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Memorandum

TO: **TLFMG**

CC: **Graham Shuttleworth**

FROM: **Isabelle McKenzie and Maureen McCaffrey**

SUBJECT: **Phasing of implementation**

DATE: **14 August 2002**

1. PHASING OF NEW PROPOSALS

This paper has been prepared on behalf of and at the request of the TLFMG by NERA and Conoco to address some of the issues raised at TLFMG meetings about the phasing proposals. This memorandum first sets out the reasons for phasing of the proposed modifications to the charging regime for transmission losses, P75 and P82. This memo does not supersede the need for cost benefit analysis for phasing during the assessment of the two modifications, but aims to set out the *economic* reasoning behind phasing of large changes to market rules. It then examines some precedents for mitigation of market changes and then directly addresses the sources of data required for the phasing proposals presented to the TLFMG.

1.1. NGC's Licence Conditions

Any change to the BSC must be compared to NGC's licence conditions. In this context, two licence conditions are important: first, objective (b), the efficient, economic and co-ordinated operation of the transmission system and second, objective (c) effective competition in generation and supply of electricity. Efficiency in transmission systems includes efficient dispatch and efficient location of generation and demand. However, the benefits of implementing any change in the trading arrangements to promote efficiency must outweigh the costs.

BSC objective (c) states that the Transmission Company must promote "effective competition in the generation and supply of electricity, and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity". Promotion of "effective competition" is a description of market arrangements designed to promote economic efficiency, ie to promote *efficient* new entry or to prevent *inefficient* exit from the market.[1]

When analysing economic efficiency, the particular structure and characteristics of the industry must be considered. The electricity industry is characterised by capital intensive, long-term irreversible investment and is unable to respond to signals by moving existing plant, only in new investments and closure decisions.[2] Electricity industry investment is, therefore, more vulnerable to stranded assets and under-recovery of investment than some other industries. As a result, the concept of economic efficiency must be applied carefully. When analysing a change to market rules, particularly when there are pricing implications, the following must be considered:

- Investors perception of risks (and the change thereof);
- Incentives to react to and hedge risks; and
- Economic efficiency of investment and risk-management.

To illustrate why it is important to understand if market risk changes with a new proposal, Enron estimated the impact of a move to marginal loss factors in their submission to Ofgem in 2001. Enron estimated that the long-term investment uncertainty caused by a change to the charging regime, in their submission as follows:

> "We estimate that moving to variable loss factors would increase the discount rate for new generation by approximately 1%. This corresponds to an increase in the cost of new entry by £0.50 / MWh, which in the long-run would be equivalent to adding roughly 2.5 percent to the wholesale price of electricity."[3]

We have not attempted to validate this figure at this stage. However, if the risks associated with recovering sunk investments increase by virtue of a change in market rules, then eventually it will impact on the market price for electricity. In a 300 TWh annual market, an increase of £0.50 per MWh equates to an annual additional cost of £150 million, far in excess of any savings in reduced losses on the system. Any change to trading arrangements should take into account the fundamental nature of the electricity market and aim to mitigate against any increase in risk to participants.

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1 For a further discussion on the application of NGC's licence conditions, see NERA paper "Assessment Criteria for Modifications P75 and P82" 27 May 2002.

2 Conoco estimates that fixed investment costs, as defined under tax law, equates to around 80% of the total capital invested. Some capital costs in the electricity industry can be recovered. There may be some resale value to old plant and there may be some residual value to the land and any infrastructure connections.

In context, investor confidence is extremely low in a post-Enron market, and any new arrangements should be particularly careful not to further undermine investment in the market. The phasing proposals from NERA are designed to mitigate against the risks to participants and customers, thereby helping investor confidence and reducing regulatory and investment risk.

1.2. Principles for Changing the Loss Allocation Rules

NERA has developed three simple principles that we believe to be *incontrovertible*. That is, we cannot foresee any conditions in which regulatory decisions should not abide by them.

