Geographic Pricing

By: J.D. (Jim) Wilks Dip EE, Grad Dip MS
DataShare Power Engineering Software

Summary

The development of the competitive market for electric energy has instigated a re-examination of electricity pricing practices and the discontinuance of some past uniform-pricing policies.

It well known that the cost of supplying electric energy involves factors relating to not only the quantity used, the rate of usage and the pattern of usage over time, but also to the location at which the usage takes place. Past uniform pricing policies have typically recognised only very broadly classifications of the place of usage (eg. urban and rural). Now, with the division of electricity supply into network and retail sectors, new policies are being adopted that allow electricity charges to include network loss factors relevant to the location at which the electric energy is supplied.

This paper draws on the experience gained through a joint consulting assignment performed for an Australian electricity utility with a widely geographically dispersed transmission/distribution network to determine appropriate loss factors for the network. It also describes how, as part of the project, data on substantial parts of the network was computerised and geographically encoded through the use of a PC-based mapping system.

The resulting geographical information system (GIS) preserves and makes readily accessible not only the data that had to be collected for the project, but also additional data it was decided could be collected for only a marginal increase in cost. This geographically related data was created at a relatively low cost and is expected to help make future loss factor assessments much easier to implement and will greatly assist many other tasks required of the network manager.

DataShare Power Engineering Software
PO Box 772, Mona Vale, NSW
Australia.
Phone: + 61 2 9979 7240
Fax: + 61 2 9997 1339
Email: dpes@ozemail.com.au

Introduction

The introduction of the competitive electricity market and the separation of network ownership/operation and energy retail functions has forced the abandonment of many past pricing practices and the adoption more economically rational ones.

This includes taking proper account of the intrinsic values electricity has an energy source that has long been recognised. For example:

> "The electricity purchased by the customer has four attributes of value to the customer. The fundamental one is the energy content … The energy is the basic commodity being purchased. The second and third components are the ability to obtain at any time electricity at the rate required by the customer. The fourth desirable quality of electricity is its delivery right to the point of consumption."[1]

It also involves abandoning long-practised price discrimination:

> "Price discrimination is widely practiced throughout the (electricity) industry.
>
> Several of the more important types of price discrimination may be distinguished in the sale of electricity.

> - Peak-Off Peak discrimination …
> - Block discrimination …
> - Inter-class discrimination …
> - Geographic discrimination (that) exists when remote low density customers with high "consumer" costs enjoy the same tariffs as applied to high density urban customers close to bulk supply points."[2]

All of these forms of price discrimination have been widespread – not just in this region, but internationally! The introduction and maintenance of such price discrimination … especially the latter two forms (ie. inter-class and geographic discrimination) … has generally been motivated entirely by political considerations.

Distribution Loss Factors

When a customer has a free choice of electricity retailer, and the chosen electricity retailer has a right to unfettered access of the local distribution network to deliver the energy required by the customer, issues of customer location and the measure of losses involved in supplying that customer become significant.

It becomes necessary to recognise, evaluate, account for, and make price adjustments for the losses that occur in the electricity delivery system. This includes both transmission and distribution systems … however, this paper focuses only on distribution network losses.

When an electricity consumer is the customer of a retailer who does not own and operate the local electricity distribution network to which the customer is connected, the customer is referred to as an "embedded customer". A number of transactions involving the supply to that customer require adjustment to due to the losses involved in supplying that customer through the local network.

Of course, when there is complete segregation of network ownership and electricity retailing then effectively all customers are embedded in someone else's distribution system! In these circumstances it is crucial to have an agreed method of accounting for losses to make the financial transactions between the participants in the competitive market truly cost-reflective.

The mechanism traditionally used to take account of these losses – at the distribution level – is by Distribution Loss Factors (DLFs) assessed for each distribution network involved in the market.

What is a Distribution Loss factor (DLF)

A definition of "distribution loss factor" given in the Australian National Electricity Code is:

> " … a distribution loss factor is … a factor that describes the volume weighted average electricity loss incurred in the distribution of electricity between a transmission network connection point and … loads connected to it through a distribution network for a defined period of time and associated operating conditions…"[3]

The DLF assessment must take into account the assets involved in supply different customer loads from the "*transmission connection point and… loads connected to it through a distribution network*". This "distribution network" potentially consists of both sub-transmission network assets in addition to high and low voltage distribution assets. And the assets utilised by even the one "class" of customer may vary - for example, a low voltage commercial may supplied directly from a distribution transformer, or from a "lossy" length of low voltage mains beyond a distribution transformer.

Figure 1 illustrates some of the variations in the distributors assets used to supply customers.

The distribution loss assessment methodology must be:

1) technically sound … and able to be substantiated if challenged.

