A Capacity Rights Regime for the HVDC Link

Report to Rio Tinto Alcan New Zealand Ltd

22 March 2010

About NZIER

NZIER is a specialist consulting firm that uses applied economic research and analysis to provide a wide range of strategic advice to clients in the public and private sectors, throughout New Zealand and Australia, and further afield.

NZIER is also known for its long-established *Quarterly Survey of Business Opinion* and *Quarterly Predictions*.

Our aim is to be the premier centre of applied economic research in New Zealand. We pride ourselves on our reputation for independence and delivering quality analysis in the right form, and at the right time, for our clients. We ensure quality through teamwork on individual projects, critical review at internal seminars, and by peer review at various stages through a project by a senior staff member otherwise not involved in the project.

NZIER was established in 1958.

Contents

1. Background

The charging for the High Voltage Direct Current (HVDC) link between the electricity transmission grids in the North and South Islands has long been controversial in New Zealand. Beginning when it was established in 1998, Meridian Energy Ltd (Meridian) refused to pay the charges for the link imposed by Transpower New Zealand Ltd (Transpower). This eventually led to litigation and a judgement in favour of Meridian. The upshot was legislation in 2001 providing Transpower with power to enforce payment of its charges, including the HVDC charge. This power was subsequently renewed and lasted until the Electricity Commission (the Commission) had approved a transmission pricing methodology and this methodology came into force.

Meridian and Contact Energy Ltd successfully sought a judicial review of the HVDC charging element of the Commission's initial transmission pricing methodology. The Commission was required to reconsider its proposed methodology and developed an alternative as a result. But this was even less satisfactory in the opinion of South Island generators as it required them to pay for both the existing HVDC link and any upgrades, whereas the initial methodology had required them to pay for the existing HVDC link only.

More recently, the Electricity Sector CEOs' Forum initiated a review of the current transmission pricing methodology. Subsequently, the Commission has started its own review. While the focus of both reviews is on the adequacy with which use and locational signals are conveyed to decision makers, HVDC charges are a prominent element in both.

2. Objections to current HVDC charges

2.1 South Island generators not only beneficiaries

The objections to the current HVDC charging regime have largely, but not exclusively, come from generators with plant in the South Island and their advisors. In brief, their principal complaint is that they are not the only significant beneficiaries of the link but they are the only parties required to pay for it, and this they allege is unfair. They point to North Island load being beneficiaries of the usual south-north flows on the link and to the increasing level and frequency of north-south flows, which benefit South Island consumers by improving their security of supply, especially in dry hydrological conditions. Supporters of the current regime argue that without the prior use of water in the South Island to generate electricity sent to the North Island there would be little or no requirement for north-south flows, even in dry hydrological years.[1]

---

[1] For an independent argument along these lines see NERA, *New Zealand Transmission Pricing Project: A Report to the New Zealand Electricity Industry Steering Group*, August 2009, pp. 57-9. Hereinafter referred to as the NERA 2009 Report.

2.2 Asymmetric investment incentives

There are a number of further grounds put forward as objections to the current regime. Firstly, it is claimed the current regime favours Meridian to be the provider of increased generation capacity in the South Island, to the detriment of other potential providers and with a negative effect on the efficiency of investment. The argument is that Meridian is the largest existing South Island generator by a wide margin. As a result, it picks up the lion's share of the total HVDC link charges under the current regime and, given that the total charge is fixed, Meridian faces a lower incremental cost than any other provider if it expands South Island electricity output.[2]

This argument fails to account properly for Meridian's costs should it decide to increase output in the South Island rather than allow some other party to do so. If Meridian expands its South Island output, it not only incurs the increment in HVDC charges due to its share of South Island output rising, it also forgoes the decrease in its charges that would have occurred had output been expanded by another party. It is not hard to show that the consequences of expanding output in the South Island for HVDC charges is the same for Meridian as for any other provider, as long as the comparison is on the basis of opportunity costs; the appropriate costs to consider in economics are always the opportunity costs.

