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Electricity transmission pricing: an international comparison

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This paper discusses six criteria for electricity transmission prices, concerned with economic efficiency and political implementation. Prices should signal the costs of using the transmission system, but this may conflict with the need to produce a clear message that users can understand, given the complexity of transmission costs. Changes to transmission prices are also likely to produce winners and losers, and so political constraints may impede cost-reflective changes. This paper draws out some of these themes, using examples from eight studies of transmission pricing systems, written by members of a working group of the Energy Modeling Forum. © 1997 Elsevier Science Ltd. All rights reserved.

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Introduction

In a market economy, prices have two functions. The first is to act as a signal of relative costs. If the price of good A is twice the price of good B, then any buyer has to give up twice as much of any alternative goods to acquire a unit of good A, as for a unit of good B. We should be able to infer that all those who choose good A in preference to good B value it at least twice as highly. Those who place a lower value on good A will not purchase it. A 'social planner' would need a vast amount of information in order to allocate a fixed amount of good A to those who valued it most highly. In the market mechanism, buyers signal the relevant information in their willingness (or not) to pay a given price. Strict assumptions are required to 'prove' that the process ends with the good distributed in an optimal manner, but experience tends to show the problems involved with any other way of distributing scarce goods.

The role of prices as signals becomes even more useful when the quantities of goods available are not fixed, and resources must be allocated to produce the goods. Prices can now signal the relative cost of producing a little more of each good. Good A may be twice the price of good B because it requires twice as many hours of labour to produce at the margin. An extra unit of good A should only be produced if there is a potential user who values it twice as highly as the alternative, a unit of good B. If a purchaser can be found, this is exactly what their willingness to pay the higher price implies. Prices can aggregate information about production costs: to build a car may require a tonne of various materials, a large factory, and several hundred hours of labour, while a bicycle might be built in fifty hours in a workshop, with 20 kg of materials. A social planner would need to know this, and how each material was produced, before deciding how many cars and bicycles should be made. In an efficient market, the price of the good is equal to the sum of the cost of each of the inputs required, and decisions are decentralised. Consumers buy bicycles if the price offers good value compared to the price of cars, while producers build bicycles if they can obtain a price at least as great as the marginal cost of the materials and labour involved.

The second function of prices is in distribution—they determine how many resources are transferred when a transaction takes place. This is vital to their function as signals—the messages are only believable if consumers and producers are forced to 'put their money where their mouth is.' It is also unfortunate. Agents have an incentive to distort prices in their favour—buyers would like to reduce prices, and sellers to raise them. A monopolist might attempt to raise the price of good A to 3 times that of good B, and would earn large profits from doing so. Some people would stop buying good A and start to buy good B. They would still value good A more than twice as highly as good B, and it would still only take twice as much time to produce each unit, and so this change in economic activity would leave society worse off. If they are too far from costs, prices become a hindrance rather than a help to an economy.

A perfectly competitive market produces an optimal outcome because all agents realise that they cannot affect prices by their own decisions, and so respond to them as

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signals, rather than attempting to change their distributional consequences. A monopolist knows that its pricing decisions can have distributional consequences, and so its price signals are distorted. One answer to this is an active competition policy to prevent monopolies being formed, and to break up existing monopolies, but some industries are natural monopolies where competition is inappropriate. In those cases, it has become normal for the government to influence prices, usually through a regulator, in the hope that it can obtain a better outcome than an unregulated monopoly.

Twenty years ago, electricity transmission pricing was a theoretical, rather than a practical, subject. Transmission and generation were usually vertically integrated, and while the integrated utilities might sell power to local distributors, and exchange power with their neighbours, there was little need for a formal system of transmission prices. Over the last 20 years, however, transmission and generation have been separated in many countries, and so transmission prices are used in real transactions. Electricity regulators must approve these prices, conscious both of their need to send appropriate signals, and of their distributional consequences.