2) reasonably amenable to assessment (as will be shown, it is a calculation intensive process that can

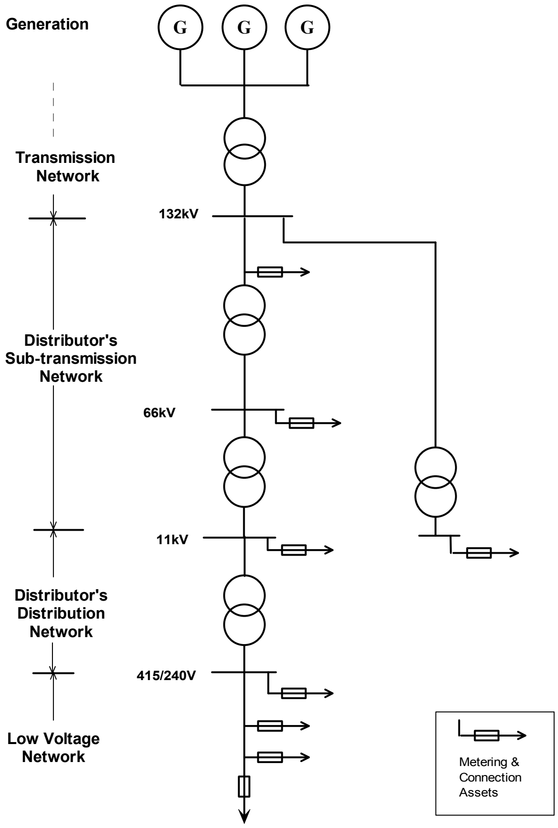

Figure 1: Typical Network showing customer connections at various "levels"

require considerable input data).

3) universally accepted …at least by the market participants!

DLF Methodologies

There seems to be no universally accepted, or prescribed, methodology for the calculation of Distribution Loss Factors (DLFs) but there are generally common features to most of the methods presently used.

Assessment usually involves the following main steps:

1) determine the magnitude of the losses that occur at the various parts of the distribution network from which customer loads are supplied by performing a series load flow analyses. This is performed either on the whole network (most common) or on parts of it taken to be representative of all similar parts of the network (usually used when data is limited).

2) convert the demand component of losses reported by the load flow analysis to annual energy losses. This is accomplished by the application of an appropriate Load Loss Factors (LLF). The LLF may be actual (ie. derived from metering records) or is often empirically estimated from the Annual Load Factors (ALF) .

3) calculate the losses at the various parts of the network as a percentage of the outputs flowing through that part of the network

4) scale the losses to be consistent with the long-term average (3 or 5 years) of total system losses

5) express the final results as a factor that can be applied to inflate metered loads to include the assessed distribution losses.

Data Requirements

In addition to the line and transformer impedance data needed for the load flow calculations, considerable metering data is also needed. Preferably this metering data should consist of full load profile information and not just peak demand and total energy values.

If load flow calculations are based on peak loads then it is necessary to have sufficient metering data available be able to determine either the after-diversity contribution of major loads to that peak load, or to have concurrent load data for key points on the network to allow loads to be scaled to correspond to those loading conditions.

The amount of data required for DLF assessment, especially when full network modelling is undertaken, is immense. The task is as much (or maybe more) a data collection and processing exercise than it is an engineering analysis process. This aspect of the task should not be underestimated, and it is important to have a suitably balanced set of skills in the project team.

A 1998 DLF Assessment Assignment

The DLF assessment project that provides much of the experience on which this paper is based was a cooperative trans-Tasman project jointly carried out by Auckland-based

Power Consultants (through their Sydney office) and Sydney-based *DataShare Power Engineering Software.*

An Australian distributor with a geographically diverse distribution network commissioned the project. Their network includes both sub-transmission and distribution elements, has a number of significant "embedded customers" and other "contestible customers", and has multiple points of supply from different transmission networks.

The project had to be completed quickly and, though there was a reasonable amount of metering data available, data on the sub-transmission and distribution networks was fairly limited. The available network data was mostly fairly "raw" data, often existing only on marked-up copies of plans (mostly geo-schematics) or just in construction plans - strip maps and pole schedules! It quickly became evident that a major part of the work would involve collection and organisation of basic network data and, in the case of the metering data, there was a particular need to be able to process the data to extract the required data.

Meter Data Processing

The metering data came from a number of different metering systems with different file formats. Where the meter system supplier provided processing software generally the results available did not include the summary data required for this exercise.

Fortunately most of the metering for the "inputs" and "outputs" to and from the network was in two main file formats and stored mostly in MS Excel spreadsheets. Data summaries needed were mostly produced by custom-written code modules in MS Access or, in some cases, manually extracted from the files.

