the system relay in the minimum possible time latency. System protection algorithms must be developed that will take advantage of this approach. Potentially, this approach can be direct and reliable in the sense that the protective relaying algorithm will be based on the dynamic state of the system.

Summary of State Estimation Approaches

The technology is ready today to use dynamic state estimation for protection. Of course challenges exists and it will take research activities to achieve the goal of taking protection decision on the basis of reliable and secure data from the dynamic state estimator. The advantage of state estimation approaches to protection is that it enables true setting-less protection schemes. The protection logic acts on the basis of the operating condition and health of a zone (component) or the system. The protection logic simply compares the condition to the operating limits of the component or the system. We believe it is feasible to develop and demonstrate setting-less zone protection (it is a low hanging fruit!!!). It also has the side benefit of providing a distributed model data base with perpetual validation.

The state estimation based protection approach represents a new paradigm that moves away from the traditional approach of mimicking the operation of electromechanical relays to the concept of monitoring the health and operating characteristics of components and systems as it is conceptually shown in Figure 34.

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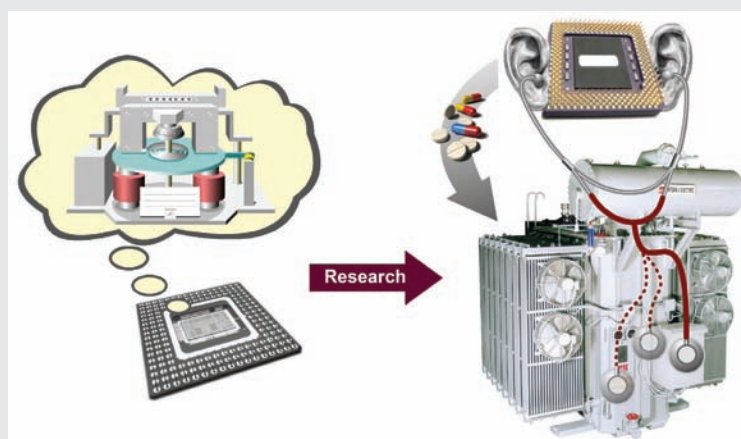


Figure 34 – State Estimation Approach for Component Protection Overview



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Appendix A: Description of New Analytic Applications

This appendix describes new analytic applications that are needed in the electric power industry.

Applications Spanning Operations and Planning

Converting Between Bus-Branch and Node-Breaker Models

The models used within planning are normally developed independent of the models used within the energy management system (EMS) of operations. Whereas the planning model is bus-branch, the EMS models are node-breaker or are at least developed from a node-breaker model through the topology processor. The ability to freely transfer back and forth between bus-branch models and node-

breaker models would provide benefits to both operational and planning analyses. The node-breaker model is especially important if protection systems are modeled.

Protection System Modeling

Many power system analysis applications in planning and operations do not model, or do not model very well protection systems. This often results in significant misinterpretation of analysis results. To capture the effect of protection within power system operations and planning analysis software, models for each type of relay will need to be developed so that it can generically interface with power system simulation software.

Determining Right-Sized Models

Many analyses today are performed using models of inappropriate size, either too large or too small, because of the difficulty in reducing or expanding an existing model to the right size. Key to almost all modeling needs is a first step assessment of the right model sized and a second step development of that model.

Distribution System Needs

Emerging distribution system needs are driven by the consumer and its responsiveness to control signals, electric vehicle interactions, and distribution-connected storage and resources. To facilitate this, a great deal of new control and communication will be needed, and its design and implementation will be challenging. In this subsection, we focus on the analytic needs of addressing these issues [1].

Key analytical tools that should be made available include the traditional ones of power flow, fault current analysis and protective relay coordination, fault detection and location, reliability assessment, power quality evaluation, and load forecasting. Of these, the interconnection of new types of loads and resources will motivate significant refinement and extension of fault current analysis and protective relay coordination. New tools that will be necessary for distribution system analysis include distributed resource forecasting, dynamic analysis. All tools will need to be extended to allow for these new types of loads and resources.

System Study Tools to Perform Stochastic Analysis in Any Time Domain

There exists uncertainty in analyses performed in operations, operations planning, and long-term planning for which analysis is



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significantly strengthened when those uncertainties are addressed. We have identified in subsequent subsections (operations, operations planning, and long-term planning and design) applications which are needed in the associated time from that require handling of uncertainty. These applications are (a) risk-based security assessment (operations); (b) short-term stochastic scheduling (operations planning); (c) uncertainty in planning (long-term planning). There is a need for a high level “uncertainty assessment module” which can be applied to perform stochastic analysis in any time frame.

Operations

Market Applications

Today's electricity markets depend heavily on use of two computational tools: the security constrained economic dispatch (SCED) for the real-time market, and the security-constrained unit commitment (SCUC) for the day-ahead market. Although these two tools are relatively mature, there are a number of further developments necessary. Reference [2] summarizes many of these needs, among which some of the more significant ones are:

- Modeling of uncertainty
- Modeling of sub-hour optimization in SCUC
- Detailed modeling of emerging reserve requirements
- Modeling combined-cycle generators
- Modeling dispatchable load
- Modeling flexibility in “soft” resource limits (related to risk-based security assessment, below)
- Including AC power flow representation in SCUC
- Modeling reactive power pricing
- Modeling flexible AC Transmission System (FACTS) devices

PMU-Based Monitoring and Control

There is great interest today in using phasor measurements to monitor power system modal behavior. The extension to control will place greater emphasis on analysis speed. Signal processing methods are essential elements of the software necessary to support this functionality. This is a very wide and deep field which has matured in application areas which do not heavily overlap with power system

engineering, and there are many signal processing methods which have not yet been explored for power system applications.