2.3 Inefficient operating incentives

Secondly, it is claimed the current regime inefficiently discourages South Island generators from operating their existing plant at full capacity because the HVDC charge is based on the highest average of the 12 highest peak injections into the grid over the current and four preceding pricing years. This alleged incentive to constrain output has been shown to be unlikely to be of any material effect, in practice, however.[3]

2.4 Discourages peaking plant inefficiently

Thirdly, it is claimed the current regime discourages the development of peaking capacity in the South Island because a peaker has to pay for the link on the basis of its average 12 highest peak loads, even though the peaker will not be producing more than a small percentage of the time. The HVDC charge is a significant financial impost relative to the output produced by a peaker in the periods it actually operates. Peakers located in the North Island are not liable to such a charge. The extent to which peaking capacity is required in the South Island in the short to medium term is debateable, however, and if there is no need for peaking capacity in the South Island this argument is a moot point.[4]

[2] See NERA 2009 Report, pp. 63-4.

[3] See NERA 2009 Report, pp. 61-2.

[4] See NERA 2009 Report, pp.62-3

2.5 Inefficient embedding of generators

Finally, it is claimed the current regime encourages South Island generators to be embedded in local networks even when it would be more efficient to be connected directly to the grid, in the absence of the HVDC charge.[5] The rationale is that the HVDC charge is paid only for generators directly connected to the grid and those connected to a local network that is connected to the grid, if the generator "has (directly or indirectly) injected electricity into the grid at any time during any capacity measurement period for the previous five pricing years."[6] As a result, an embedded generator inside a local network that never experiences a net flow onto the grid is not liable for HVDC charges, whereas the same generator would be liable if it were connected directly to the grid. This objection, however, overlooks the presence of the prudent discounts element of the current transmission pricing policy. The intention of prudent discounts is to avoid inefficient by-pass of the grid by compensating parties for the Transpower charges they actually face by forgoing a grid bypass that would be financially beneficial to them but economically inefficient for the economy as a whole.

3. Impact of controversy on efficiency

In short, most of the objections to the current HVDC charges regime are made on the grounds that some inefficiency results have no or debateable validity. The South Island generators, quite naturally, would prefer that someone other than they bear the charges. But their appeal is essentially one based on fairness and equity rather than efficiency.

This is not to say that the controversy about the current regime does not have efficiency implications. The uncertainty the ongoing dispute creates about the durability of the current transmission pricing methodology adversely impacts on the investment decisions of those who believe their interests could be disadvantaged in the event of any change in the pricing methodology. The standard suggestion of those opposed to the current regime is to roll the costs of the HVDC link into Transpower's interconnection charges. These are borne by large loads directly connected to the grid and distribution networks, which pass on the charges to the consumers connected to them. Thus the uncertainty around the future of HVDC charges most acutely impacts on the investment decision making of large loads.

There is good reason to try to resolve the issue and find a more acceptable, but efficient, basis for setting the charges for the HVDC link. This need is independent of whether or not the current review of the transmission pricing methodology by the Commission comes to the conclusion that the potential benefits from it providing accurate locational signals for generators and load are insufficient to warrant a major revision of the current pricing regime.

[5] See NERA 2009 Report, p. 63.

[6] Electricity Governance Rules, Part F, Section IV, Schedule F5, Rule 3 49.2.

It is against this background that Rio Tinto Alcan New Zealand Ltd (RTANZ) has asked NZIER to develop an alternative approach to charging for the HVDC link. The request is to develop a regime that better reflects how the costs of the link would be distributed had its construction and financing been left to the private sector and market negotiations. In other words, RTANZ has asked NZIER to come up with a "more market oriented" method of charging for the HVDC link as an alternative to the largely administrative allocation procedures that have been used up until now and been so contentious.

4. Market-based charging

4.1 Beneficiaries pay

A fundamental proposition of a market economy is that consumers will pay voluntarily for a good or service only up to the value of the benefits they expect to receive from it. They hope and may pay less, but they will not pay more. The corollary is that the costs of providing goods and services are allocated in a market framework on a "beneficiaries pay" basis.

4.2 Infrastructure investments

The provision of infrastructural services, such as electricity and gas transmission, roads or fibre-optic telecommunications cables, typically involves significant investment in specialised assets that, once the investment has been made, tend to be sunk assets. These have very limited value in their next best alternative use – a very low opportunity cost value. The presence of significant sunk costs makes investors vulnerable to opportunistic behaviour by buyers of their services; once the assets are in place, buyers can try to force down charges as the supplier has little option but to accept lower returns due to the low opportunity cost value of the sunk assets. If the number of potential buyers is relatively small, this magnifies the vulnerability of investors as it reduces the costs of buyers co-ordinating their approach either through explicit agreement or implicitly. If there is only one buyer, the vulnerability of the supplier can be very high.