(1) Any reallocation of transmission losses should increase *efficiency*

Ofgem has already referred to the desire for economic efficiency in its consultations on the allocation of transmission losses.[4] In many cases, economic efficiency can be improved by setting price signals equal to marginal costs, which is asserted by Powergen in its justification for the modification proposal P75.[5] However, there are several circumstances where an abrupt move to marginal cost pricing will have little or no effect, or will even *decrease* efficiency.

- **Sunk costs.** In industries dominated by long-term, irreversible investments, changing short-term price signals will have very little effect in the short-run.[6] The potential benefits from signalling marginal costs are therefore small. On the other hand, changing the system of cost allocation will affect the values of these long-term, irreversible investments. When such changes harm long-term cost recovery in an unpredictable manner (ie, by means against which investors cannot secure an efficient hedge), they will actually damage incentives for efficient long-term investment. Since investment is such a significant proportion of total costs, this damage can easily outweigh the potential benefits.

- **Constraints on choices.** Where despatch is constrained by transmission congestion, the re-allocation of relatively minor costs such as losses will have little impact on the pattern of output. In such conditions, a change in pricing policy creates transfers of welfare between different players in the market, but produces little or no *net* gain. Only the achieved net gain counts as an increase in economic efficiency.

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3 Enron submission to the consultation on transmission access and losses under NETA (May 2001), p15

4 OFGEM *NGC System Operator Incentives, Transmission Access and Losses under NETA: A Consultation Document*, December 1999, pages 32 and 89.

5 In some cases, where there are fixed costs or economies of scale, setting all prices equal to marginal cost is infeasible, because it will prevent total cost recovery and discourage efficient investment.

6 Sunk costs include the ongoing financing costs, which are unavoidable, but also a cash cost.

- **Distortions in other markets.** There are often distortions (ie, prices do not equal marginal cost) in other markets, as in the regulated prices of (electricity and gas) transmission access and the negotiated prices for certain fuels. Given these distortions in one market, the most efficient outcome may require offsetting distortions in another market. Moving prices closer to marginal cost in this market can then actually exacerbate distortions in other markets and decrease economic efficiency overall.

  If Ofgem believed there to be cross-subsidies in charging then a rule change that lead to more cost-reflective charging could be argued to better facilitate competition (subject to caveats about undermining investment etc). However, in considering whether there are cross-subsidies and considering their potential effects on competition, Ofgem would need to consider carefully the interaction with other NGC charges. Given the well-understood weaknesses associated with ICRP, which underpins NGC's TNUoS charges, and the national averaging of BSUoS charges, it is possible that a move to zonal losses could lead to increased cross-subsidies between Northern and Southern generators when all charges are taken into account.

The implication of this principle is that regulatory decisions must be guided by an analysis of the *actual* likely effects on *efficiency*, and cannot be taken simply as a matter of applying rules-of-thumb (such as “price equals marginal cost”).

(2) To increase efficiency, it is not necessary to withdraw existing rights

Users’ rights of access to the transmission grid are set out at present in the NGC Connection and Use of System Agreement, in the related supplemental agreements, and in the Balancing and Settlement Code (which defines de facto trading rights and allocates transmission losses). These agreements may or may not provide long-term contractual certainty; however, it is incontrovertible that these agreements award some rights at present. It is also incontrovertible that these existing rights *could* be maintained in the future, by being converted into some alternative right. Arrangements for trading and transmitting energy will change in future, but it will always be possible to design contract and tariff arrangements that cause users to pay only what they pay now, for exercising their existing rights.

As a consequence, it is not necessary to *withdraw* existing rights, whatever the future of electricity trading. Any action to withdraw, or abolish, existing rights would be a conscious decision in itself, not a necessary consequence of other decisions.

(3) Withdrawing existing rights without good reason damages efficiency

Long-term contracts provide traders with a means of long-term risk management, and thereby allow more efficient investment to take place. The use of long-term contracts is also consistent with efficiency in the short-term, as long as contracts are *tradeable*; if contracts can be traded, the opportunity costs of a contract will equal marginal costs or market prices.