Dynamic State Estimator

Availability of GPS synchronized measurements at substations makes it possible to extend monitoring to much shorter time scales. A dynamic state estimator would involve dynamic models of generators, loads, controllers, etc., not currently included in power system estimation. Polynomial model identification can be used to build the models and unspecified or suspect device or controller parameters. Auto-regressive time domain model-based algorithms with PMU data inputs can be used to derive the required dynamic state and parametric estimation.

Risk-Based Security Assessment

The process of optimizing economics while managing risk associated with contingencies has been codified in the security constrained optimal power flow (SCOPF). This deterministic approach treats all selected contingencies in the same way: post-contingency violations activate binding constraints that prevent the violation, and contingencies resulting in no post-contingency violation activate no binding constraints and are therefore of no influence on the solution. The SCOPF approach suffers from a fundamental weakness in that system security is not quantified. Although its solutions are guaranteed to satisfy the imposed rules, those solutions may vary considerably in terms of actual system risk level. A method of managing real-time system security has been developed, and an industry prototype is being implemented.

Extended-Term High Consequence Analysis

Analysis of cascading outages which have occurred in the past shows that a large percentage of them were initiated by very low probability events that caused the power system to subsequently deteriorate over periods of one to several hours. The 2003 Northeast US Blackout was of this sort. The operational paradigm in use today has no functionality to address such low probability high-consequence events. There is need, therefore, to develop new functionality for on-line applications which we refer to as high-speed extended-term time-domain simulator (HSET-TDS). Such functionality would provide fast simulation of events for extended time periods up to several hours in order to capture the relatively slow degradation that is characteristic of some high-consequence scenarios. Development of HSET-TDS requires a re-evaluation of the basic components of time-domain simulation software, as illustrated in Figure A-1.

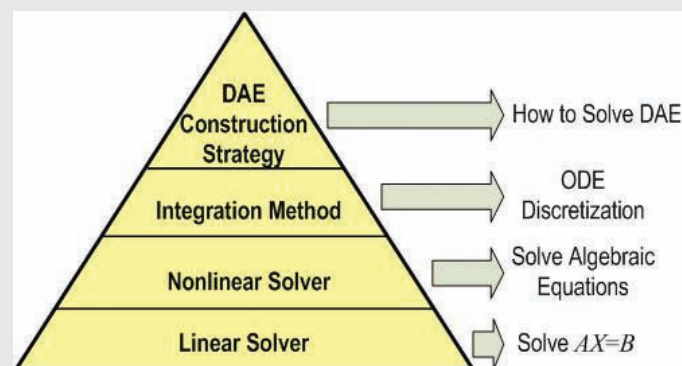


Figure A1– Basic Components of Time-Domain Simulation Software

Modeling extensions, relative to traditional time-domain simulation, would necessarily include load and VG ramping, AGC, and good protection system models, in order to appropriately capture cascading events.

Look-Ahead Analytics

Today's security assessment is generally performed on the last state estimation result, which means that assessment is always done for a past condition rather than a future one. Significant benefit can be gained from performing look-ahead analysis for 15 minutes ahead, 1 hour ahead, and 4 hours ahead. To accomplish this, it is necessary to integrate the latest state estimation, day-ahead SCUC results, and forecasts of load, wind, and solar at the appropriate interval. We recognize that many ISOs have similar functionality in the form of the reliability assessment commitment (RAC). This functionality needs to be further developed to facilitate comprehensive security assessment for overloads, voltage, voltage stability, frequency performance, and oscillatory behavior.

Operations Planning

Frequency Performance Assessment

The increase in penetration of variable generation (VG) technologies (solar and wind) across the nation has resulted in deterioration in control performance standards. This observation is based on CPS1 and CPS2 measurements reported by ISOs to NERC. This degradation can be mitigated through deployment of fast-ramping resources (generation, storage, demand), by controlling the VG, or by increasing control areas size. The ability to create a least-cost portfolio of mitigation measures requires a-priori assessment via software capable

of simulating the effects of such portfolios. Standard time-domain simulation software typically does not model AGC and so is not appropriate for this task. Operator-training simulators typically model at the appropriate level, but are unwieldy for this purpose due to the fact that their intended function is training. New software is needed that will be efficiently available to the system analyst.

Short-Term Stochastic Scheduling

Variable generation increases variability as well as uncertainty. Increased variability can be addressed by generation portfolios with higher ramping capabilities. For a given decision horizon (time between when the decision must be made and when it becomes effective), increased uncertainty requires unit commitment decisions which perform well under the increased range of possible conditions, i.e., the decisions must be more robust. This is particularly important for 4 to 48 hour-ahead unit commitment. Over the past 10 years, there has been significant maturation in methods to perform optimization under uncertainty, principally the methods referred to as stochastic optimization and robust optimization. Stochastic optimization identifies solutions which are optimal under a range of uncertainties, given the ability to take recourse for a given decision-future sequence. Robust optimization identifies solutions which are optimal and robust subject to a particular set of parameters which may vary within a certain range of conditions. More recent improvements have also added the ability to robust optimization methods to take recourse for a given decision-future space (continuous). These methods are applicable to power system problems in planning as well.

