BIOGRAPHICAL INFORMATION

Cindi Salas
Manager, Geographic Information Services
CenterPoint Energy

Specific Responsibilities
Cindi is responsible for data management; the operation and maintenance of the corporate, enterprise-wise GIS system; and all aspects of development and deployment of GIS information and technology throughout CenterPoint Energy.

Past Experience
Cindi has held various other consulting and supervisory positions in her 20+ years with CenterPoint Energy. She began her career with Allegheny Energy where she served in various engineering-related areas.

Educational Information
Graduate of LeTourneau University, with a degree in Business Management.

Professional Memberships
At-Large Member of GITA Board of Directors
Member of GITA Oil and Gas Committee
Coordinator for GITA ITAG for gas industry
President of the ESRI Electric and Gas User Group
Member of ArcGIS Pipeline Data Model (APDM) Steering Committee
Member of Houston-Galveston Area Council Geographic Data Committee

BIOGRAPHICAL INFORMATION

William J. Meehan, P.E.
Director, Utility Solutions
ESRI

Specific Responsibilities

Bill Meehan joined ESRI in 2002. He has extensive background in utility operations management including the integration of IT and GIS. Bill is the director of the worldwide utility solutions industry for ESRI, which includes electric, gas, pipeline, telecommunications, water and wastewater. His specific responsibilities include strategic industry planning, business development, sales support, and project consulting.

Past Experience

While employed at NSTAR, Massachusetts's largest investor-owned electric and gas utility, Bill held the positions of vice president of Electric Operations, vice president of Supply Chain, and manager of Engineering for NSTAR. He championed Boston Edison's GIS project and managed the NSTAR merger process of Boston Edison and Commonwealth Energy Systems. Bill also led the effort to comply with the Massachusetts Utility Restructuring (deregulation) Law.

Education

B.S. in Electrical Engineering, Northeastern University, Boston, Massachusetts
M.S. in Electric Power Engineering, Rensselaer Polytechnic Institute, Troy, New York

Professional Memberships and Affiliations

Registered Professional Engineer, Commonwealth of Massachusetts
Member GITA
IEEE, Power Engineering Society

Awards

Multiple GITA Speaker Award Winner

Publications and Presentations

Author of numerous papers, articles, and the textbook Power System Analysis by Digital Computer, Bill has lectured extensively and taught courses at Northeastern University and the University of Massachusetts. He has made a number of presentations and keynote addresses at a host of industry and business functions.

SETTING THE STAGE FOR DISTRIBUTION INTEGRITY MANAGEMENT

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ABSTRACT

The Pipeline Improvement Act of 2002 has created a huge demand for management, reporting, and coordination of data for liquid and gas pipeline integrity using GIS. Large pipeline operators have embraced a single Enterprise GIS. However, natural gas utilities with both transmission and distribution continue to struggle with the implementation of a unified approach to their enterprise GIS for pipeline integrity. Why? The current regulations extend into the distribution system for some qualifying high-pressure distribution systems. Yet high-pressure distribution is typically modeled more like standard networked low-pressure systems without the complication that integrity management imposes. Possible future regulations that extend into the gas distribution system will further complicate matters.

This paper will examine the challenges to the implementation of a unified enterprise GIS approach to both transmission and distribution. Issues such as high consequence area determination, assessment, work flow, data management, and organizational barriers will be raised. Finally, a large transmission and distribution gas utility will present its progress toward the vision of a single unified enterprise GIS to handle both the current and possible future distribution integrity regulations.

BACKGROUND

In the summer of 2004, an earthshaking blast occurred about 8:30 AM in an industrial area of the village of Ghislenghien, about twenty miles southeast of Brussels, Belgium. It could be seen and heard for miles. Emergency crews from across Belgium, France, Luxembourg and Germany rushed to help. A gray haze hung over the rural area as helicopters and fifty ambulances carried the injured to hospitals. Construction workers in the area had pierced a natural gas transmission line. Later that year near San Francisco, another pipeline let loose, injuring a number of people and causing countless thousands of dollars in property loss.