In practice, investors have been unable to secure efficient long-term contracts to provide a specific hedge against variation in the allocation of transmission losses. Users of the system have some say in the allocation of losses at present, through participation in the Balancing and Settlement Code and previously through the Pooling and Settlement Agreement (P&SA).[7]

Given that withdrawing existing rights is a separate and conscious regulatory decision from the BSC Panel and ratified by Ofgem, any decision about losses needs to take into account the consequences for economic efficiency. In particular, withdrawing existing rights arbitrarily – that is without explaining what is to be gained by the decision – will create (unnecessary) regulatory risk. Investors will respond inefficiently if it appears that the allocation of losses or charges might vary unpredictably in the future. They will ignore the current price signals in favour of spreading investments around the system, or of minimising irreversible investments. Neither approach is efficient.

Hence, regulators need to avoid decisions that create windfall gains or losses. If regulators have good reason to impose such gains and losses, they need to set out these reasons clearly, in order to avoid creating the impression that such effects are in fact accidental and arbitrary results of applying "rules of thumb" such as prices should equal marginal costs.

1.3. Conclusion

We have applied three principles that apply to all regulatory decisions, in the context of losses:

1. any reallocation of transmission losses should increase efficiency;
2. to increase efficiency, it is not necessary to withdraw existing rights; and
3. withdrawing existing rights without good reason damages efficiency.

Given these principles, it is in the interests of long-term economic efficiency to preserve some aspects of the existing arrangements for allocating transmission losses. The argument springs from the **third** principle. Investors require long-term certainty to make efficient decisions. Such certainty is damaged by regulatory decisions that change existing arrangements without good reason, in ways that impose arbitrary windfall gains and losses. Hence, withdrawing existing rights without good reason (ie, arbitrarily) harms efficiency.

[7] Large portfolio investors can manage risks by spreading their investments all around the system. However, such a pattern of investment is not efficient in current conditions, when the system experiences a North-South flow.

The two phasing proposals developed by NERA demonstrate the truth of the **second** principle, that it is unnecessary to withdraw existing rights with regard to transmission losses. To show how to achieve the desired stability, we *presume* that the **first** principle leads to a demand for transmission losses to be allocated by new rules and, for the purposes of demonstration, we refer to allocation based on marginal costs as an example. We have not conducted any analysis to suggest that a marginal cost approach would be best. However, using this example shows that it is not necessary to withdraw existing rights *even if* Ofgem or the BSC Panel wishes to provide short-term signals based on marginal costs. In practice, the exact process used to allocate transmission losses initially does not affect our application of the second principle, ie it could be used with P75, P82 or any alternative scheme.

In practice, Ofgem is also constrained by the need to take into account customer interests as well as promoting competition. The NERA approach allows the correct incentives at the margin (promoting efficiency), from the first day of implementation, but allows a phased introduction of the overall proposal, reducing the risks to participants (in a post Enron era) and any sudden changes to customer bills. It is therefore closer aligned to Ofgem's obligations than the marginal losses scheme on its own.

2. PRECEDENTS FOR PHASING

The basis for the proposed scheme is to phase in the introduction of a large change to market rules to prevent stranding of assets and to gradually introduce the new signals. The following section demonstrates some international precedents for phasing.

- **1992 NGC Charging Review:** Offer agreed to the phasing of changes for the following reasons "NGC is bound to make charges more cost-reflective and to provide signals to end users, although this objective must be balanced with practicality in that users may find it difficult to adjust to a change in their cost of transmission use of system overnight. It is therefore proposed that implementation by phased in over a period of 3 years."[8]
- **Gas entry/exit commodity charges:** Ofgem agreed to a delay in the introduction of entry and exit commodity charges in gas by a year to allow companies to adapt contracts and manage risks associated with the change in charging structures.
- **Delay in new exit capacity charges:** Ofgem agreed a delay of two years in the introduction of the new exit capacity arrangements to allow customers to develop risk mitigation and prepare for changes, despite Ofgem stating that it believed that the current arrangements were discriminatory.