Communication Dependencies

The power system is increasingly dependent on communication. It is therefore of interest to consider to what extent should traditional power system contingency assessment include communication failures. Most of the research on smart grid assumes a reliable and dependable communication network providing adequate bandwidth and latency support all the time. However, the need of a combined communications/power simulator has been already identified [3,4,5]. Reference [6] proposes a co-simulation method for power and communication systems using existing power system software (such as PSLE, Modelica's SPOT) and communication network (such as NS2 or OPNET) simulators. Such co-simulators have the limitation that they do not translate all triggered events in the power system domain to the network domain and can work only with periodic events whose schedule is known beforehand [7].



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Researchers have also attempted to use IEEE HLA architecture to coordinate among different power, communications network, and control system simulators. But, this coordination is inefficient when simulating complicated scenarios due to overhead and amount of time and resources needed to make individual simulators compatible with HLA. The mutual interactions of power and communication networks are yet to be analyzed in detail.

In addition, NS2 and OPNET are network layer simulators, which assume a physical layer with consistent throughput and latency characteristics, omitting important aspects of physical layer design and operation. For example, a fiber optic or dedicated microwave link may be modeled as a communication system with consistent throughput and latency. Yet future grids would be built with a variety of communication technologies depending on the application. These networks cannot be used for most of the functionalities defined for smart grid due to their cost, deployment time, scalability and unsuitability for applications in transmission and distribution. A thorough understanding of what to expect for communication links with various characteristics is important in planning how a network can meet power system requirements. Simulations to test various communication links and their feasibility are essential.

Planning and Design

Long-Term Load Forecasting

Deployment of distributed energy resources (DER) will have a major effect on the ability to perform accurate long-term forecasting of the load the utility-scale generation has to meet. To address this issue, it will be critical to integrate the forecasting of load accounting for growth in demand response, energy efficiency, and distributed generation (DG).

Transmission and Generation Expansion Planning

It is expected that investment in transmission and generation will significantly increase over the next 10-15 years, and so planning functions take on a higher level of importance than they have in the recent past. Traditional planning approaches seek to find the least-cost way to expand the system while satisfying reliability constraints during the most stressed conditions. Although this paradigm will remain of interest, a new market-based transmission planning model is needed which finds expansion plans that maximize the economic benefits provided by new line additions. This will require planning

optimization tools which simultaneously (or at least iteratively) optimize generation expansion plans and transmission expansion plans. By iterating between generation planning and transmission planning results, a robust transmission investment plan can be designed which is best under most or all of the generation expansion futures. Doing so at the level of the ISO (regional) is a highly computational problem.

Another key need for transmission planning stems from the fact that the redistribution of generation occurring as a result of renewable growth causes significant change in power flow patterns. As a result, the existing transmission system configuration, designed for a mainly fossil-based generation distribution, is usually sub-optimal for a renewable-based generation distribution. Yet, it is not reasonable to completely redesign the transmission system. Therefore one would like to identify reconfigurations that could take place to strengthen the system for its new purpose, maximizing the system security level subject to a constraint on cost and possible right-of-way.

Key to the above two expansion planning problems is the ability to integrate equipment locational information with wind and solar resources. Geographical information systems (GIS) will play an important role to this end.

Transportation and Energy System Planning

Planning has always been done at the local or regional level and only for the electric system. Yet the advent of growth in low-GHG generation is causing a significant shift in generation location. This has implications in terms of the geographical level at which planning is done and the number of infrastructure sectors which should be included in the planning. Efforts are already ongoing to perform planning at the interconnection level and it may be that such efforts should be expanded to the national level. The shift to low-GHG resources will also have dramatic effects on the transportation systems used for fossil fuels, e.g., rail and petroleum, and enabling their inclusion in planning tools will be important. Finally, it is clear that transportation systems will become more and more dependent on electric energy, especially for highway passenger travel. These changes require that electric systems planning be done together with transportation systems planning.

Uncertainty Modeling for Long-Term Planning

Developing investment plans for long-term decision horizons requires extensive uncertainty modeling. Such modeling may be



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divided into two classes that can be called high- and low-frequency uncertainties. The former occur repeatedly and can be captured by fitting probability functions to historical data. Examples of these include uncertainties in fuel prices and component outages. The latter uncertainties do not occur repeatedly; therefore, their statistical behavior cannot be derived from historical data, but they may have great impact. Such uncertainties include, for example, dramatic shifts in weather and/or load forecasts, major policy changes, technological leaps, or extreme events (catastrophic contingencies). Low-frequency uncertainties become more important as planning horizons extend.

There is strong emphasis today by long-term planners on decision horizons that reach up to 20 years into the future, and it is infrequent that developers commit to constructing new facilities on the basis of needs that extend beyond this time frame. This is understandable because building significantly ahead of need can add expense due to the increased uncertainty of the longer time frame and the difficulty in convincing regulators to place economic burdens on current ratepayers for benefits enjoyed by future ratepayers. However, most of the investments have long lifetimes, some exceeding 50 and even 60 years. In addition, climate effects of GHG emissions are cumulative over multiple decades, so that response to GHG reductions are gradual and require long-term aggregation of measures to achieve them. Taking a view of needs beyond the typical 20-year decision horizon of current planning cycles need not require that today's investment decisions address what is built 50 years into the future but rather, that today's investment decisions fit into a 50- or even 100-year long-term plan, periodically adjusted to account for new information as it becomes available. Doing so will require addressing technical challenges associated with the necessary software tools.