Six principles for transmission pricing

A discussion among members of a working group organised by the Energy Modeling Forum of Stanford University on electricity restructuring and competition led to a list of six principles which should be followed when designing electricity transmission prices. The prices should:

1. promote the efficient day-to-day operation of the bulk power market;
2. signal locational advantages for investment in generation and demand;
3. signal the need for investment in the transmission system;
4. compensate the owners of existing transmission assets;
5. be simple and transparent; and
6. be politically implementable.

The first three objectives are obviously concerned with signalling, but so is the fifth—there is no point in sending a signal so complex that the recipients cannot understand and react to it. The distributional aspect of prices comes to the front in objectives 4 and 6. An alternative way of looking at the principles is that the first is concerned with short-term economic efficiency, numbers 2–4 with long-term efficiency, and 5 and 6 with implementation.

The articles in this symposium assess eight systems of transmission pricing against these principles. Each was written by a member of the Energy Modeling Forum working group, and the studies were discussed at the Forum's meeting in January 1997. The purpose of this introduction is to look at the principles in more detail, and to 'compare and contrast' the individual studies.

The systems range from the 30 TWh of New Zealand (with 3.5 million people) to the 777 TWh of Japan (with 125 million). Hydro-electric power provides practically all the generation in Norway, and 75% in New Zealand, while the other systems are largely thermal. There is a significant transmission constraint between the North and South Islands of New Zealand, while New England has a dense transmission system with few internal constraints under normal operation. Four of the studies look at systems where there is already an independent transmission company (England and Wales, New Zealand, Norway, and the South American countries discussed by Raineri and Rudnick). In the other 4 systems (California, Japan, New England and Texas), vertically integrated utilities predominate, although proposals for restructuring and competition in the US call for the establishment of independent system operators.

The paper by Hsu discusses the costs of electricity transmission, and in particular the marginal costs. Electricity transmission is an unusual 'product', because the marginal costs at one location depend on what is happening elsewhere on the transmission system. Some power is lost when electricity is transmitted from power stations to consumers, but if generation is added near demand, then the power flows on the system will decrease, and losses will fall, implying a negative marginal cost. Many systems suffer from transmission constraints which prevent relatively cheap generators from producing. More expensive stations must operate instead, in order to prevent some lines becoming overloaded. Adding generation at the right place can reduce these constraints and result in significant cost savings, while generation which worsens a constraint can be very costly. One approach to transmission pricing, developed by Schweppe *et al.* (1988) and known as 'spot pricing', attempts to base prices on these real-time marginal costs. Hsu gives several examples of marginal cost and the corresponding spot prices.

Some recently adopted transmission pricing systems are based upon spot prices, but most of those discussed in this symposium use other pricing rules. The paper by Ilic *et al.* applies 3 pricing rules for bulk power transfers to hypothetical (but typical) transactions on a detailed model of the New England system, and shows that the rules produce very different prices. Since a different set of prices is likely to lead to a different outcome, this example shows the importance of choosing a sensible pricing rule. The rest of this paper discusses the 6 criteria for transmission prices, and shows how they have affected some of the pricing rules in our 8 systems.

Promoting the efficient day-to-day operation of the bulk power market

All the generators on a power system must be coordinated, or the system will quickly break down. At the most basic level, the job of the coordinator(s) is to ensure that generation is equal to demand at all times, and that the system has sufficient spare capacity to cope with the sudden failure of any generator or transmission circuit. Subject to these operational constraints, economic efficiency requires the coordinator to meet demand at the lowest cost possible: to perform an economic despatch. If all the generation was at a single node, this would simply require the coordinator to schedule generators with low marginal costs in preference to those with high marginal costs[1].