[8] "Transmission Use of System Charges Review, Proposed Investment Cost Related Pricing" June 30, 1992

- **LDZ charging 2002:** In July 2002, Ofgem published, *Separation of Transco's Distribution Price Controls,* its proposals regarding the future charging in the Local Distribution Zones (LDZ) for the gas market in Britain. Ofgem proposes to move from uniform LDZ charges to the phased introduction of changes to the charging regime, allowing regional differentials in gas charges to develop over time. Ofgem states "In order therefore to minimise the disruption to consumers it may be appropriate to phase in any regional variations in charges."[9] In fact, these proposals are not likely to be implemented in advance of the next price control in 2007 and the price differentials will develop over time.

- **DEFRA Recommendations 2002:** In the DEFRA document, *Extending Opportunities for Competition in the Water Industry in England and Wales: Consultation Paper*, July 2002, it states that "If Undertakers [incumbent companies] were not compensated for these stranded asset costs, [caused by changes in market rules] this could affect undertaker's future investment decisions."[10] DEFRA recognises that changes to the market rules can act as a disincentive to future investment decisions if incumbent companies are not able to recover their sunk investments.

- **Dutch Electricity Protocol 1996:** During the transition to competition in the Netherlands, distribution companies agreed to cover the costs of SEP, the central body responsible for a large generation portfolio and for the national grid. Most of SEP's costs were recovered through conventional tariffs for SEP's services. However, any short-fall was allocated among the distribution companies in proportion to their demand in 1994, the year before negotations opened. This protocol is due to come to an end in 2001, but SEP is still discussing with the government how to recover its outstanding commitments.

- **Spanish Stranded Costs:** The liberalisation of the Spanish electricity market allowed for the continued recovery of certain sunk costs. Eligibility for recovery of these "Costs of Transition to Competition" (CTC) was limited to generators that were available before a certain date; the estimate of their future costs was based on historical information about their annual running time. The duration of this entitlement has always been open to question; as a result, generators' decisions on operations and pricing have sometimes been adversely affected by the desire to maximise early recovery of the CTC.

- **British Gas Legacy Contracts:** Before liberalisation of the UK gas market, British Gas sold gas to a variety of customers (including many generators) through long-term tariff agreements (eg, "LTI2" and LTI3"). Conversion of these long-term agreements proved difficult, because they had not foreseen the need for unbundling terms and conditions between gas and transmission. In contrast, the proposed scheme for

[9] Paragraph 1.15

[10] Paragraph 187

transmission losses clearly distinguishes between (1) the current allocation of transmission losses and (2) the contract adjustment designed to provide stability over a transition. Furthermore, legacy contracts were non-transferable, such that users decided how to use them on the basis of the contract price, rather than the opportunity cost of gas (ie, the current market price). The proposed scheme specifically makes the contract adjustment entitlements transferable, in order to ensure efficient utilisation.

- **The Skagerrak Link Connecting Denmark and Norway:** Access to the Skagerrak subsea power link connecting Denmark and Norway was opened to all players in 2001. Access to the link had been tied up due to the form of existing contracts between Statkraft, Elsam and Preussen Elektra. However, the players have agreed to convert the existing physical contracts into financial contracts following criticism from Danish power traders that the existing contracts hindered competition across the Nordic market. The new financial contracts opens the 1,000 MW link between the two countries to third party access whilst allowing the incumbents to maintain the financial benefits of their existing rights.

Ofgem has provided a number of examples where large changes to charging arrangements have been phased to allow companies and customers to adjust to the changes and to implement risk management techniques.

The proposal for phasing of marginal transmission loss signals also provides an opportunity to reduce the risks and costs to participants by phasing in changes to charging mechanisms, whilst retaining the marginal signals and the signals for new plant. Not only does it give generators and industry participants the time to develop their own arrangements, it also smoothes the price changes for consumers, particularly in the south and south west of England.