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Appendix B: Protection Gaps

This appendix provides examples of protection issues for which we do not have a reliable and secure method.

Example 1: Transformer Protection Against Faults Near the Neutral. Faults near the neutral of a transformer cannot be detected with present day relays. Figure B1 shows this type of fault. When the fault is near the neutral, the voltages and currents at the terminals if the transformer may look almost normal.

Example 2: Successfully Cleared Transmission Faults Create Over-currents in Distribution Circuit Relays Due to FIDVR Phenomena (Increased Current Due to Load Dynamics). Such an event is shown in Figure B2 on page 40. Note the higher currents in the distribution feeder after the fault is cleared. These elevated currents may trip

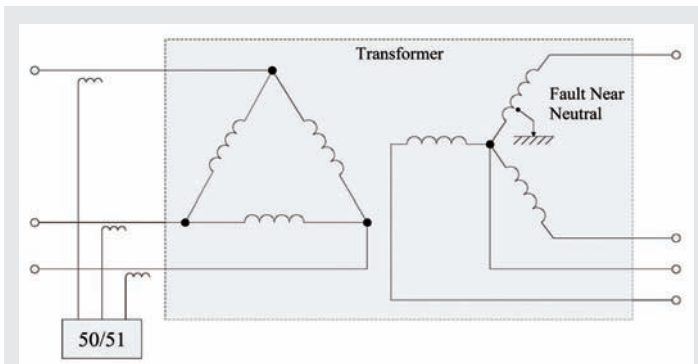


Figure B1 – Transformer Fault Near Neutral

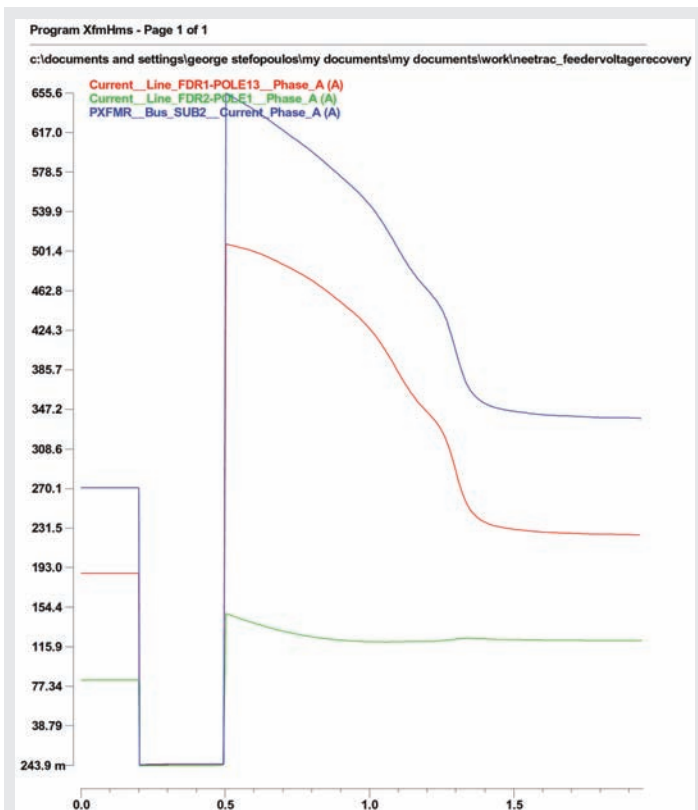


Figure B2 – Fault Induced Delayed Voltage Recovery

the distribution circuit on time-overcurrent. These phenomenon has been observed and it is expected that its frequency will increase.

Example 3: Present State-of-the-Art in Out Of Step Relaying is Based on Impedance Tracing, Timers and Blinders. This means when the relay asserts the out of step condition the unit has already slipped a pole. If breaker opens at the time the assertion is made (at

that time the phase of the unit with respect to the system may be at near 180 degrees) the risk of breaker restrike exists as the transient recovery voltage may reach four times the peak value of the normal voltage. Thus unit disconnection must be delayed to avoid breaker overstresses. This leads to longer times of high currents and the possibility of equipment damage. Out of Step Protection via Impedance Relays and Blinders is shown in Figure B3.

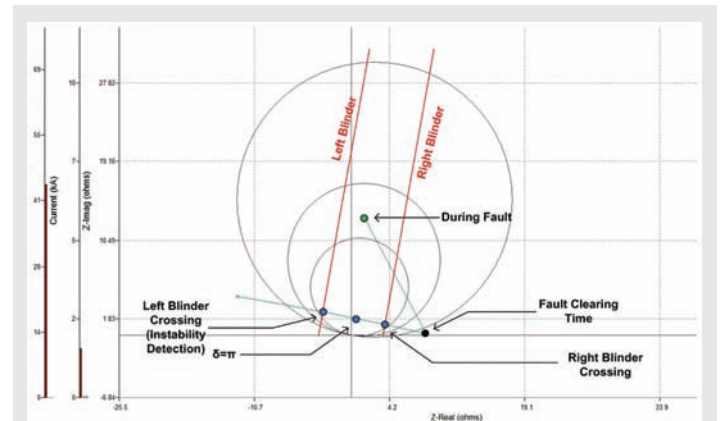


Figure B3 – Out of Step Protection via Impedance Relays and Blinders

Example 4: Another Existing Gap in Protection Exists in the Area of High Impedance Faults in Distribution Systems. Figure B4 illustrates the problem. Reliable relays for detecting this type of fault do not exist today (there are devices that may detect this condition in specific cases but not with the reliability required for this problem). As a result of our inability to detect this conditions, there are many fatalities annually.