Perhaps the most well known accident in recent memory was the pipeline rupture and loss of life at Carlsbad, New Mexico in August of 2000.. The Carlsbad accident, other serious accidents, and environmental accidents from liquid pipeline accidents led the United States Congress to pass the Pipeline Improvement Act of 2002, which provides an increased level of federal oversight to pipeline design, construction, on-going inspection, and risk mitigation. Among its requirements, the law prescribes that pipeline operators execute a pipeline integrity management program. Regulators throughout the world recognize the danger of natural gas pipelines to people that live, work, and play near natural gas transmission lines. While the more dramatic scenes of damage and injury occur as a result of failure of a high-pressure line, regulators also recognize a different kind of danger from standard low-pressure gas distribution lines.

In just one metro area in the United States, the following distribution gas events have occurred:

Aug. 21, 2004: John, 49, is injured when his home explodes, ripping it apart. Authorities had been investigating a natural gas leak before the explosion.
April 4, 2004: a school blows up, destroying two classrooms. Authorities suspect a natural gas leak triggered the blast.
June 18, 2003: An explosion levels an apartment building, burning two women. A gas company crew was on the scene shortly before the blast.
June 6, 2003: A house explodes several hours after gas company officials discovered a leak in the neighborhood. John, 49, was critically injured.
May 3, 2003: A natural gas explosion destroys a home. Robert and Eleanor and their adult son are rushed to the hospital, and eight families nearby are evacuated.
March 22, 2000: Albert, 61, and wife, Janice, 59, are injured when their home explodes. The local gas company is named in a lawsuit.
Sept. 7, 1998: Ann, 72, dies while screaming for help, trapped in her house after a natural gas explosion. Investigators blame the blast on a miss-marked gas company line that was pierced by a digging crew.

Regulators in the United States are currently looking at increasing the safety oversight for distribution systems. In May of 2005, the Office of Pipeline Safety (OPS) presented a report to the United States Congress entitled “Assuring the Integrity of Gas Distribution Pipeline Systems.” In that report, OPS makes the following points:

1. Gas distribution networks continue to pose a risk to the public
2. Gas distribution networks are significantly different in construction, management and operation from transmission pipelines
3. Additional integrity management is required for gas distribution systems that currently exists
4. Current integrity management regulations per Federal Standards 49 CFR Part 192 are very likely inappropriate and in fact impractical for gas distribution

The current US regulations apply to all natural gas transmission pipelines. While the focus and attention of the law was on natural gas *transmission* and the consequences of high volume, high-pressure system events, the current law applies to some *distribution* mains, those operating at high-pressure and in areas of significant human activity. This is because transmission is not defined by organizational structure, business application, or plant accounting principles.

According to 49 CFR, Part 192, § 192.3 Definitions, a transmission line means a pipeline other than a gathering line that:

a) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not downstream from a distribution center.
b) Operates at a hoop stress of 20% or more of Specified Minimum Yield Strength (SMYS)
c) Transports gas within a storage field. A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

49 CFR Part 192 Subpart O - Pipeline Integrity Management delineates the regulations for Integrity Management. §192.901 states that the regulations apply to all transmission lines *as defined above.*

NATURAL GAS PIPELINE SYSTEMS ARE NOT ALL THE SAME

Keeping in mind the regulatory definitions of transmission, there are four separate types of natural gas pipeline systems:

- Gas Transmission Systems. Facilities in this category are those high-pressure, high volume pipelines that have historically been operated by either pipeline companies or by utilities. There is no ambiguity about whether these systems are classified as transmission by both federal definition and by company organization.
- High-pressure Distribution Systems. These facilities represent high-pressure distribution mains, operated by natural gas local distribution companies (LDC), but have been classified as transmission by 49 CFR Part 192 Subpart O and under §192.901 must comply with the new integrity regulations.
- Gas Distribution Systems. These facilities are low-pressure systems installed in a network in close proximity to the end use customers. In the United States, each state has the authority to regulate these systems in concert with the DOT.
- Natural Gas Gathering Systems. These facilities are lower pressure than transmission and are more akin to gas distribution than transmission, but have their own unique characteristics and rarely are operated and maintained by utilities. Gathering systems will not be covered in this paper.