Once generation is dispersed across the transmission system, economic despatch must take the marginal costs of transmission into account. These are of 2 kinds—the actual cost of system losses, and the opportunity cost of transmission constraints. Transmission losses are an actual cost in that less electricity can be consumed than is generated, and somebody must pay for the difference. Constraints mean that a cheap generator must be replaced with a more expensive one, although the cost involved is only apparent when the cost of the constrained despatch is compared with the cost of an unconstrained system. Both costs must be taken into account in an optimal despatch. The relative importance of losses and of constraints depends upon the individual system: in Norway, losses were much more important than constraints when the markets were first restructured, whereas transmission constraints are given more attention in the US. There are fears that transmission constraints could split the planned Californian market into two halves, reducing the extent of competition in each, whenever the lines between the north and the south of the State are heavily loaded.

The marginal costs of losses and constraints should be added to each generator's operating cost when deciding which stations to run. These will be much greater than the corresponding average costs. Transmission losses are proportional to the square of the current flowing down a line, so that the marginal loss is twice the average loss. A constraint may only bind for the last few MW of generation, so that the absolute saving from releasing the constraint (the average opportunity cost) is small, although the marginal cost for each of those MW is large. One implication of this is that marginal cost prices will produce revenues which are greater than the direct cost of losses and constraints, and can provide a surplus towards the fixed cost of transmission[2].

There are at least three approaches to these short-run transmission costs. The first is to ignore them, and to create despatch rules that treat the system as if all the generation was at a single point. If there are constraints on the system, the real-time despatch cannot follow the rules exactly, and the coordinator(s) will have to change the despatch to meet the constraints. Such real-time alterations are unlikely to be optimal. The coordinator may be required to bear some or all of the costs of constraint management, in order to provide an incentive to minimise these costs. Chile has adopted a system of this kind—the despatch is based upon a single node system in which all generators are required to bid their regulated marginal cost. England and Wales also based its despatch on an unconstrained system with no losses, but left generators free to choose their own bids. The advantage of such a system is its relative simplicity: the disadvantages are that the despatch will be badly suboptimal if transmission losses are significant, or the optimal constrained despatch is not close to the unconstrained solution.

A second approach is for the coordinator to act as if all the generation on the system was at the same place, but to impose transmission charges which reflect the marginal costs of transmission. In a competitive market, generators would then set their bids equal to their marginal generation costs and their transmission charge. The coordinator would set a systemwide price, but the net price to generators would vary by location. In Norway, there was a single nationwide energy price, but each generator had to pay a transmission charge dependent upon a loss factor (based on marginal losses) which varied by region and season. In Texas, a matrix of quasi-marginal loss factors, calculated from specified 'pro-forma' load flows, is used to charge for 'unplanned' transmission services. This is a straightforward way of sending approximate cost messages, but if actual costs are unpredictable, the cost messages will inevitably be inaccurate. This might imply that this method would be less appropriate for a system with significant transmission constraints[3]. In Texas, utilities must book 'planned' transmission service to meet their peak demands (with a 15% margin), but may also ask for 'unplanned' transmission service. If their request for unplanned service can be accommodated, the utility will only have to pay a small fee per MWh, plus an approximation to the marginal losses caused by the transaction (using loss matrices based on the peak planned flows). If the system is constrained (which may often be the case) the requested transaction cannot be carried out. This seems to be a good compromise between simplicity in charging, and reflecting costs—the simple charge is only applied to the unconstrained system, when it does reflect costs.

The third approach is to base the despatch upon an explicit system model which includes losses and constraints. The coordinator receives bids from the generators, which 'should' equal their marginal generation costs, and runs the system model to produce an operating schedule and spot prices. Generators are paid the spot price at their node, which includes the marginal cost of losses and constraints. Such a system has recently been introduced in New Zealand. It should lead to a fully optimal despatch, unless generators can manipulate their bids in an imperfectly competitive market. California is planning a system which is simpler in one respect (because the state will be divided into only 2 zones), but more complicated in others, because many agents will be allowed to act as Schedule Coordinators, planning despatch to meet the expected load of their customers. They will send their planned despatch to an Independent System Operator, which will suggest a feasible redespatch, taking account of transmission constraints, if their plans are infeasible. The Independent System Operator will attempt to minimise the cost of this (advisory) redespatch, and there will be a (potentially) separate bid-based price in each zone to signal costs.