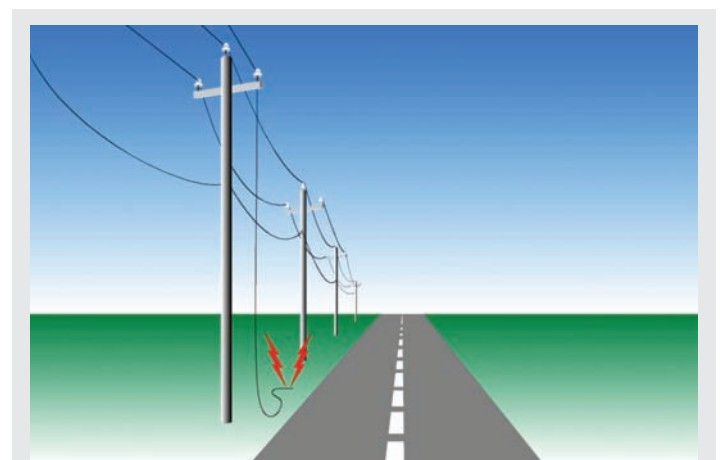


Figure B4 – High Impedance Faults in Distribution Systems

Appendix C: Synchronized Sampling Based Fault Location

An important function of protective relays that enables better protection decisions is the identification of fault location. Presently, this function is inherent (with approximate methods) in distance relays and also available off-line with more sophisticated computational algorithms. It will be important to include more sophisticated fault locating algorithms in the real time computations of relays. In any case this section describes advanced fault locating algorithms which can become part of the real time relay functions.

The fault locating function has two components: (a) verify the occurrence of the fault, and (b) estimate the location of the fault. They are very important because the fault location can confirm whether a fault has indeed occurred on the line. If used on-line, it can also serve as a relay verification tool for a back-up fault detection algorithm. When the fault is precisely located, one should know which breakers are responsible to clear that fault, enabling selective operation. Both the dependability and security of protection system operation will be improved by incorporating a precise fault location function.

Algorithm Description

Synchronized sampling based fault location algorithm uses raw samples of voltage and current data synchronously taken from two ends of the transmission line [1]. This can be achieved using Global Positioning Satellite (GPS) receivers, which generate the time reference for data acquisition equipment. It has two types of applications dealing with the short line lumped model and long line distributed model, which is shown in Figure C1.

The algorithm is derived by solving the classic transmission line differential equations [1,2]. Short line algorithm and long line algorithm are derived using lumped RL line parameters and distributed RLC line parameters respectively. The principle of this algorithm is demonstrated with the transmission line shown in Figure C2. The voltage and current at the faulted point can be represented by both sending end data and receiving end data using linear relationship because the homogenous parameter line is separated by the fault point. If there is no fault on the line, the fault location cannot be found because there are multiple solutions in that case. Different algorithms use different techniques to find the fault point [3,4].

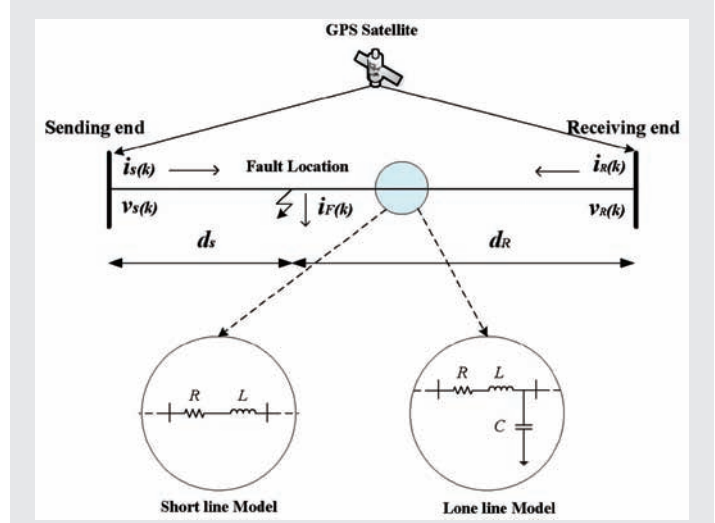


Figure C1 – Synchronized Sampling Based Fault Location

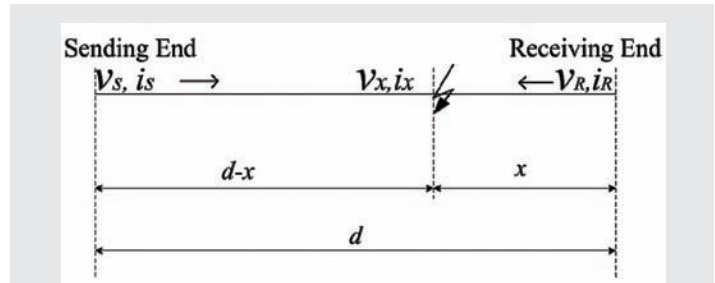


Figure C2 – A Faulted Transmission Line

Short Line Model: For short line, which is usually shorter than 50 miles, the fault location can be calculated directly using minimum square estimate method, as follows [3]:

