Observations on the Workshop on Markets for Electricity – Economics & Technology (MEET)
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1. Introduction

The MEET workshop brought together a wide range of influential thinkers to discuss network-related issues in electricity industry restructuring and, in particular, a proposal for "flow-based" network congestion management.

Following the MEET workshop, Hill Huntington suggested that I write an expanded version of the concluding remarks that I made at the workshop. This document is the result. It is written in the form of observations rather than prescriptions and from the more limited perspective of an external observer rather than an active participant in the US debate. It draws on insights from the Australian experience where these appear to be relevant. There is no claim of either omniscience or completeness and no claim that the Australian implementation of electricity industry restructuring is directly relevant to the USA. However network congestion is an important issue in Australia and has had to be considered carefully in wholesale electricity market design. This experience may provide useful insights.

The document is structured as follows. The key points that I made in my remarks are first summarised in terms of questions that it might be fruitful to examine further. These are then discussed in turn. The final section provides some general observations and conclusions. An epilogue was added on 11 October 2000.

Points made in my concluding remarks at the MEET workshop

In my concluding remarks I suggested that the following questions appeared to me to underlie the issues that remained contentious and/or unresolved at the end of the workshop:

- To what level of detail should networks be represented in commercial electricity trading?
- How does bilateral trading compare to simultaneous auction trading? When might each be appropriate?
- What network-related risks can be successfully commercialised and how is this best done?
- Is the preferred representation of network effects in the Western System likely to differ significantly from that on the East Coast?

To what level of detail should networks be represented in commercial electricity trading?

Both locational marginal pricing (LMP) and flowgate (FG) approaches to market implementation incorporate network models, however the models used differ greatly in their degree of abstraction.

In an ideal implementation of the LMP approach, each network element included in the scope of the market would be individually represented using an AC load-flow model. However, to the best of my knowledge, DC load-flow models are sometimes used and distribution networks are not included in any current implementations of LMP. At least in some cases, sub-transmission networks are not included. Thus practical LMP implementation involves some degree of modelling approximation. There are both engineering and economic arguments for avoiding the inclusion of distribution and sub-transmission networks in LMP markets and they will be discussed shortly.

The FG approach proposes a much more significant approximation in which the main transmission network is modelled by a relatively small number of potential transmission constraints or "flow gates". Also, power transfer distribution factors (PTDFs) are used to represent how a particular bilateral point-point transaction would map onto flows through the defined flow gates.

The flow gates are assumed to provide a sufficiently accurate representation of important constraints on transmission network operation and the PTDFs are assumed to provide a sufficiently accurate representation of how incremental point-point flows through the meshed transmission network map onto the much simpler flow gate model.

Moreover, it is assumed that there is sufficient linearity that bilateral transactions create flows that are additive through flow gates and that both the flow gates and PTDF coefficients associated with a bilateral transaction are reasonably stable.

Network losses are not included in the FG model and must be dealt with separately. Sub-transmission and distribution networks are considered only to the extent that they imply a need for additional flow gates.

I understand that the genesis of the FG model is the methodology used by NERC to relieve real-time transmission constraints, based on a "wheeling" model of power system operation. In this application, excellent information is available about the location of current operating constraints (flow gates) and measurements that allow accurate estimation of current PTDFs associated with "physical" bilateral trades. However these assumptions seem less reasonable in the forward market context envisaged in the FG model. There would not be a well-defined pattern of bilateral trades. Thus there would be considerable uncertainty about the location of future flow gates and the values of the associated PTDFs. Moreover it is not clear that participants would always have incentives to reveal accurate information about their intentions.

The LMP approach uses a more detailed network model than the FG approach but more detail does not always imply more accuracy so far as important aspects of market behaviour are concerned. For example, transient stability limits may not map well to main transmission network element flows because they may be strongly dependent on generator and load operating points and characteristics. Thus there can be ambiguity as to which network element(s) of a main transmission network to deem to be constrained when a transient stability limit is invoked. However the choice may have great commercial significance – for example an investment that would strengthen a particular network element deemed to be constrained might not relax the underlying transient stability limit.