Once the approach for charging generators has been chosen, the prices paid by consumers must also be considered. Transmission costs have just been expressed in terms of an optimal despatch, but they can also be seen as the cost of meeting demand at each point on the network. If consumers in an area with a high marginal cost do not face a high price for electricity, their demand is likely to be excessive—they value their electricity consumption less, at the margin, than the resources used to allow it. Similarly, consumers in an area with low marginal costs could be encouraged to increase their demand, with relatively lower prices. The theory of spot pricing suggests that generation and demand should face the same price at each node. (In practice, this would tend not to raise enough revenue, and the prices paid by consumers would have to be increased. If the same increase was applied at each node, the geographical signals would remain).

New Zealand has adopted this approach, with equal nodal charges for generation and demand. At one stage, California considered plans to implement geographical spot pricing for generation, but to charge the same price to all consumers. The present plan is for both generators and consumers to face the zonal prices, which are less likely than nodal prices to reach extreme levels. Other systems, with less sophisticated pricing for generation, have tended not to differentiate the energy prices paid by consumers. If prices have not been differentiated in the past, it is likely to be politically difficult to introduce changes. A further, economic, reason for not differentiating prices could be that most consumers are unlikely to respond to real-time price signals, and so the cost of sending them is greater than the benefit from receiving them. One disadvantage is that generators in a 'low price' region might attempt to opt out of the central pricing system, offering a discount to local consumers who would prefer not to pay the (higher) average price. In high priced regions, however, it may be possible to make arrangements with some consumers who are able to manage their loads in real time. If their 'normal load', paid for at the national price, can be established, they can be paid at the local price for reducing load below this level when required, so that they face the right signal at the margin.

Signalling locational advantages for investment in generation and demand

Short-term scheduling decisions can affect the cost of transmission, but the most important factor is the location of generation and demand, and the system coordinator can do little about this in the short term. Over the longer term, however, it may be possible to influence the location of power stations, and of energy-intensive industry. If generation and demand are sited closer together, the costs of transmission will be lower. This does not mean that it is always best to site generation close to demand—it can be cheaper to transport electricity than fuel, and hydro-electric resources, for example, cannot be moved—but the price signal should be sent, to ensure that the cost of transmission is taken into account when deciding where to locate a generator. Similarly, few customers may change their decisions about where to locate their demand if they face their specific transmission costs, but if they are given an incentive to locate where electricity costs are lower, we can at least be sure that it was taken into account.

There may be no need for a separate signal for investment decisions if the prices paid and received for energy vary with the cost of transmission. If generators are paid spot prices which incorporate the short-run marginal costs of transmission, then they should have the right investment incentives. This applies to a small project (which would not change power flows significantly) in an optimised system (where any additional transmission investment would just pay for itself in reduced losses). The main exception to this is for large projects, which could change power flows (and costs) significantly, and could also require heavy investment. Decisions on those projects should not be based on present spot prices alone, but include the projected systemwide impact of the project. There is a further risk that the short-run cost might change over time, due to developments elsewhere on the system. Hogan (1992) has proposed transmission congestion contracts which get round this problem by allowing users to hedge the price differentials between nodes, and therefore base their decisions on stable prices.

Most of the systems which do not use their energy prices to send signals about the cost of transmission have separate transmission prices which do send some signals.

In Japan, independent generators have to pay a per kWh charge based on the costs of the transmission system, together with their share of losses. These charges may send appropriate signals for investment, even though Asano suggests that since they do not reflect day-to-day conditions, they cannot help with the short-term efficiency of the system. Transmission users in England and Wales face regionally differentiated charges per MW of peak demand or generating capacity, which are intended to reflect the National Grid Company's marginal investment cost of providing sufficient capacity. Generators have a significant incentive to locate in the south and west of England, where the load exceeds the local generation, as a result of these charges. Even so, the simplified algorithm used to calculate the charges may produce differentials which are smaller than the true difference in costs involved.