$$x = \frac{- \sum_{m=a,b,c} \sum_{k=1}^N A_m(k) B_m(k)}{\sum_{m=a,b,c} \sum_{k=1}^N B_m^2(k)}$$

where:

$$A_m(k) = v_{\hat{a}}(k) - v_{\hat{b}}(k) - d \sum_{p=a,b,c} \left[\left(r_p + \frac{l_p}{\Delta t} \right) i_{\hat{p}}(k) - \frac{l_p}{\Delta t} i_{\hat{p}}(k-1) \right] \quad m = a, b, c$$

$$B_m(k) = \sum_{p=a,b,c} \left\{ \left(r_p + \frac{l_p}{\Delta t} \right) [i_{\hat{p}}(k) + i_{\hat{R}}(k)] - \frac{l_p}{\Delta t} [i_{\hat{p}}(k-1) + i_{\hat{R}}(k-1)] \right\} \quad m = a, b, c$$

where \$k\$ is the sample point, \$\Delta t\$ is sample period, subscripts \$S, R\$ stand for the values from sending end and receiving end of the line.

Long Line Model: For long transmission line model, we can only build the voltage and current profiles along the line using revised Bergeron's equation [2]:

$$v_{j,k} = \frac{1}{2} [v_{j-1,k-1} + v_{j-1,k+1}] + \frac{Z_c}{2} [i_{j-1,k-1} + i_{j-1,k+1}] - \frac{R\Delta x}{4} [i_{j-1,k-1} + i_{j-1,k+1}] - \frac{R\Delta x}{2} i_{j,k}$$

$$i_{j,k} = \frac{1}{2Z_c} [v_{j-1,k-1} - v_{j-1,k+1}] + \frac{1}{2} [i_{j-1,k-1} + i_{j-1,k+1}] + \frac{R\Delta x}{4Z_c} [i_{j-1,k-1} - i_{j-1,k+1}]$$

Where $\Delta x = \Delta t / \sqrt{lc}$ is the distance that the wave travels with a sampling period Δt ; $Z_c = \sqrt{l/c}$ is the surge impedance. Subscript “j” is the position of the discretized point of the line and “k” is the sample point.

The final location is obtained by an indirect method, as shown in Figure C3.

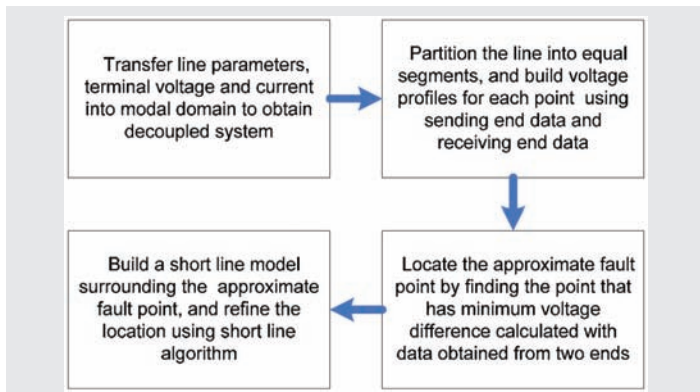


Figure C3 – Steps for Long Line Fault Location Algorithm

The accuracy of both algorithms is dependent on accuracy of data sampling synchronization, sampling rate and correctness of line model parameters.

Implementation of synchronized sampling based fault location: The flowchart for implementing synchronized sampling based fault location is shown in Figure C4. The data window used for calculation is one cycle, and the data window is moving forward with selected time step Δt . The fault is detected if the criterion equation is fulfilled for a successive cycle. Then the post-fault values are used for fault classification and fault location, using the methods demonstrated in the previous papers [1-3].

Compared to the fault location algorithms that use one end data, SSFL makes no assumptions about fault condition and system

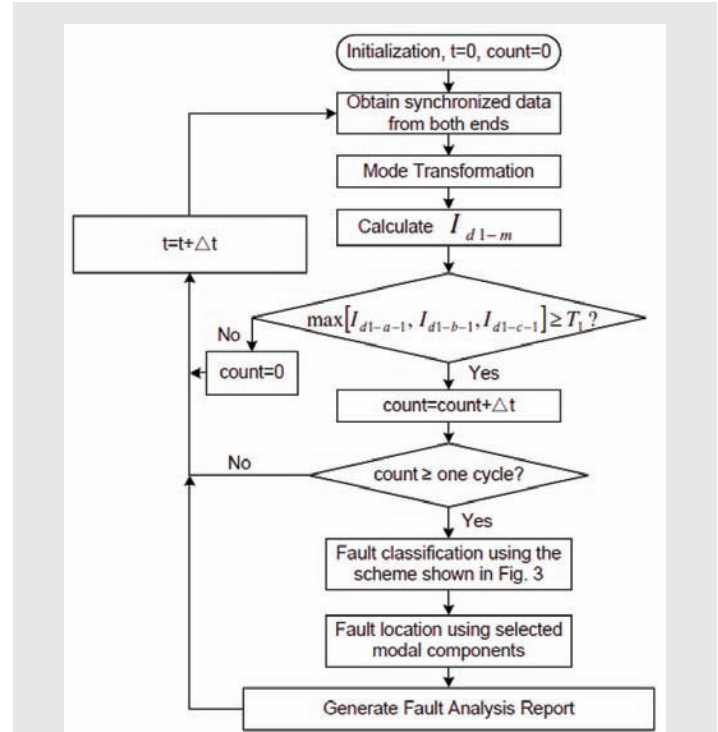


Figure C4 – Flowchart of Fault Diagnosis Scheme Using Synchronized Sampling

operating state. Therefore it is less affected by those factors. Compared to the traditional impedance based algorithms involving phasor calculation, SSFL uses raw data from time domain. Therefore it keeps the useful information in the waveform to locate the fault precisely.