Similar problems can arise in a sub-transmission network serving a particular load area, where low voltage levels following any one of a number of local network contingencies (or unexpected rapid load increases at any internal node) may be the limiting factor rather than flows on particular lines. Strengthening a particular line deemed to be constrained might not relax the underlying voltage constraint. Translating this problem to the LMP framework might require the creation of a sub-region in which all nodes were treated equally.

Significant approximations are made if a DC load flow model of a network is used for LMP calculations. On the other hand, if an AC load flow model is used, decisions must be taken about allowable nodal voltage ranges and the representation of reactive power control devices and their associated control strategies. Traditionally, nodal voltage limits have been set as technical constraints, however in the LMP approach these can have great commercial significance and affect nodal prices at surrounding nodes as well as at a particular node where the voltage limit had been reached.

An alternative approach to voltage issues that we have studied at UNSW is to incorporate voltage-value functions in bids and offers. However this concept has yet to be implemented in any practical market. It would require market participants to have a degree of sophistication that is probably unreasonable to expect in an initial market implementation. Other technical factors in LMP implementation include the representation of controllable network devices such as phase-changing transformers. Finally decisions must be made as to whether network contingencies should be considered and, if so, whether deterministic or probabilistic criteria should be employed.

LMP implementation must also consider commercial factors. Experimental electricity market simulations consistently demonstrate that adequate competition is required to achieve efficient market outcomes. To ensure efficient market outcomes in the presence of any network constraint would probably require four or more competitors at each end of each potentially constrained line. Furthermore, until active demand-side participation in spot markets is achieved, only generator participants can be counted. Such commercial considerations reduce the potential for LMP to be an economically efficient method of managing all network constraints. This is particularly true for sub-transmission and distribution network constraints, where "lumpy" network investment options should be compared with distributed generation or demand-side alternatives. Negotiation under regulatory supervision may then be a better approach.

Thus in practice, implementing the LMP approach involves approximations and matters of judgement that may have great commercial significance. However the use of more abstract network models such as flow gates involves problems and choices that are at least as difficult.

An alternative interpretation of the FG model is that the main transmission network can be represented as a series of relatively unconstrained regional networks (system control areas for example) connected by identifiable transmission corridors with limited capacity. It may be worth noting that the Australian National Electricity Market (NEM) currently uses a multi-region network model that has some similarities to this interpretation of the flow gate approach. However in the Australian NEM, marginal network losses are approximately represented both within and between regions and individual nodal prices are calculated. Thus the NEM design can be described as a hub and spoke approximation to LMP. NEM regions are defined such that any constraint in the main transmission network that occurs for more than 50 hours per year appears on the boundary between two regions. Intra-regional constraints are managed by other means unless they become sufficiently frequent to justify the formation of another market region.

The Australian market rules allow for the relocation of regional boundaries if the pattern of constraints changes and the intent is that further nodal detail will be implemented in the NEM as the market matures (in terms of market participant understanding, technology and effectiveness of financial instrument trading).

Factors that were important in adopting this evolving approach to market implementation include:

- Stability constraints that are not readily mapped to transmission network elements.
- Commercially significant losses in parts of the transmission network.
- A desire to implement real time pricing (while still avoidable) rather than ex-post pricing (as is currently done in "full nodal pricing"). This is to encourage short-term responsiveness by both supply- and demand-side participants. It is worth noting that a recent major review of

experience with the New Zealand market recommended the adoption of real-time pricing. This may have implications for their implementation of nodal pricing.