Signalling the need for investment in the transmission system

Transmission prices can also be used to signal the need for new investment in the transmission system—indeed, transmission investment is often an alternative to moving a planned investment in generation or on the demand side. Prices will only produce a useful signal, however, if they are based on marginal costs. If the marginal cost at two adjacent nodes is very different, that is likely to imply that the flow between them affects a transmission link which is not strong enough. In an unconstrained system, the cost depends solely upon losses, which are closely estimated by the square of the power flow times the resistance. Extra investment could reduce the resistance, and hence the losses. Similarly, the opportunity cost of congestion comes from the fact that cheap generation cannot be accepted onto the system because it runs the risk of overloading a transmission line, and so more expensive stations must be scheduled instead. If the congestion could be relieved, then it becomes possible to increase output from the cheap station, and reduce the cost of generation.

There are three potential problems in using high price differentials as the signal for investment in the transmission system. First, most investments are lumpy, and will lead to significant changes in flows, and hence in prices. An investment may allow an extra 100 MW to flow from a low price to a high price node, and the cost of the investment would be covered by the existing price differential multiplied by the 100 MW flow. Once the investment is made, however, and the flow takes place, the price differential is largely eroded. The investment was correctly justified by the *ex ante* prices, but would make a loss at the ex post prices, unless the investors could 'lock in' to the *ex ante* prices. Transmission congestion contracts have been proposed as a means of locking in to high price differentials and allowing investment to be financed.

The second problem occurs when transmission ownership and investment is divided among several companies, and the actions of one could create significant externalities. The cheapest way to increase the flow along one congested link may be to build a line between two nodes on another company's system. This would not be economic for that company unless a side payment can be arranged. There are also negative externalities: increasing the capacity of one link may reduce the capacity of others. Bushnell and Stoft (forthcoming) demonstrate how transmission congestion contracts can internalise both positive and negative externalities: the investor is given any set of contracts, which, when combined with any existing contracts, is consistent with the network's new capacity[4].

The third problem is that the transmission owner is likely to earn significant amounts of revenue from marginal cost pricing in the presence of heavily loaded lines which cause constraints or high losses. This could create a perverse incentive for the system owner—an inadequate system would produce greater revenues and lower costs (for the transmission owner) than an optimal one. In practice, revenues from marginal cost pricing are almost always 'topped up' to produce an adequate total revenue for the system owner (see the following objective). As long as the total revenue, rather than the 'top up', is regulated, then the transmission owner will have no incentive to raise money from bottlenecks. Most regulatory systems will allow the costs of alleviating the bottleneck to be passed on in prices, ensuring that the transmission owners have no reason not to invest when additional capacity is required[5].

In practice, most of the industries studied here have not used prices to guide their investment decisions. In Japan, for example, the transmission system is owned by the regional utilities, which are responsible for building and maintaining an efficient and economical power system. Transmission investment decisions are internal to each company, and normally based upon its own needs. The National Grid Company in England and Wales has a similar duty, although it is also required to facilitate competition and meet users' reasonable requests for connection to the system. How it does so is a matter for the company.

In New Zealand, however, transmission prices are used to guide investment decisions. Trans Power, a state-owned utility, is responsible for operating the transmission system, and for planning expansions. Electricity spot prices in New Zealand are equal to nodal marginal costs, and system expansions are justified if the difference in prices with and without a scheme equals the cost of the scheme. The market-based rule used by the industry is that investment should only go ahead if a coalition of users willing to pay for it can be found. Read reports that these principles have been followed for some years and applied to a number of projects, although it was recognised that Trans Power might have to part-finance schemes 'on behalf of dispersed stake holders'.