3. PRACTICAL IMPLEMENTATION OF PHASING

3.1. Phasing Proposal 1 – Phasing based on a baseline generation volume

3.1.1. Brief summary of the phasing proposal

Under a phased scheme, each (production or consumption) BMU would be allocated losses on a mixed basis:

1. in relation to a fixed quantity of output or consumption (F), the BMU would receive an allocation equal to 45% or 55% of average losses, as at present;

2. in relation to the difference between the fixed quantity (F) and actual production or consumption (A), the BMU would receive an allocation equal to the future loss factor (ie, TLF * (A-F));

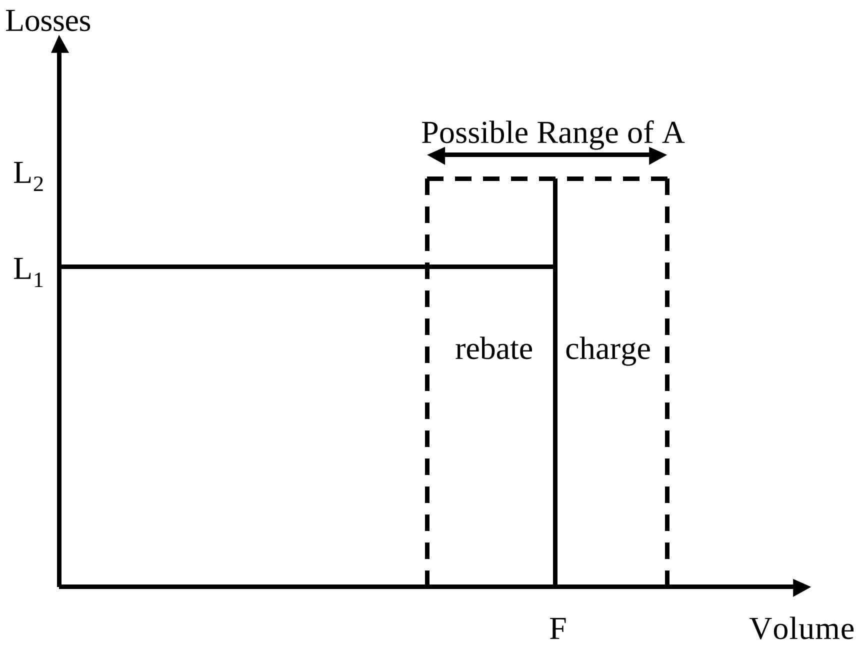
3. to ensure efficient cost recovery, any remaining balance of losses (positive or negative) would be spread (i) over all BMUs in proportion to the F term and (ii) by adjusting future loss factors via the TLMO+ and TLMO- term in section T of the BSC.

To provide the transitional arrangement, the BSC would define a factor ($1>=\alpha>=0$) which would move gradually from 1 to 0 over a period of years. This factor would be used in step 1 to scale down the fixed quantities (F), such that the protection against risk afforded by the scheme in each year would be equal to αF. It would also be used in step 3, to allocate residual losses between the two schemes in the proportion to α and 1-α.

Over time, the proportion of energy subject to transmission loss factors will increase until all consumption and generation is subject to this factor. Phasing of transmission loss factors will protect consumers from abrupt changes in electricity prices, while protecting sunk investments in generation.

The proposed scheme provides the necessary combination of short-term signals and long-term stability needs to provide incentives based on any desired pricing signal, combined with the necessary **protection** against variation in charges (whether the changes are due to technical or regulatory factors).

Phasing in implementation of TLF by this method will retain any desired pricing signals under that TLF scheme for *changes* in volume of output, relative to some baseline. The phasing formula would establish a baseline volume of energy for any particular generating station or customer (BMU), most likely based on past generation or consumption. For this fixed volume, F, the user would be liable for losses at the current rate. Any difference between actual output, A, and F would incur (if positive) or earn (if negative) an allocation of losses at the marginal rate set out in TLF. (See diagram below.) If the BMU generated/consumed (as applicable) at the same level as F, it would pay the same losses as under the current system. However, short-term incentives to vary generation/consumption around F would depend on the marginal rate of losses. The baseline figure, F, would be tradeable among certain parties (nationally or within a zone), to ensure its value is determined by future loss factors, so that it would provide good long-term incentives. The baseline figures for each BMU would be allocated initially to the party connected to NGC's transmission grid, ie a generator, a customer or a distribution network.