So the problem for LDC's is two-fold:

1. How to comply with the current integrity management requirements for some portions of their distribution system that are federally classified as transmission but operated as distribution.
2. How to prepare for the coming and uncertain regulation for integrity management for the remaining distribution network

Operators will be required to have a high degree of solid data management of their pipeline asset information. Today most transmission pipeline operators use some form of Geographic Information Systems (GIS) to manage their pipeline facilities. The current regulations have intensified the need to use a more formal approach to their pipeline asset management system using GIS. With the future distribution integrity management on the horizon, LDC's will most assuredly require a robust, data rich, and highly accurate GIS.

DISTRIBUTION IS DIFFERENT

So why all the fuss about distribution integrity management? Why not just apply the transmission integrity management regulations to gas distribution? A pipe is a pipe. Right? The answer is that gas distribution is different. At the heart of transmission pipeline integrity management are the following key concepts:

<u>High Consequence Areas (HCA)</u>

These so-called HCA's are regions surrounding the transmission lines are mathematically calculated based upon potential impact circles. This innocent-sounding circle phrase implies that should a rupture of the pipeline occur and ignition results, very bad things will happen to anyone within that circle. HCA's are determined based on the size and pressure of the line and the structures that are nearby. Clearly, structures that limit evacuation, like prisons, day care centers, and high-rise buildings represent the greatest risk.

Distribution is different.

Distribution systems are low-pressure, so they don't rupture like transmission lines. They are almost always in areas of high population since they are close to customers. Nearly every structure that has gas service would be included in the potential impact radius. The difference, of course, is that the problem with distribution is not rupture and ignition, but gas leaks. When a low-pressure gas line leaks, the gas typically flows slowly out of the gas line underground. The danger is when the gas travels into confined underground areas or basements. Once the gas density reaches a set value, it has the potential to ignite. The common source of ignition is someone turning on a light. The gas from a leak could migrate a long distance from the actual source, so HCA's don't really make sense for low-pressure distribution.

A common problem in distribution is third party damage. This occurs when a contractor digs into a line. While this happens with transmission lines occasionally, it is all too common in distribution. So HCA analysis has little relevance to gas leaks and dig-ins. These events are the most common causes of gas distribution accidents.

However, some high-pressure distribution mains will in fact rupture and ignite, just like transmission. So HCA's do apply to a class of high-pressure distribution.

<u>Condition Assessment</u>

A critical component of transmission pipeline integrity management is condition assessment. The most important condition is the pipeline's resistance to rupture. Corrosion and subsequent reduction of the thickness of the pipe wall is the most important consideration. Common methods of assessment are inline inspection, pressure testing, indirect assessment, and direct assessment.

Transmission pipelines are single, long lines that extend for miles with few branches. Transmission pipelines are equipped to handle internal inspection devices that are able to view the interior of the pipeline for evidence of corrosion and subsequent shrinking of the pipe wall. In the Carlsbad, New Mexico accident, the pipe wall had deteriorated to fifty percent of its original thickness. Transmission lines are designed to launch these internal or inline inspection devices, called pigs, and capture the data about the condition of the pipeline electronically.

When a pipeline is first built or significantly modified, it is pressure tested using often using water. The ends are capped and the pipe is inspected for leaks and ruptures. This cannot be done while the pipe is in service.

Indirect assessment involves using a proxy measurement device to detect corrosion. The most common is cathodic protection (CP). In addition to helping prevent corrosion, CP systems also measure electrical impulses. The differences in the values of the electric current give evidence of corrosion, and the location can be tracked fairly accurately.

Finally, direct assessment simply means looking at the pipe to visually inspect for corrosion or some other kind of damage. Direct assessment means that the pipeline has to be excavated to be examined.

Distribution is different.

Gas distribution pipes are small, not designed to accept pigs, are more often than not made of plastic, and have many turns and bends. In-line inspection is not possible on gas distribution. Pressure testing is impractical, since the segment that is to be pressure tested must be out of service. This would create customer outage. It may also be difficult to evacuate all the water. Cathodic protection works well on modern coated pipe, but CP protects only a fraction of the total system. Cathodic protection is not possible on plastic pipe.