Compensating the owners of existing transmission assets

It should not be surprising that this objective has figured heavily in the design of transmission pricing systems—existing participants are invariably involved in the negotiations which create a new system, and they are concerned about their future revenues. In some countries, it could be unconstitutional to design a regulatory system that would not give fair compensation to the owners of transmission assets. Even where the legal system might allow the introduction of transmission pricing which did not promise adequate returns to existing assets, this would be undesirable. Future investment depends upon a credible promise that those who finance it will receive an appropriate return on their investment. If potential investors see the effective expropriation of existing assets, they will be unwilling to invest in the future. Spiller and Martorel (1996) suggest that when governments cannot commit themselves to give adequate compensation to the owners of existing assets, private ownership will be impossible. They contrast the transparent regulation of the Chilean electricity industry, which was successfully privatised, with the public ownership which was the 'default mode' in Argentina, Brazil, and Uruguay during the 1980s, where regulation was politicised and prices often failed to keep up with inflation.

The overall level of transmission charges is generally set to allow the transmission owners to recover a regulated level of revenue. In Texas, for example, this is equal to their embedded costs. Price controls are used in England and Wales, but an asset base is included in the calculations when these are reset, and this is generally related to the companies' market value at privatisation (which is typically below the replacement cost of their assets).

The allowed revenue is typically much greater than the amount which would be recovered from the 'signalling' prices. In Norway, for example, loss-based energy tariffs covered only 25% of the grid's costs in 1995. A further 21% came from systemwide charges on peak consumption and generating capacity, and 51% from a charge on net exchanges with the central grid system in its peak hour[6]. In England and Wales, 'transport' tariffs based on a model of marginal investment costs were expected to raise just over 20% of the grid's allowed revenue. A further 70% was justified as the cost of system security, while the remaining 10% of the grid's allowed revenue was simply claimed as a 'residual.' This would be achieved by raising each generation charge by, say, £2/kW, while the charges on peak demand would be increased by, say, £8/kW.

While the additional revenue requirements are often recovered from all transmission users, generators in Chile are only charged for the assets which they are deemed to use. The 'area of influence' corresponds to the lines and substations which are significantly affected by the generator's output, using load flow models. In Argentina and Bolivia, distribution companies also make payments on a similar basis.

The problem with recovering historic costs from transmission prices which are intended to reflect marginal costs is that the cost recovery component can dwarf the marginal cost messages. For some years, New Zealand attempted to get round this by calculating cost allocations in a similar way to the South American systems just described, but then basing charges on a 10-year rolling average of the past cost allocations. The hope was that this would mute the effect of current decisions on any one year's charges, and mean that the charges would not distort the marginal cost signals from the spot prices. A new system has been introduced in which users will pay for (negotiated) blocks of capacity: if these payments are seen as fixed, then the marginal signals should not be distorted.

Simplicity and transparency

If transmission prices are to send useful signals, it is important that they are understandable. If users do not know how much they are paying for transmission, they cannot change their actions in response to the charges. It can also be helpful (not least in political terms) for users to know how price differentials are calculated, and why. At the same time, if prices are to reflect marginal costs, which are complicated, they cannot be overly simple. Some countries have chosen to send more accurate cost messages, and accepted that their price system must be relatively complex, while others have deliberately simplified things.

The 'contract path' pricing used in New England (and other systems) until the recent past is an extreme case of simplicity. Each transmission-owning utility has a 'postage stamp' wheeling charge per kW year. This might be obtained by dividing its costs of transmission by its peak demand. Utilities which wished to exchange power would have to negotiate a contract path across any intervening systems, and pay each of those systems its wheeling charge. In practice, the transaction would usually affect power flows on other utilities' systems, but these would neither receive payments nor make them (in the event that their costs were reduced by the transaction).