L1 = losses allocated to volume F using current system (45% or 55% of average losses)

L2 = losses allocated to volume (A-F) using future loss factors

To effect a transition, the baseline figure, F, would decline over time towards 0, thereby increasing the user's exposure to the new loss factors.

3.1.2. Defining F

The "F" term replicates the typical generation or consumption of BM units prior to the introduction of marginal charging mechanism for losses. At the introduction of phasing, the typical level of generation must be calculated.

When deciding how to define F, the guiding principle should be to provide users with a risk management tool against changes in marginal loss factors, such that their net costs are unchanged if their usage continues to follow the pattern of their existing rights to use the transmission system. The implied rule is that users would be awarded a long-term hedging contract against variation in losses, sufficient to cover future production and consumption, and consistent with their existing rights. In what follows, we define the key choices and recommend the approach that most closely meets this principle.

- **Starting Point for Producer's Contract Amount**

The starting point for defining users' existing rights to use the transmission system must be an objectively derived measure of past usage (meaning actual production or consumption in each half-hour). For producers, the following choices are possible:

1. Single F for all periods j

   = Usage as of a defined point (or points) in time, eg, the last period of peak demand on the system, or the average of the triads for 2001-2002.

2. Individual F for each period j

   = Usage as of the corresponding half-hour in the last year unaffected by Ofgem's proposals (probably 2001-2002).

3. Individual average F for each period j

   = Average usage as of the corresponding half-hour in the 5 years up to 2001-2002, or over the period since connection (whichever is the shorter).

Option 1 focuses on one recent period, but overstates the level of usage outside peak periods and may therefore lead to over-compensation. It could also be vulnerable to one-off availability problems at in the short periods of the triads. However, over-compensation could also be a problem for any rule for defining F by reference to connected capacity.

Option 2 provides a more realistic estimate of the extent to which existing users would be expected to use the transmission system, since it allows for variation in production and consumption. This option also captures the effect of transmission constraints – and hence prevents generators from being compensated when they would in any case have been constrained off. However, the figures for one year would be affected by random events, such as forced outages (and temporary constraints) and may not therefore provide a good indication of expected output.

On the basis of these arguments, Option 3, which uses a longer historical series of production and consumption to estimate future usage, appears to offer the best solution. We believe a period of 5 years will be sufficient to eliminate random effects, but alternative longer and shorter periods could be examined to see at what point the desired stability emerges. Using historical data from more than 5 years back runs the risk of producing unrepresentative figures that have been outdated by changes in industry structure.

- **Starting Point for Consumer's Contract Amount**

The modifications would cover both the producers and consumers on the system. In practice, we foresee many unnecessary difficulties in tying these arrangements to *individual* customers. Customers turn over relatively quickly and, in any case, may have no contractual link with the power markets, the balancing and settlement mechanisms, or the contracts for use of the system.[11]

At present, NGC's transmission demand charges are levied on *suppliers*, but even this option may prove untenable. The scheme will work best if the contract adjustment payments are long-term, tradeable commitments. Suppliers will be unwilling to accept such commitments if they anticipate rapid changes in their customer base; imposing such commitments on suppliers may run unduly high risks of bankruptcy and other forms of default.

The BSC Panel might prefer not to apply the phasing scheme to the demand side, on the grounds that it does not entail such large and long-term investments as in generation, but some large consumers will undoubtedly disagree. Furthermore, complaints about "rate-shock" are not confined to large consumers; we are aware that previous revisions to transmission prices have aroused complaints from (South-Western) MPs among others, on behalf of their constituents. Whatever the reason, the BSC Panel may find it difficult to deny consumers access to similar stabilisation measures.

The remaining option is to allocate any contract adjustment to the parties actually connected to the transmission network, ie, to large consumers connected to HV lines, and to the *distribution businesses*. The stabilisation of charges for transmission losses would then be passed through to customers connected at low voltage via an adjustment to annual DUOS charges. Actual transmission losses could continue to be charged to suppliers as at present.