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Appendix D: Fault Detection Based on Wavelet During Power Swing

During power swings the distance function or protective relays may provide erroneous readings. For this reason, the distance function is inhibited during power swings. This creates the problem that in case of an actual fault during the power swing, the distance protection will fail to respond to the fault. For this reason, it is necessary to develop methods that provide the correct location of fault during power swings. Wavelets analysis (Multi Resolution Analysis (MRA)) can provide a good solution to this problem. The method is described next.

Power swing is a phenomenon of large fluctuations of power between two areas of a power system. It is referred as the variation of power flow, which often occurs with the instability of synchronous generators. It is often caused by transmission line faults, loss of generator units, or switching heavy loaded transmission lines. The occurrence of power swings is very difficult to predict since they are quite unexpected [1]-[4]. When power swing takes place, the apparent impedance measured by a distance relay may move away from the normal load area and into one or more of the distance relay operating characteristics. This may cause unintended trips [5]-[7].

To ensure the security of operation, most modern distance relays detect and block the operation during the power swing. If a fault occurs during the power swing, the distance relay should be able to detect the fault and operate correctly. In that case it is necessary to unblock the relay during power swing. The procedure is easy to implement for unsymmetrical faults, since the negative and zero sequence components do not exist during power swing, which can be used as fault detection criterion. However, it is much more difficult to identify symmetrical fault during stable power swing, which may delay the operation of relay.

Appropriately selected wavelet-based method could detect and classify transmission line faults during power swing, which is aimed at avoiding possible relay mis-operations. By extracting the forward and backward traveling wave at the relay point, wavelet analysis is performed to get the spectral energy, which was used as

the criteria function for fault detection. Further details are given in reference [8] and [9].

Distance relaying behavior during power swing. The distance relays are proven to be influenced by power swing [2, 10]. Either stable or unstable power swing will have impacts on distance relay judgment. The detailed reasoning and an example of two machine system are given in reference [11]. If there is no fault on the considered transmission line, the impedance seen by distance relay at bus is,

$$Z_c = \frac{\dot{V}_m}{\dot{I}_m} = \frac{\dot{V}_m}{(\dot{V}_m - \dot{V}_n)/Z_L} = Z_L \left(\frac{1}{1 - \frac{V_n}{V_m} \angle \theta_m} \right)$$

From the above equation, the apparent impedance Z_c seen by relay is determined by two variables: the magnitude ratio (V_n/V_m) and the angle difference ($\theta_{nm} = \theta_n - \theta_m$) of the bus voltages at the two ends. Since the bus voltages will oscillate during power swing, Z_c will also vary accordingly. The plots of Z_c trajectories in the $R-X$ plane with respect to voltage magnitude ratios and angle differences is shown in Figure D1, under the condition of $Z_L = 1 \angle 80^\circ$.

During power swing, if certain values of the magnitude ratio and angle difference are satisfied, the impedance seen by relay will reach the zone settings and relay mis-operation will happen.

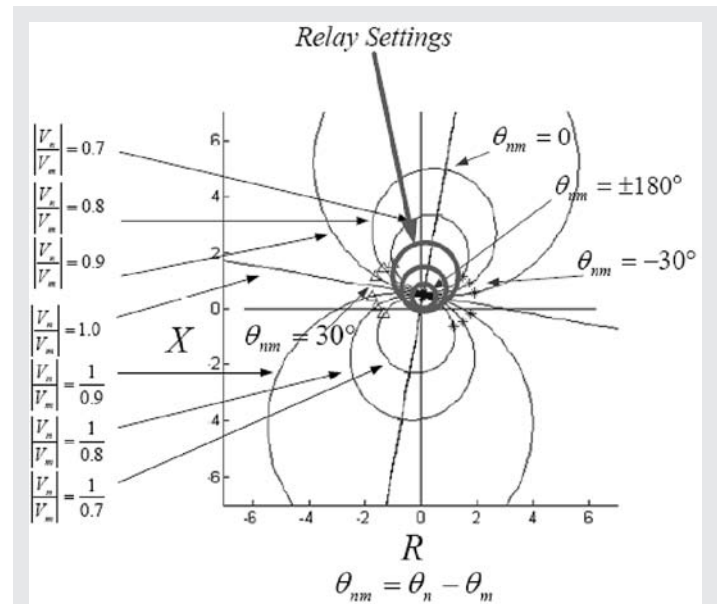


Figure D1 – Impedance Trajectory in the Complex Plane

Wavelet transform analysis. Wavelet transform (WT) is a relatively new and efficient signal processing tool. The performance of Wavelet transform highly depends on the selection of the mother wavelet. All mother wavelets have the common characteristics: the mother wavelet should be attenuating and oscillating. To perform Wavelet transform, many families of wavelets can be selected, such as Daubechies (Db), Symlets, Coiflets, and Biorthogonals [12].