While HCA makes sense for high-pressure distribution mains, the transmission assessment methodologies of inline inspection, pressure testing and indirect, assessment are problematic for many of the same reasons that exist for standard distribution lines. In order to comply with the integrity management regulations, operators may be forced to assess directly. That can be extremely costly and risky. Outstanding and accurate data will help to optimize the sections of pipe that have to assess directly. GIS is the tool to capture that information.

Information Gathering and Management

Natural gas pipeline companies and gas distribution utilities have been collecting enormous amounts of information about their facilities for years. However, the processes, methods, documents, and map products are very different. Critical data, such as inspection reports, accident reports, inline inspection databases, photography, and general facilities data, have not always been well coordinated. This is further complicated by the different organizational structures (transmission vs. distribution) that persist in companies where different groups with different missions manage the data. Companies that do not have gas transmission have little or no experience with the reporting and modeling of transmission lines. GIS provides the enterprise level tools to consolidate the disparate data and spatially reference the data to facilities.

Data models are a proven methodology to deal with spatial, attribute, relationship and behavior information about the transmission and distribution system. Like the systems, transmission and distribution data models and representations can be quite different.

MODELING THE DATA

Over the past decade, GIS vendors, pipeline application providers and operators have worked collaboratively to develop pipeline data models. The three most common pipeline open data models used in the US are

- ISAT or Integrated Spatial Analysis Techniques. ISAT was originally developed in 1995 by a team of representatives from various organizations and pipeline industry vendors. According to the ISAT web site, it was designed to be customizable and has been expanded for numerous clients to support data integration, field data collection, one-call, right-of-way, environmental, marketing, risk assessment, and pipeline integrity applications. It is a data base schema that does not deal specifically with GIS but is designed to integrate with GIS.
- PODS or Pipeline Open Data Standard was developed early in 1998. PODS became an official association in August of 2000. PODS was based on the work of ISAT with input from additional transmission users and vendors. Since its inception, it has deviated from the original ISAT data model. While it is sometimes referred to as ISAT 2.0, it is a separate data model independent of ISAT. Like ISAT, it does not deal specifically with GIS, but is designed to integrate with GIS.
- APDM or ArcGIS Pipeline Data Model. Unlike PODS and ISAT, or the European funded ISPDM (Industry Standard Pipeline Data Management), APDM, published in 2003, was not intended to be a pipeline data model standard. Rather, it was designed as a template for pipeline data fully integrated with a specific GIS platform. It incorporates much of the work of ISAT and PODS. What differentiates APDM from the others is the ability to deal with both referential and spatial integrity in one database, since APDM is structured explicitly around the GIS, not as adjunct to the graphic or spatial representation.

While there are significant differences in each of the data models, they have one thing in common. They are structured to handle linear referencing; that is, the ability to locate a point along a pipe from another reference location on the pipe. A linear referenced model is far superior to a distribution model for high-pressure transmission pipeline because of the need to mix and match difference data types, or overlays, without splitting the pipeline at each attribute change. A critical characteristic of this model is the ability to look at overlapping ranges of pipeline. Long sections of pipe with similar range features (pipe size, coating, wall thickness, SYMS) are modeled as if they were a single section of pipe, even if the event feature (gouges, welds, dents) intervened. Another term for this approach is dynamic segmentation, which recognizes that events or points along the pipeline occur dynamically, but don't create a distinct node point.

Stationing, Control Points and Station Equations

The location of events, equipment, and features along a transmission pipeline has historically been determined by what's referred to as station series and station value. This terminology predates GIS, GPS, and computers. A station series is a linear path representing a portion of the centerline of the pipeline or the route that the pipeline follows. The measure of the distance from the start of the station series to the end is referred to as station position. It is possible, therefore, to have many events located along the station series representing the location of a feature or the start or end of a feature. At each point along the station series, where the centerline bends, a control point is placed.