On the other hand, there are generally very significant economies of scale in the provision of infrastructure assets and as a result there is often only one, or a very small number, of suppliers. This makes the users of the services provided by these assets vulnerable to opportunistic behaviour by suppliers threatening to withhold the services, especially if the services are essential ones.

4.3 Long-term contracts

A corollary is that when significant infrastructure assets have to be provided in a market without support from a regulator, or other statutory instrument, and there is only one, or a few, potential purchasers, it is common for the sellers and buyers to enter into long-term contracts. The terms of these contracts are intended to protect each party from opportunistic behaviour by its counterparty.

Common features of such long-term contracts are:

- take-or-pay conditions or capacity rights – the buyer is obliged to pay for a certain level of service or capacity, irrespective of whether or not the buyer uses it; generally the payments under these terms are designed to cover the capital and other fixed costs of the supplier
- variable charges based on utilisation – generally these are designed to cover the variable operating costs of the supplier
- service availability and quality obligations placed on the supplier
- a term long enough to allow the supplier to recover all its sunk costs and/or provisions for termination payments in the event of early termination or pre-specified roll-over conditions
- credit enhancement through the provision of bank support if the buyer's credit standing means it may not be able to make the regular payments and any termination payment and
- transferability of rights and obligations of the buyer but subject to the supplier being satisfied over the credit standing of the new buyer, or the credit support it offers.

Our proposed capacity rights regime for the HVDC link arises from consideration of how buyers and sellers deal with one another over the provision of large infrastructure assets when they cannot turn to a regulator to specify the nature of the relationship between them. The presumption is that solutions developed voluntarily in the market place tend to be efficient because over time the actions of parties seeking to promote their own interests result in inefficient arrangements and contractual forms being replaced by more efficient ones.

5. Capacity rights and the existing HVDC link

5.1 Feasibility for the HVDC link

For simplicity, we will discuss the application of a capacity rights approach to the existing HVDC link before considering its application to the extra capacity for the link the Commission has recently approved.

The basic idea of a capacity rights regime for transmission is that generators wishing to use a transmission connection subject to the regime need to hold a right entitling them to utilise the capacity they require. It is possible to operate such a regime on the HVDC link because the software used to determine dispatch can be amended to distinguish what output from which generators would be produced, irrespective of whether there was an HVDC link, from the output and generators that will produce only if there is an HVDC link. So it is possible to determine the extent to which output from a specific generator would use the HVDC link, if dispatched, and to dispatch only that output for which the generator holds (or simultaneously obtains) a valid capacity right.

A capacity rights regime would not be practical on the interconnected AC grid as it is much harder to simultaneously determine the dispatch order and determine which electrons from which generator will use which grid assets.

5.2 Proposed design

There are many issues that need to be considered when designing a capacity rights regime, but the important ones fall under the following headings:

- How to define the right?
- How to make the initial allocation of rights?
- How to organise and record subsequent transfers of rights?
- How to ensure that only parties with rights use the capacity?
- How to ensure that the outcome is as efficient as practicable?

5.2.1 Definition of capacity right

Each capacity right would allow its holder to holder to transmit across the HVDC link, in the half hour to which the right relates, the volume of electricity specified in the right (or a lesser amount), in the direction or directions in which the flow is operating during that half hour.

The capacity right would be subject to a force majeure provision to protect Transpower in the event the link is unavailable for any cause beyond its reasonable control.

Five working days before the beginning of a month, the holder of any capacity rights valid in the next month would be obliged to pay Transpower at the price at which Transpower originally sold the right, irrespective of whether it was to the current party or some alternate. In the event of a default, the ownership of the capacity right would pass back to Transpower, which would be obliged to offer it for sale. Transpower would be obliged to offer any such capacity rights for sale and could recover from the defaulting party any net loss it incurs in selling the right relative to what it would have received if there was no default.

5.2.2 Initial allocation of capacity rights

Two basic approaches which could be adopted are:

- auction (or tender) all the available capacity with every party able to meet the reasonable credit requirements set by the regulator permitted to bid or
- offer the available capacity to existing users of the HVDC link pro rata with their share of total use over the last, say, five years at a price that reflects Transpower's average required revenue per unit offered.

In both cases, it would seem sensible, as a way to reduce the complexity of initial allocation, to bundle the capacity rights for a whole year together for the initial allocation. Bundling would also ensure that the rights for half hours when there may be no constraint on the link are taken up. A successful bidder would receive the right to transmit the quantity of electricity to which the right relates across the HVDC link in every half hour of every day in the year to which the right relates.