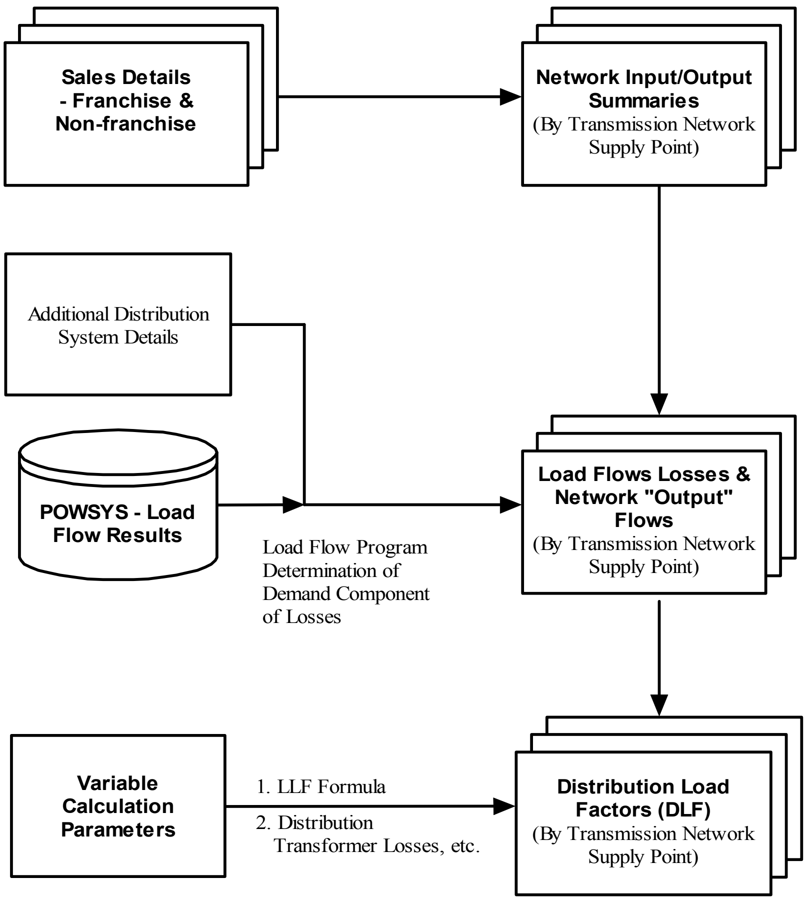

Figure 2: Data Inputs and Worksheet linkages

Format of DLF Workbook

To simply re-calculation with refinement of the input data during the course of the project - and especially to lay a foundation for calculations in the future (annual updates required) the main calculations were performed in a MS Excel Workbook with extensive linkages between individual worksheets. The main data inputs and worksheet linkages are illustrated in Figure 2.

Geographic Information

Early in the network data collection phase it became evident that a great deal of basic data needed to create the study files for the load flow analyses could be given added and lasting value to the client for a marginal increase in collection costs. This involved getting much the attribute data that had to be collected into a relational database and creating geographical maps of the lines through the use of a PC-based desktop mapping system.

This proved an attractive option for the client. They lacked any substantial geographical mapping of their distribution network and also needed a better information base on which to implement improved asset management systems.

Computerisation of Pole Schedule Data

The client had detailed strip maps and pole schedules for many of the lines – some built more than 35 years ago. But there was also an extensive electrification scheme constructed in the early 1990's where in addition to the strip maps/pole schedules there was geographical positioning system (GPS) locations data available for start, end and deviation poles.

It was decided to computerise these and interpolate location information for the intermediate poles so that all these assets could be geographically mapped. The pole schedules and GPS data were converted to computer readable form by a mixture of manual data entry and using optical character recognition (OCR) of scanned images of documents.

Details of more than 11,000 poles were computerised.

Mapping of Network Assets

The geo-coding of longitude and latitude of intermediate poles was accomplished by importing the poles into a Microsoft Access database and programming a code module to carry out the interpolation of poles between points with known GPS locations.

Two levels of Quality Control were applied to this conversion process. Each was based on a comparison between:

- the calculated distances between each of the two sequentially ordered poles with GPS data and
- the distance obtained from differencing the chainage from the pole schedules for these two poles (equivalent to the sum of all the spans between the poles).

At the first level of quality control where the discrepancy was a very small percentage the resulting interpolated data was tagged for review. Where large percentage differences were encountered no interpolated values were calculated and recorded. Generally, a failure to meet this second level of quality control was due to:

- errors in the data
- missing GPS data for some start, end or deviation pole

In one case, the discrepancy was found to be due to some of the poles positions being recorded to a different datum than the rest of the poles!

Digitising

Another substantial part of their distribution network had little data available other than a set of geo-schematic maps (much more "schematic" than "geo"!) but someone in the regional office had marked up a set topographic maps to show the locations of most of the network. It was decided to digitise these marked up plans so that these lines could also e included in the desktop mapping system.