Attributing the adjustment of transmission losses to distribution businesses has many advantages in defining the contract amount, F, since it is the distribution business that has long term relationships with customers, not the supply business. This means the past pattern of energy flows into a distribution network is a good guide to future flows, regardless of customers switching supplier, whereas the past pattern of energy attributable to a supplier may not be. Incentives to minimise losses will not be affected by channelling the fixed adjustment through the distribution business. Indeed, assigning the actual losses to distribution businesses (rather than directly to suppliers) might allow incentive regulation of the distribution businesses that encourages them to put pressure on NGC to reduce transmission losses where appropriate.

Therefore, applying one of the options for the contract adjustment to each distribution business's actual intake of electricity from the transmission grid seems to be the most practical solution.

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[11] Use of system is currently covered by the Master Connection and Use of System Agreement, but will become subject to a Connection and Use of System Code.

- **New generation and consumption**

For new generation and consumption, an F value will be required, but no historic data will be available. New generation and consumption would be included in the phasing scheme to ensure that new investments also have access to the hedging and risk management benefits of phasing. New generation and consumption F factors will be based on the size of the network connection for the site.

- **Degree of Aggregation Over Time Periods**

Option 3 can be implemented for each half-hour of each year, but it would be possible to build in some additional smoothing by aggregating half-hourly periods into larger blocks to match any aggregation designed into the detail of the losses modification eg ex-ante, yearly figures or ex-post half hour figures. Aggregation would smooth out some of the random fluctuations in individual half-hours, and would reduce the number of parameters applying to each user.

We cannot see any great advantage in such an approach, given the adoption of Option 3. The use of data for 5 years would already provide a degree of smoothing. Aggregating half-hours requires the selection of arbitrary divisions of time into peak, off-peak, weekday, weekend, or other periods. Such divisions are only likely to promote disputes. Furthermore, today's computer databases are more than capable of retaining the thousands of data points required for half-hourly calculations. Hence, with the possible exception of pumped storage units, which show much greater variability in output/consumption than other users, there is no real advantage in aggregating factors over longer time periods.

- **Conclusions**

The TLFMG would decide which of the options set out above to put forward to the panel. If ratified by the Panel, it would provide the principles on which the F term can be calculated for all BM units. All three options use information that is available from existing data held in settlement and it does not rely on any subjective data such as progress of Section 36 consents.

3.1.3. Measuring A

The "A" term relates to the actual production or consumption by each BM unit. The equivalent term recorded for settlement is QM_{ij}, where consumption is negative and production of electricity is positive. The settlement system already records this information on a half hour basis to calculate imbalance charges. In addition, for non-half hourly sites, there are procedures in place within the BSC to allocate consumption to each supplier (equally, it could be allocated to the distribution companies).

Under the phasing proposal, actual consumption and generation would be compared with the "F" factor for each individual site. Like the current losses system, charges would be calculated for each half hour period using the relevant F and A factors.

3.1.4. Measuring

The factor provides the phasing element to the proposal. The protection offered by the historical volume F, would decline linearly over a fixed period. The factor depends on the length of the phasing period. To define the phasing period, the life span of investor's commitments should be taken into account and the following options should be considered.

1. a fixed period for all generators and consumers, based on the average remaining life of plant currently connected to the system;
2. evidence provided by investors in relation to specific project documents, eg, prospectuses, bankers' convenants, planning submissions, etc;
3. standard lives based on engineering opinion, custom and practice;
4. asset lives accepted for tax purposes for key pieces of equipment (eg, turbines); and
5. connection agreements (where a "remaining life" is defined for charging purposes).

Option 1 is the most likely outcome as it is the easiest to administrate and is the least contentious. Option 1 also ensures that all plant and consumers receive the same risk management benefit of phasing rather than extra benefit going to incumbent players. Option 5 has some intrinsic relevance, since it defines how long users have a contractual right to use the system without new investment, but would be impractical if connections involved a mixture of new and old assets. Option 4 is reasonably objective, since the asset lives are already defined and have passed the scrutiny of other government agencies (ie, the Inland Revenue). The figures for individual projects may have been adjusted for irrelevant reasons (eg, to provide accelerated depreciation and other investment allowances), so this option would be useful if it is possible to identify standard practice.