The station series and station values are determined when the pipeline is first constructed. Real events that happen in the field, like dig-ins, leaks, gouges, and inspection reports all relate to the station values. Regulatory reports of events that go back many years are also referenced to the station values. The problem occurs when a new section of pipe is added or moved and that changes the length of a pipe segment. Rather than redo all the station values, standard practice is to adjust or compensate for the new section of pipe, while retaining the existing station values in the non-impacted areas. The points of the breaks in stationing are known as station equations.

Two things are unique to transmission data models

- Linear referencing or dynamic segmentation
- Stationing (station series, station values, control points and station equations).

<u>Distribution Data Models</u>

Distribution is different, a lot different.

While ISAT and PODS and, by extension APDM, were designed to capture all kinds of data about the pipeline, no such data base model exists for gas distribution, or if it exists, it isn't common. What do exist are gas distribution *GIS* data model templates. Some vendors publish data models for gas distribution that have been built by a consensus group of users and application providers.

GIS gas distribution data models are called network data models. They use the classic node span, where each section of pipe between nodes is treated as a separate element. The critical characteristic of this model is the ability to trace along the pipe around the network. Connectivity is critical. While transmission lines are typically long spans of single lines, distribution pipes have multiple paths up one street and down another. The location of distribution points (nodes) is based on real world coordinates and is created where two or more pipes come together to form a node. Linear referencing could have application in distribution lines, especially for long spans of critical mains and for high-pressure distribution mains that are classified as transmission by regulation. However, stationing is rarely, if ever, used in distribution. Why is that? The simple answer is probably that it was never needed for the business of gas distribution. So LDC's never applied it.

Is stationing a legacy process? It predates GPS. An argument could be made that stationing overly complicates the data processing of transmission pipeline data. The difficulty is that historic data is linked to stationing. Even the current reporting of transmission pipeline data to the National Pipeline Mapping System (NPMS) is linked to this process. Abandoning stationing might result in the loss of critical reference data. Field work flows and tagging are tied to stationing. The set of alignment sheets for the pipelines is the bible for operators. These are historic and linked to stationing.

Distribution companies never use alignment sheets. Distribution lines are most often displayed on map grids. Since distribution companies never adopted stationing, the location of points along the distribution network can be accurately located with GPS, and that data can be easily assimilated into the distribution GIS data model.

HOW TO MODEL HIGH-PRESSURE DISTRIBUTION

It is clear from the OPS report to the US Congress that even though the integrity management objectives of transmission and distribution are very similar, the practical implementation of distribution integrity management will be very different. Since much of the regulatory reporting for future distribution integrity will be managed by the states and not the federal government, it is likely that the states will not adopt a transmission reporting model for distribution. Further, there are no distribution historical records of accidents or leaks or events that refer to stations. In effect, the states and the distribution companies can start from scratch using the latest technologies available.

So what do LDC's do about the high-pressure distribution mains that have no historic legacy of stationing or control points, but still have to be integrated into the transmission integrity management processes?

In our paper presented at the 2004 GITA Oil and Gas Conference entitled *Modeling High-pressure Distribution For Integrity Management*, we noted there were three possible models:

1) Create a new single data model that includes classic gas transmission, high-pressure distribution that conforms to the definition of transmission, and conventional low-pressure distribution mains and service lines.
2) Continue the transmission and low-pressure distribution models and create a third data model for high-pressure distribution mains that conforms to the definition of transmission.
3) Continue the two data model approach and treat the high-pressure distribution as transmission only for analysis purposes.

Given that OPS recognizes integrity management for distribution will be very different from transmission, it would not make sense to complicate the extensive gas distribution system by introducing stationing. So attempting to consolidate all gas transmission and distribution data into a single, all encompassing, data model including all integrity management considerations isn't practical. From a regulatory reporting, workflow, simplicity of process, and data development, having a separate model for transmission and distribution, makes sense.

From a user's perspective, it is important that the two data models interoperate easily and perhaps employ the same look-and-feel, or share common tools. The underlying data models should be different.