Power swing is mostly the phenomena of low frequency oscillation. The fault voltage or current contains high frequency transient signals. The multi-resolution analysis (MRA) will be a best tool for decomposing the signal at the expected levels, by which the fault-derived signals can be represented in terms of wavelets and scaling functions. Thus, we can easily extract the desired information from the input signals into different frequency bands related to the same time period. Figure D2 shows the procedure of two-scale decomposition using MRA.

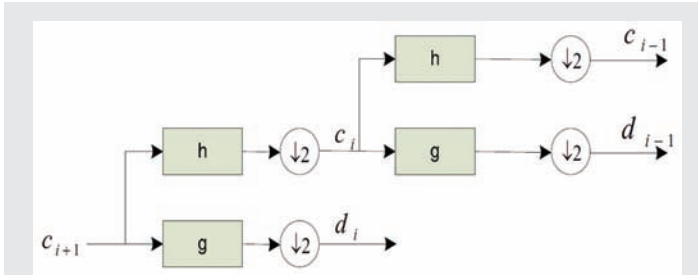


Figure D2 – Diagram of MRA Decomposition into Two Scales

Parseval's Theorem. In order to represent the high frequency component in quantity, the wavelet energy spectrum is used to calculate the transient energy in different frequency band. From Parseval's Theorem, the energy of the analyzed signal can be represented by the energy in each expansion components and their wavelet coefficients if the used scaling function and wavelets form an orthogonal basis, which can be shown as:

$$\int |f(t)|^2 dt = \sum_{k \in \mathbb{Z}} |c_{j,k}|^2 + \sum_{j=1}^J E_j$$

where $E_j = \sum_{k \in \mathbb{Z}} |d_{j,k}|^2$ is the norm value or the energy of the signal component at j level after wavelet transform.

Wavelet selecting. Considering Db8 wavelet is compactly represented in time, and this is good for the short and fast transient analysis due to its better localization performance in frequency. It is relatively easy to localize and detect the fault part under power swing by

extracting features of transients in the wavelet domain. Thus, multi-resolution analysis based on Daubechies-8 (Db8) wavelet is selected for the investigations.

Implementation of detection method. The diagram of proposed symmetrical fault detection method based on travelling wave technique and wavelet transform is conceptually shown in Figure D3.

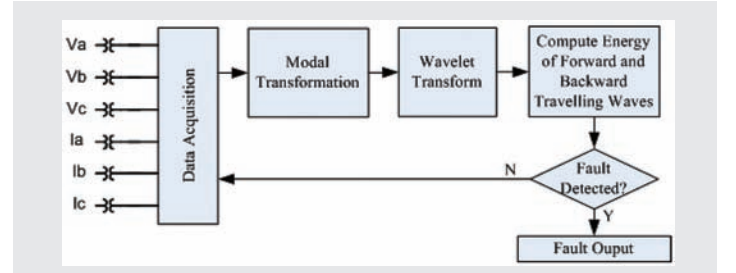


Figure D3 – Implementation Diagram of Symmetrical Fault Detection during Power Swing

The criterion for fault detection is defined as: $k_e = \frac{E_f}{E_b}$

where E_f and E_b are the energy of the d1 wavelet component for the forward and backward travelling waves u^+ and u^- respectively. According to the principles discussed above, E_f and E_b only exist after fault occurs, not only limited to symmetrical faults. Because of the reflection effects at bus boundary, E_f is bigger than E_b after the reflection at the boundary. Thus the fault detection criteria will be defined as: if $k_e \geq k_{e0}$, the symmetrical fault occurs. When it is used in practice, in order to avoid the possible situation of dividing by zero, the values of E_f and E_b are being monitored. If any of them is close to zero (for example, less than 10^{-5}), value of k_e is set to zero. The threshold value of k_{e0} is determined by the bus reflection coefficient. Here k_{e0} is set to be 1.15 after large number of simulation trials.

Figure D4 shows an example of values of criteria factor k_e around the fault point. It illustrates fault detection during power swing can be achieved using wavelet transform. Note the algorithm does not require any settings.

In summary, handling faults on transmission lines during power swings is problematic since in general the distance function during swings is inhibited to avoid false trips. The proposed method based on wavelet transform provide a method to detect line faults during power swings and facilitate the clearing of these faults.

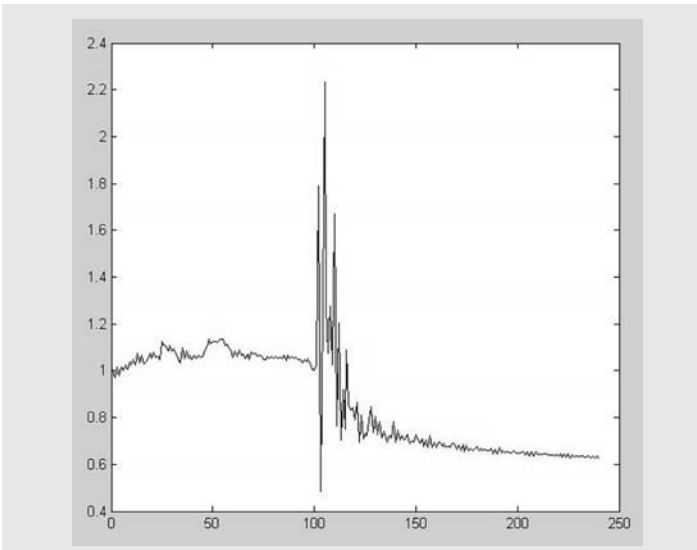


Figure D4 – Values of Criteria Factor k_e Around the Fault Point

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