In the first initial allocation, capacity rights covering the current and next two subsequent years would be offered. Each year there would be an initial allocation for the next year for which no allocation has so far been made.

An advantage of the auction approach is that it would allow the capacity rights to flow to the parties that value them most highly at the outset. So it should tend to reduce the transactions costs involved in achieving an efficient allocation of rights over time. A disadvantage is that it could lead to "monopolisation" of the rights by one or a small number of bidders. Moreover, bidders in an auction would be willing to bid up to the full value of the link to them, and in aggregate this would be considerably in excess of Transpower's full costs of providing the existing link of approximately $88 million per year.

The private benefit to generators from being able to "buy" electricity in one island and "sell" it in the other is approximately $240 million per year on average in the medium term, and significantly greater in the short term. If there was no inter-island link, competition among generators would drive prices in an average year in the South Island to close to the short-run marginal cost (SRMC) of generation there in the short to medium term. This is close to $0/MWh as South Island capacity is dominated by hydro and wind generators with very low operating costs.

On the other hand, in the absence of the link, competition in the North Island would drive prices very high, in the short run. Prices would have to go high enough to choke off sufficient North Island demand to match North Island supply. Even in the medium term, prices in the North Island would be approximately the long-run marginal cost (LRMC) of supply in that island, which is roughly $80/MWh in current prices. So the inter-island price differential in the absence of a link would in the medium term average roughly $80/MWh and in the short term it could be several times this figure. This differential will remain at about the LRMC of generation until the South Island needs to add to its existing capacity to meet South Island demand, which is likely to be several years away.

The net south-north flow on the HVDC link averaged approximately 3,000 GWh per year in the years leading up to the recent Commission decision to approve an upgrade of the HVDC link.[7] 3,000 GWh per year at $80/MWh is $240 million per year.

Bidders in an auction for initial allocations would be willing to bid up to the expected full value of the link to them and in aggregate this would be considerably in excess of

[7]. (see http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/HVDC/May08-proposal/2-section-a.pdf).

Transpower's full costs of providing the existing link of approximately $88 million per year. Under the auction approach, Transpower would receive excess returns on the HVDC link, which would be incompatible with the main thrust of its regulatory regime – to ensure it gets neither an excess nor deficient return over time.

A disadvantage of the pro rata grand parenting of historical use is that it does not easily facilitate changes in market shares or new entrants using the link and may as a result tend to discourage competition in both the generation and retailing markets. If not all of the parties eligible for allocations take up their entitlement, there needs to be another method of selling the capacity not taken up. This might be by reallocating any unwanted entitlements among the parties that have taken up their full allocations on a pro rata basis or by auctioning them.

On balance, we favour the pro rata grand parenting based on historical use over the previous five years at Transpower's unit cost with provision that if one or more parties do not accept their full entitlement then Transpower has the option of either putting the associated capacity rights up for auction immediately or holding the rights for later sale during the secondary trading of rights. Any auction would be open to all parties with a credit status or supporting guarantee which has been determined by the regulator to be acceptable.

If the revenue raised by Transpower through sale of capacity rights on a pro rata basis and a subsequent auction of the surplus is in excess of Transpower's full costs of providing the HVDC link, the surplus will be applied to reduce the sum Transpower collects by way of interconnection charges. On the other hand, if there is a shortfall this will be added to the amount Transpower collects as interconnection charges. If, however, Transpower decides not to auction surplus capacity rights immediately after the initial allocation but instead to hold them for later trading in the secondary market, it will bear all the risks and reap all the rewards that flow from this decision.

The intention of the arrangement for dealing with any surplus capacity rights after the pro rata allocation is to provide Transpower with the option to be assured of receiving its required revenue for the HVDC link but no more, if it so wishes, or to be able to back its judgement about the future value of capacity rights if it believes the market value is above costs.

5.2.3 Secondary trading

We propose that in the initial allocation phase, including in any auction held to deal with surplus rights not picked up by those with pro rata entitlements, the capacity rights be bundled together in annual parcels. A successful applicant or bidder would receive the right to transmit the quantity of electricity to which the right relates across the HVDC link in every half hour of every day in the year to which the right relates.