The use of zones rather than nodes for pricing purposes is a common simplification. In England and Wales, the National Grid Company is about to change its zones for demand charges so that they coincide with the areas served by the 12 Regional Electricity Companies, even though it will be using 16 zones to reflect its costs in its generation charges. NGC was also concerned about 'transparency', which it interpreted to imply the use of a very simple model when calculating the load flows on which its prices are based, and made the data involved available to interested parties. Others, however, see a distinction between simplicity and transparency; the New Zealand system is transparent in the sense that it is based on a specific, auditable, model, although that does not mean that every market participant understands it[7].

Political implementation

It is possible to give an 'economic' benefit that comes from each of the first five principles. Sending signals about costs leads to efficient decisions, compensating investors encourages them to invest in the future, and choosing simple prices helps ensure that the signals are acted upon. It is hard to think of a corresponding benefit from the sixth principle, but it is of great importance. To put it bluntly, if too many influential agents are likely to lose from a proposed pricing system, they will make sure that it will never be implemented.

Most 'traditional' transmission pricing systems tended to understate cost differentials. The newer schemes discussed in this symposium are likely to align prices more closely to costs, and hence to increase the charges for some users. These users are likely to object. Since most of the schemes discussed here have been implemented, the losers' objections must have been overruled. The schemes therefore meet the political constraint, but we can sometimes see its impact. In England and Wales, for example, increases in transmission charges were capped, so that the changes had to be phased in over four years. In California, two local constraints have been ignored when designating zones for the new market, so that even though generators within these areas (San Francisco and Humboldt) may receive high prices, charges to consumers are likely to be uniform within each utility's area, as at present. (Existing differentials between utilities are likely to be preserved for the time being, however.) There is an unresolved debate as to how far utilities which are not 'self-sufficient' and import power from neighbouring areas should have to bear part of the cost of those areas' transmission systems.

Texas has recently adopted a transmission pricing system in which prices can have a perverse relationship to costs. A statewide 'postage stamp' will recover 70% of the costs of the transmission system, but the remaining 30% are to be paid for on a 'vector absolute megawatt-mile' basis. A system model will be used to calculate the impact of each planned transmission service, measuring the absolute value of the change in the flow over a line, multiplied by its length in miles. A long-distance transaction which increases the flows on a large number of lines will have to pay a large fee, even if the lines are not heavily loaded. In fact, to send power in the opposite direction, which would actually decrease power flows and costs, would involve exactly the same charge. Sending price signals of this kind is unlikely to reduce the system's costs. The main message seems to be to discourage long-distance transmission, even when it would reduce costs. This would be in the political interests of a utility that did not want to face competition and sought to increase the costs of any company attempting to sell into its 'patch', but it seems surprising that the system was actually adopted.

Conclusion

This introduction has attempted to draw out some common themes from the papers which make up the symposium. I have not attempted to summarise the papers—the diversity of systems is too rich. Some have tried to send sophisticated cost messages, while others are content to collect their allowed revenues while sending approximate signals about their costs. None of the authors claims that they have 'the' right answer, and it probably does not exist. All we can do is learn from each others' experience, and hope for incremental improvements.

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[1]'Simply' is perhaps something of a misnomer, given the dynamic constraints of power plant operation. Some stations are cheap to start but expensive to run, while others may have minimum intervals between startup and shutdown, or vice versa. The despatch algorithm must include all of these constraints.

[2]In practice, this surplus will only cover part of those fixed costs, so that other charges will have to be added to marginal cost prices in order to recover the total costs of the transmission system.

[3]This might still be better than the first system, however, and could be appropriate for a constraint whose extent and cost were sufficiently predictable.

[4]The feasible allocation rule can force investors to take contracts to offset any reduction in the possible flow across constrained links, and hence internalises any negative externality.

[5]In fact, the ability to pass on the costs, plus a profit margin, means that transmission owners may wish to exaggerate the amount of investment needed in their system—the Averch–Johnson effect.

[6]There are proposals to collect all of this revenue (around 70% of the total) from systemwide charges on generation capacity and gross demand at the peak.

[7]Price systems do not need to be understood by everyone if they are to

work, of course, as long as people can observe the prices which are relevant to them, and respond appropriately.

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