Resulting Desktop Mapping of Network Assets

The extent of the value-adding to the data collected that was accomplished as part of this project is illustrated in Figure 3. It shows pole attribute from a database of the type created for the client being displayed through the desktop mapping GIS interface integrated wit the database.

Future Work

There is still considerable scope to still add much more value to the data collected for this project. At the conclusion of the work all the attribute data from the computerised pole schedules had been added to the database, but only a limited amount of time had been able to be allocated to resolving data anomalies revealed by the quality control

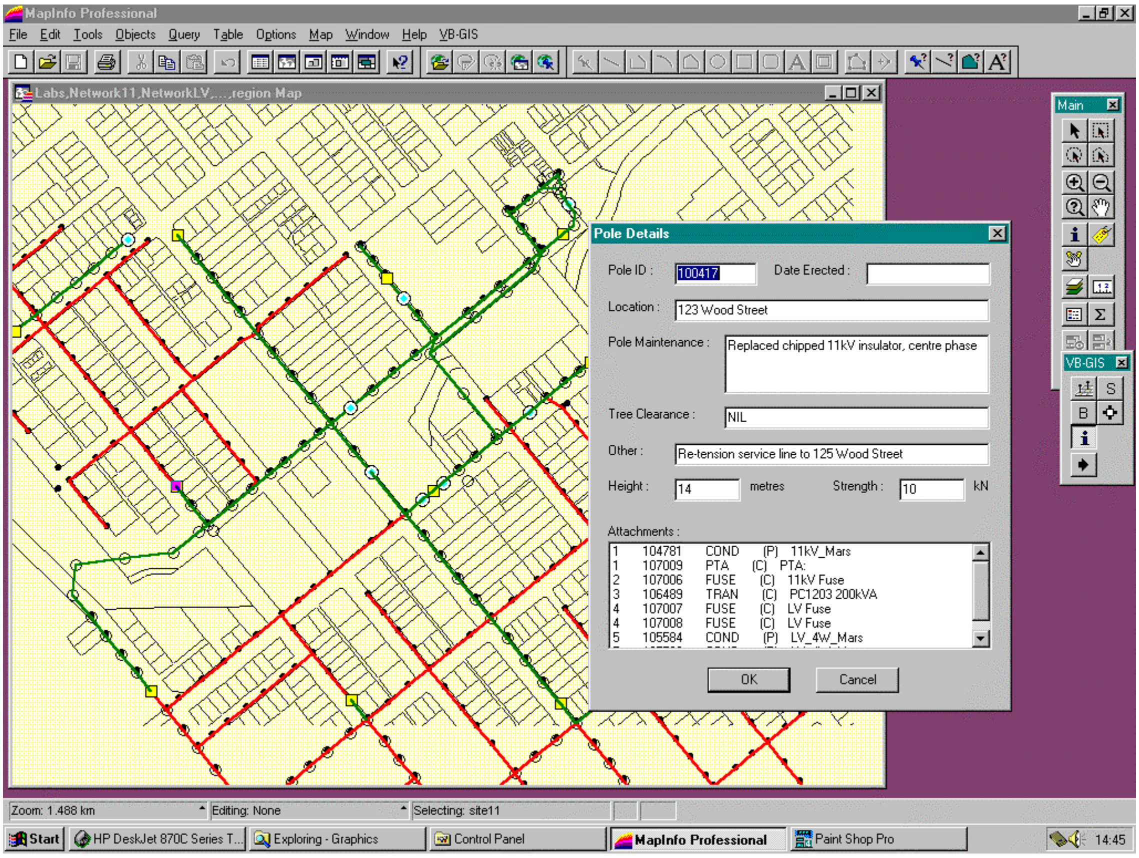

Figure 3: An example of the display of pole attributes retrieved through the GIS interface.

checks. Also, only very limited time was able to be spent on adding details of the electrical connectivity of the network to support circuit tracing and locating assets according to where they are connected within the network.

The digitised lines also need further processing and the addition of more attributes to make this data more useful.

Conclusion

At the end of the project the client had much more than the set of Distribution Loss Factors they needed and had initially set out acquire. As a valuable by-product … and for only a marginal increase in costs … they now have a permanent record of a vast array basic information about their network stored in a relational database and with a significant part of that network now geographically mapped through a desktop GIS interface integrated with that database.

References

1. Anderson, John, Electricity Tariffs with Particular Reference to New South Wales – A Thesis Presented to the Department of Economics, Wollongong University College, The University of New South Wales 6th September 1968 (Unpublished), page 3.
2. *ibid*, page 13-14.
3. National Electricity Code (Australia)