- A desire to promote competition for regulated network service providers through entrepreneurial action by generation, network and demand-side participants. A market-based approach to this problem requires efficient price discovery (and thus adequate competition) on either side of any network constraint included in the real-time spot market. Australian now has a market network service provider in operation providing arbitrage between two market regions.
- Retention by state governments of responsibility for retail market design and important aspects of distribution network regulation, with differing priorities and timetables for implementation.
- The need for an initial implementation that was politically acceptable and that would facilitate a smooth transition from the traditional industry technology portfolio and culture to a competitive industry technology portfolio and culture.

How does bilateral trading compare to simultaneous auction trading? When might each be appropriate?

Experiments of market behaviour regularly demonstrate that inefficient market outcomes will occur without adequate competition. Typically, four or more similarly sized participants are required to deliver competitive outcomes. Thus bilateral trading is unlikely to give the best outcomes unless all participants have low-cost access to alternative trading options. However participants sometimes have specific (non-commodity) products that they wish to trade bilaterally. In this situation, trading in a similar commodity product would provide a useful benchmark.

These lines of argument point to the value of auction-style trading when standardised commodities can be defined, particularly when there are time constraints and accurate volume information is important in determining price outcomes, as in a lossy and potentially constrained electricity network. Moreover, modern computing and communication technologies allow auctions to be conducted rapidly and at low cost even when a complex auction algorithm is involved.

In the context of competitive electricity industries, there are strong arguments for treating electrical energy as a commodity if a network model is to be included in a real-time market (e.g. proposed energy production or consumption for the next half-hour):

- Power systems operate according to physical laws and, in particular, energy flows between generators and loads according to network admittances. Commodity trading provides a better match to this situation rather than bilateral trading if network effects are to be included in the commercial model. In particular, wholesale electricity trading can then be characterised as commodity trading at one, several or many locations in a network.
- If the commodity market is to solve in real-time or ex-ante rather than after the event, network flows must be forecast to assess whether there will be binding network flow constraints, to estimate network losses and, if relevant, to estimate nodal voltages. The inherent non-linearity of electricity networks means that accurate forecasting of network flows requires accurate estimation of nodal injections and off-takes.
- This can be achieved efficiently and rapidly if energy-only bids and offers are resolved simultaneously for all market participants by means of an auction algorithm that contains a network model.
- The transparency and simplicity of an energy-only bid/offer process, coupled with computer implementation, provides a detailed audit trail for assessing the exercise of market power.

Forward trading in futures that attempt to directly predict future real-time spot market outcomes should use the same algorithm and network model as the real-time market. However the predictive power of such a futures market will depend strongly on the accuracy of participant predictions of their future spot market bids and offers. Participants who wish to hedge are motivated to do that.

Assuming that uncertainty increases with increasing forward projection, it would be appropriate to use a hub and spoke trading model for both real-time and futures markets. Short-projection futures markets would use the same network model as the spot market. However network detail would be successively reduced in longer term futures markets by falling back first to hubs and then to super-hubs alone. At each step in this process, there would be location-specific risks that the market could no longer manage. These might then be best traded bilaterally, possibly under regulatory supervision, noting that only local participants would be able to offer anything approaching a traditional "physical" contract. For example, a local distribution company could offer network access insurance.

Other specific risk management instruments, such as bilateral point-point futures contracts, could be constructed from a hub and spoke futures market model (although these may not be fully firm). For example, the inter-regional settlement residue auctions implemented in the Australian NEM provide access to (non-firm) revenues from the real-time market that can be used by a generator to underwrite a bilateral futures contract to a consumer located in another market region.

In the traditional utility industry, the term "physical contract" was often used to imply a guarantee of future delivery of electrical energy at a pre-determined price. A perfect guarantee could, of course, not be given due to the fallibility of the energy supply chain to the customer's premises. In practice, a physical contract implied a promise of priority with respect to both physical and commercial risks. In a commodity-style real-time market, the equivalent of a physical contract would be a combination of a futures contract and network access insurance, coupled with priority in avoiding load-shedding and possibly special measures to protect quality of supply at the point of connection.