Option 3 is attractive, if the figures can be based on actual evidence, since it avoids discussing individual circumstances, but will not be practical if it remains entirely subjective. Option 2 may only produce a plethora of conflicting and inconsistent answers.

Overall, therefore, we would expect the outcome to be Option 1 or Option 3, with the proviso that if Option 3 is chosen then the decisions on standard lives should be based on real life evidence of the type provided by Options 2 and 4.

3.2. Phasing Proposal 2 – Phasing based on proportional charges

The second phasing proposal uses similar concepts to the first phasing proposal, such as . We have not re-iterated these areas of duplication below.

3.2.1. Brief summary of the phasing proposal

Under the second phasing proposal, transmission loss factors would be a combination of two figures, appropriately weighted. The first element would be calculated using a new loss factor methodology, to give a 'marginal loss factor' (MLF) applicable to each BMU. The second element would be calculated using the current method of average loss factors (ALF), based on the 45:55 split (ie taking into account the differences in transformer losses). The interim loss factor ILF would be a weighted average of these two figures:

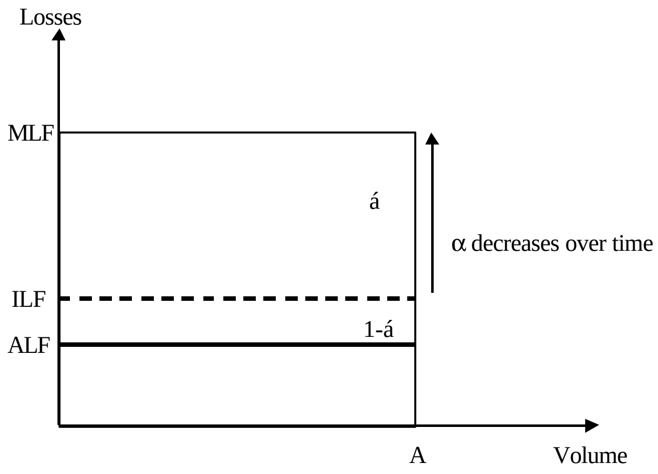
$ILF = \alpha.ALF + (1-\alpha).MLF$

Here, α would be set to one at first and would gradually fall towards a value of zero. Since charges based on ILFs would not necessarily recover all and only the cost of transmission losses, the final transmission loss factors (TLF) would be adjusted by a uniform mark-up (or mark-down), β, such that total allocated losses equals total actual losses by half-hour:

$TLF = \beta.ILF$

The use of α phases in the marginal loss factors, thereby reducing both windfall gains and losses (arising from the transition) and unhedgeable risks (arising out of the unpredictability of marginal loss factors). The phasing would mean that, initially, participants would not experience a large change in the cost of losses but, over a defined period, they would become more exposed to the zonal marginal loss signals.

The figure below shows losses allocated to the output (A) of a generator in a northerly zone. ALF is the average loss factor based on the current allocation of losses (45% of average, on a uniform basis, say 1% in all); MLF is the loss factor based on marginal losses (say 5% in all). In a transitional phase, the generator would be allocated a weighted average of these two figures, with the weight on the current system being α and the weight on the new system being $(1-\alpha)$. Over time, α would shift from 1 to 0, in order to shift from the current system to the new one.



3.2.2. Defining A

A is the actual generation or consumption for a particular BM unit. This information is derived from actual settlement data and is explained in more detail in section 3.1.3 above.

3.2.3. Defining

is the term used to provide phasing. The definition of is the same as section 3.1.4 above.

3.2.4. Defining â

â is the factor that ensures that actual losses equals losses charged to participants. In each period, â is calculated by subtracting the actual losses on the system with the attributed losses under the TLF calculation. The data for this calculation is already available within settlement.