We propose secondary trading be conducted at the half-hour level. This would not, however, preclude parties from agreeing to trade the seller's full entitlement for a whole year or parcels of rights relating to all the specific half hours of a particular kind, such as the "peak" week-day half-hours or the weekend half-hours.

Transpower would be able to offer on the secondary market any capacity that was not allotted or auctioned in the initial allocation phase. It would also be able to trade any rights it has re-acquired as a result of a default or by purchase on market.

Any other party that meets the specified credit status or provides an acceptable guarantee, as laid down by the regulator, would also be able to participate in the secondary market. This would apply whether the party is engaged in electricity generation or not.

For trades prior to five working days before the beginning of the month to which the capacity rights traded relate, the buyer on the secondary market would take over the obligation to pay Transpower the pro rata share of the original amount set when Transpower offered the right for allotment. As a result, the purchaser would pay to, or receive from, the seller of the right a sum calculated after taking into account that the new owner has assumed this obligation.

For trades within five days of the beginning of the month, settlement would be between the buyers and sellers on the basis that the vendor has paid Transpower for the capacity rights that relate to the next month but not for subsequent months.

Trading in the secondary market could take place up to a point very close to the start of the half hour to which a capacity right relates. The only constraint would be the need for the system operator and generators to know the volume of capacity rights they hold when placing and considering energy offers in the spot electricity market.

A web-based market would be an appropriate vehicle for secondary trading.

5.2.4 Spot trading of capacity rights and dispatch

We propose a third mechanism for trading HVDC capacity rights. This would operate in conjunction with the offering of generation for dispatch and be integrated into the dispatch process.

Every holder of HVDC capacity rights, whether a generator or not, and including Transpower, if it still has rights following initial allocation and secondary market trading, would be able to offer rights for each half hour separately at a price or prices at which it is willing to sell. Every generator that offers generation would be able to bid for capacity rights.

The system operator would initially determine in the normal manner which generators it would dispatch, as if there were no HVDC capacity rights requirement to use the link. It would also determine which generators it would dispatch if there was no capacity available on the HVDC link. From comparison of these two dispatch solutions Transpower would work out which dispatch offers are required to meet intra-island flow requirements and which dispatch offers would provide electricity for inter-island flow across the HVDC link and the volume of inter-island flow there would be.

The system operator would next consider the offers for HVDC capacity rights and establish the offer price such that the volumes offered at this price, or less, would just cover the expected inter-island flow. This offer price is the market price for HVDC capacity for the half hour. The system operator would allocate the volume of HVDC capacity rights offered at or below this price to the generators whose dispatch offers in the spot electricity market are such that they would be dispatched to meet the inter-island flow, provided they have a bid for HVDC capacity rights at or above the market price for HVDC capacity.

If there are too few generators in the original dispatch stack with bids for HVDC capacity sufficiently high to satisfy demand for electricity, the system operator would progress further up the generator offer stack until either demand is fully satisfied or there are no more offers to consider. When demand is fully satisfied, the offer price of the marginal plant dispatched sets the price for generators as it does now. When demand is not fully satisfied, the usual procedures for resolving this situation in the physical market for electricity are employed.

The successful vendors of HVDC capacity rights receive the market price for HVDC capacity rights and the parties allocated these rights pay this price on the volume allocated to them. Settlement for HVDC capacity rights could be handled in conjunction with settlement of the electricity market, which would occur in the same manner as market settlements do at present.

A generator that holds HVDC capacity rights to cover its offered output would offer the rights at a low price, say zero, and bid for rights at a high price. The outcome of the market processes described above would generally be that the generator would both buy and sell the same volume of capacity rights at the market clearing price. It would not face a net settlement and its cost of capacity would be what it set when it acquired the rights in the initial allocation or the secondary market. It would have fully hedged its costs of using the HVDC link.

It is also possible that a generator’s output could be dispatched without the need for a capacity right but the capacity right it offered in the spot market is allocated to some other party. The generator would in this case receive a net payment for its capacity right. It is also conceivable that the generator could be dispatched and need a capacity right but not manage to sell its own capacity right because there are so many offered at the same zero price. However, for this to occur the market price for HVDC capacity rights would have to be zero and so the generator would not make any payment for any right it acquired either.