The outcomes of the Australian NEM shows that it is possible to design a sufficiently competitive electricity industry around a real-time wholesale commodity market that incorporates an approximate model of the main transmission network (noting that high prices still occur during times of supply constraint). This in turn provides a basis for risk management that employs exchange-traded financial instruments, OTC trading and specific bilateral contracts. Such an approach combines the strengths of both auction and bilateral trading. It can also provide an equivalent of the traditional bilateral physical contract. Finally, this approach can also provide an efficient interface between the real-time market and power system operation.

What network-related risks can be successfully commercialised and how is this best done?

For the purposes of this discussion, risk will be considered as the likelihood of an unintended event combined with its consequences. Sometimes this is monetarised by multiplying a probability by a damage value, although both may be difficult to quantify.

In a competitive electricity industry, it is useful to categorise risk as either physical risk or commercial risk, where physical risk is associated with unintended consequences of power system operation and commercial risk is associated with unfavourable outcomes from commercial trading. An example of a physical risk would be a blackout following the failure of a large generator or distribution line. An example of a commercial risk would be lower than anticipated profits for a generator or higher than anticipated electricity costs for a consumer due to unexpected market price behaviour.

In power system jargon, the causal events associated with physical risks are known as contingencies, and a core objective of power system operation is to minimise both the probabilities of contingencies and their consequences. This leads to operating strategies such as security-constrained dispatch.

Clearly there are links between physical and commercial risk as the following examples illustrate:

- Excessive zeal in implementing security-constrained dispatch may restrict network utilisation to the extent that unfavourable commercial outcomes (such as those listed above) occur in an associated LMP market.
- Conversely, reluctance to take precautionary measures to reduce threats to power system security may exacerbate commercial risks. For example, it is likely that the six-week Auckland blackout could have been reduced or even largely avoided by early intervention to reduce the thermal stresses on the underground cables that eventually failed catastrophically. Instead, a small commercial risk was converted into a much larger one through what in hindsight were inappropriate operating decisions.
- It is often true that physical risks can be reduced by increasing expenditure on equipment purchase and on power system operation and maintenance. Thus reduced physical risk may come at a cost. Moreover, taking network equipment out of service for maintenance may directly induce increases in LMP market prices, by lowering network flow limits and making it more likely that they will become binding.

Introducing competition into an electricity industry may increase many physical risks because of pressures to reduce supply industry costs. However the most direct change is with respect to customer risks associated with loss of supply or poor supply quality. Under the traditional regulatory compact, customers accepted regulator-supervised supply standards in return for regulated tariffs. Except for extreme events, traditional utilities were judged by their average performance by customer class or region. In a competitive market with individually negotiated contracts, customers expect direct accountability for the supply availability and quality that they experience. Moreover, customer expectations of availability and quality are rising with increasing value being derived from electrical technology and increasing equipment sensitivity to poor availability or quality. In response, demand-side options such as uninterruptible power supplies and stand-by generators are becoming more common.

In summary, the risks associated with unreliable or poor quality supply are growing and so is the interest in managing these risks commercially.

In most power systems, distribution and sub-transmission network events dominate the physical risks that customers experience from unreliable or poor quality supply. Inadequate generation capacity may sometimes be an important risk factor, particularly during summer or winter peak load conditions. Load-shedding or voltage reduction may be appropriate operator responses to some contingencies, in which case preferential treatment may be given to certain customers.

Distribution and sub-transmission networks are usually on the consumer side of wholesale electricity markets and thus the related consumer risks are matters for distribution industry regulators or retail market design rather than wholesale market design. Customer contracts or commercial law may provide some financial compensation to customers if they experience unreliable or poor quality supply.

A number of steps might be taken to commercialise the physical risks associated with transmission networks in wholesale electricity market design, including the following:

- Network service providers could be given commercial incentives to avoid network maintenance outages during high-price periods
- Network service providers could be required to offer generators and consumers “firm access contracts” that provide financial compensation if network access is constrained.