At least until the final rules on distribution integrity management are finalized, and more experiences are gained on the full high-pressure integrity management, it also makes sense to create a high-pressure distribution data model, which has much of the characteristics of the transmission data model (since it by regulation transmission), at least for temporary analysis. At that point, the operators will have to make a decision on the data maintenance process. That is, update the data in one and propagate the changes to the other, or make the updates in both models. These are still open issues.

PRACTICAL IMPLEMENTATION AT CENTERPOINT ENERGY

In recent years, CenterPoint Energy consolidated all of its GIS operations into a standard GIS platform used for both electric and gas transmission and distribution systems. As it pertains to gas distribution, one model and one common data repository were designed and are in use today by various CenterPoint Energy business units and departments. While this combined distribution environment meets all the day-to-day electric and gas distribution GIS needs of CenterPoint Energy, it does not provide a model upon which OPS-required high-pressure pipeline integrity management, analysis, and regulatory reporting can be achieved.

Both the low and high-pressure distribution system data is currently maintained in a networked data set. For the reasons described earlier in this paper, the current models are not compatible with a linear referenced model required for high-pressure distribution pipeline applications, which qualify as transmission under US Federal regulations. CenterPoint has, therefore, designed and implemented a linear referenced model based on the APDM data model. While PODS is in use within CenterPoint Energy for transmission pipelines, APDM was chosen to leverage existing in-house expertise and provide a framework for facilitating pipeline integrity requirements in the near as well as long term.

In the final phase of APDM implementation, pilot data migration was performed. The purpose was to test the migration of standard GIS data for high-pressure distribution into a fully linear referenced data model. Rather than recreating an extraction process from scratch, CenterPoint Energy utilized an existing extraction process that was used to report the high-pressure distribution system data to the NPMS (National Pipeline Mapping System) in an accepted data exchange format. The pilot data was loaded into the data model, and supplemented with additional integrity-related data from other data sources. Since one of the core elements of APDM (and all other transmission data models) is stationing and control points, those were automatically generated.

While linear referencing was needed absolutely, the project team noted that adding stationing and control points was not strictly needed from a business objective. Not adding stationing would, however, have required that a new data model be created just for high-pressure distribution. By adopting a standard gas transmission data model, CenterPoint could take advantage of certain commercial pipeline applications that run against the APDM data model.

The results of the pilot were positive. Automated procedures for creating the data model were tested and validated. Viewing the newly converted network data set into a linear referenced data set allowed CenterPoint Energy to perform additional data quality checks. Various data errors were noted and corrected.

With the pilot successfully completed as well as data clean-up, CenterPoint Energy is now in progress with the initial data loading from the distribution model. However, there are many challenging issues ahead. The first issue involves a determination of how to most efficiently accommodate the high-pressure transmission data within both data models. The distribution model needs this data as part of the network for tracing (i.e., outage management, pressure studies, and services from transmission). Secondly, multiple supplemental data sources exist in various formats, as well as data that have yet to be collected. The actual migration of that data is one challenge, but just as importantly, the processes for ongoing maintenance must be decided for an enterprise operation that encompasses multiple business units and existing practices. The third major issue involves the implementation of integrity management applications (i.e., risk assessment, HCA and Class, alignment sheets, etc). Based on evaluations to date, some of these applications exist; however, many of them are just in the formative stage. Core functionality of the GIS must be considered and weighed against existing and forthcoming off-the-shelf applications, as well as custom development in-house.

Internal and external challenges will always exist. But with their new linear referenced model established and data migration underway, CenterPoint Energy has built a solid foundation and a good starting point for pipeline integrity management.

SUMMARY

It is clear that there will be new gas distribution integrity regulations within the next few years. Distribution is very different from transmission, so it is unlikely that the current transmission integrity models will apply to distribution. However, the current natural gas integrity management regulations apply to some high-pressure distribution systems. Utilities must create workflows, analysis techniques, and reporting means to deal with this regulatory impact. Since transmission has been modeled quite differently from distribution, this offers a challenge to operators, who have both transmission and high-pressure distribution. Creating a single data model overly burdens the workflow of both systems. CenterPoint Energy examined a number of possibilities, and along with some redesign of work flows, created a practical pilot approach to modeling high-pressure distribution.