6. Capacity rights for an expanded HVDC link

The Commission has already approved the replacement of one pole of the HVDC link and expansion of its capacity. The difficulty with applying the above proposed regime to an expanded link is that, to take advantage of economies of scale, the expanded link will have more capacity than is likely to be necessary to meet demand for several years yet. This will be the case for virtually every half hour. In this situation, if all the expanded capacity was made available, there would be little incentive for anyone to buy capacity rights in the initial pro rata allocation process or through secondary trading. The better option would be to acquire needed rights on the spot market for them at the time of dispatch. Given that, if all available capacity is offered, supply would exceed demand, this could be done at zero price.

A simple means to overcome this potential problem is to restrict the supply of capacity rights offered in the initial pro rata allocation process. Implicit in Transpower's application to approve the upgrade and expansion of the HVDC link are forecasts about the level of capacity of the link required over each of the next 30 years. There is not a single forecast but a range of forecasts reflecting the Commission's different market development scenarios (MDS), as set out in the Statement of Opportunities (SOO), and different demand growth forecasts. However, from applying weights to the various component forecasts a "mean" forecast of required link capacity in future years could be derived.

The capacity offered for allotment on a pro rata basis each year should be this forecast of required link capacity, unless Transpower is able to convince the Commerce Commission that offering a lesser or greater capacity in any particular year or years would promote the long-term benefit of consumers of electricity. The price at which capacity should be offered for pro rata allocation should be such that if all the capacity is taken up Transpower would recover its required revenue for the upgraded and expanded HVDC link in full.

An issue likely to arise if not all available physical capacity is offered in the pro rata allotment is public and political pressure on Transpower and the regulator to increase the level of allocation when doing so would reduce wholesale electricity prices. This issue could be avoided by requiring Transpower to offer in the secondary and spot markets for capacity rights all the capacity not offered in the pro rata allocation at a price, say 100%, above the price at which the capacity was offered in the pro rata allocation process. Transpower could be paid a management fee for providing this service and any revenue net of this fee raised by selling the extra capacity could be applied to reduce the level of revenue to be raised by interconnection charges the next year. This would be less distortionary than rebating the sums raised back to generators on the basis of their HVDC charges, for example.

In other respects, the proposal as put forward for charging for the current HVDC capacity could be applied to the charging for the upgraded and expanded HVDC link when it comes into operation.

7. Evaluation of the proposal

7.1 Advantages over status quo

In several ways the proposal is not vastly different to the current HVDC charging regime. In fact, the current regime can be thought of as being very close to a special case of the proposed regime in which South Island generators are required to accept their pro rata allocation and are not entitled to trade the capacity rights they receive. However, the proposal does have several advantages when compared with the status quo:

- those that benefit from the HVDC link and use it will bear the costs of its provision – this is not necessarily the case under the current regime
- changes in flow direction and the parties using the link are much more readily and efficiently catered for
- it does not impose HVDC related costs on peaking plants and other generators that do not contribute to the inter-island flows of electricity and
- it does not distinguish between deeply embedded and directly connected generators – the requirement to pay for the HVDC link falls on those who use it irrespective of how they are connected.

7.2 Other advantages

The proposal has several other favourable features:

- its implementation would require only minor modification of the system operator's dispatch software to handle spot trading of capacity rights and the requirements for plant dispatched to use the HVDC link to hold rights
- its implementation would not require the other components of transmission pricing methodology to be altered at the same time
- it is able to cater for the upgrade and expansion of the link recently approved by the Commission and
- it would remove the need to create and trade FTR rights relating to the HVDC link and its upgrade and expansion, as owners of capacity rights would have a fully hedged position regarding the costs of transmission on this element of the grid.

Most importantly, the proposal should be more acceptable than the current HVDC charges regime. It is hard to object to "beneficiary pays" as a principle. This is why the opponents of the current regime have highlighted that, in their opinion, there are other beneficiaries of the link than the South Island generators currently paying for it. If their claims are correct, the proposal will end up with all the beneficiaries among the users paying.

7.3 Disadvantages

A disadvantage of the proposal compared with the current regime is that it would require establishment and operation of trading and settlement mechanisms for capacity rights and operation of a registry of ownership of capacity rights. It would also add slightly to the complexity of the scheduling and dispatch process used in the wholesale market.

7.4 Balance of costs and benefits

Very significant amounts of money have been spent on debating and reviewing the current HVDC charge regime in the last 15 years. The uncertainty this has created has also undoubtedly had an impact on the efficiency of investment decision making by energy intensive load and generators. In view of this, the incremental operation costs for our proposal over the status quo would appear likely to be small compared with the incremental benefits in terms of reduced dispute costs and improved investment decision making.