- Real-time wholesale market prices could be set to their price ceiling if load is about to be shed (this can provide compensation to those consumers holding futures contracts and encourage others with futures contracts to voluntarily reduce demand).

Is the preferred implementation in the Western System likely to differ significantly from that on the East Coast?

Differences might arise for a number of reasons including the following:

- Power system operating constraints might map more accurately to specific network elements in one case than the other.
- Traditional industry operating protocols and State-level regulatory policies may differ sufficiently to justify a different initial implementation of wholesale competition even if the long-term goal is similar.

General observations and conclusions

Electricity industry restructuring is a cultural process and theoretical analysis can only provide a guide not a detailed prescription. In particular, theoretical analysis is more useful in defining a preferred end-point than in choosing a transition path in a process that is likely to take a decade or more to complete. Having said that, I will venture the following opinions:

- A key feature of any wholesale electricity trading framework should be an efficient real-time (eg. half-hour ahead) commodity market that incorporates a network model of appropriate detail.
- The Balkanised nature of transmission networks in the USA means that there are significant transmission flow constraints that should be modelled in wholesale electricity markets. However these may not always map well to individual network elements.
- It may be worthwhile exploring hybrid trading models that contain features of both FG and LMP approaches.
- Risk management should be based on financial instrument trading rather than traditional "physical" contracts. It should combine auction-style futures trading with more specialised bilateral trading.

The following papers provide more background on the Australian implementation of electricity industry restructuring:

H R Outhred and R J Kaye, "Incorporating Network Effects in a Competitive Electricity Industry: An Australian Perspective", Chapter 9 in M Einhorn and R Siddiqi (eds), *Electricity Transmission Pricing and Technology,* Kluwer Academic Publishers, 1996, pp 207-228.

H R Outhred, "A Review of Electricity Industry Restructuring in Australia", *Electric Power Systems Research*, 44 (1998), 15-25.

Epilogue, October 2000

The debate between the proponents of Flowgates and Locational Marginal Pricing has continued since the MEET conference and shows only limited signs of convergence. This is not surprising, as it is not a simple either-or choice. In my view, electricity market design requires compromise choices between a range of design criteria that should be made in a broader context than that adopted for the "MEET debate". I believe that the set of questions defined above remain both relevant and yet to be fully addressed by proponents on either side of the debate.

Market design can be approached as an evolutionary process that may start from a range of initial implementations. As an (imperfect) example of this process, readers may wish to consider the following two references. The first of these references outlines the strengths and weaknesses of network representation in the Australian wholesale National Electricity Market (NEM) as of 1998 and proposes a number of improvements. The second reference is the current official proposal by the National Electricity Code Administrator (NECA) for improving network representation in the NEM. It largely adopts the strategy suggested in the first reference, recommending a staged implementation providing greater detail and other refinements for the existing hub-and-spoke model rather than (for example) the adoption of "full nodal pricing" because its net benefits are regarded as "arguable":

> "Without a firm hedging mechanism, which would be difficult if not impossible to devise, it [full nodal pricing] would expose participants to largely illiquid markets and therefore unacceptable risks. Moreover, nodal pricing that would allow the co-optimised despatch of active and reactive power is currently incompatible with five-minute despatch and pricing" (NECA Summary Draft Report, October 2000).

Rules for network pricing and regulation are being refined in parallel with the changes to network representation in the NEM. These refinements are designed to improve contestability of network augmentation by distributed resources. Information about these proposals is also available from the NECA web site (www.neca.com.au).

References to Epilogue:

H R Outhred, "Network Pricing - Proposals in the National Electricity Code", Australian Competition and Consumer Commission / University of Melbourne, Electricity Transmission Network Pricing Conference, 14-15 December 1998.

National Electricity Code Administrator (NECA), "The Scope for Integrating the Energy Market and Network Services", Draft Report (Summary Report plus Vols 1-4), October 2000 (www.neca.com.au – what's new?)