Ref. 2/310/12

29 September, 1999

Mr Michael Rawstron
General Manager
Regulatory Affairs – Electricity
ACCC
PO Box 1199
DICKSON ACT 2602

Dear Michael,

POWERLINK'S RESPONSE TO THE PROPOSED CODE CHANGES RELATING TO THE NECA TRANSMISSION AND DISTRIBUTION PRICING REVIEW

Please find attached our response relating to the proposed changes associated with the Pricing Review.

Please do not hesitate to contact me should you wish to discuss this matter further.

Yours sincerely,

Owen West
A/MANAGER BUSINESS DEVELOPMENT

Enquiries: Mr T Miller Telephone: (07) 3860 2710

Powerlink Queensland

Response to ACCC – Network Pricing Code Changes Emanating From the Transmission & Distribution Pricing Review

Powerlink Queensland

Date: 29 September 1999

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SUMMARY

We have provided our response in 2 sections:

Section 1 responds to the ACCC's Issues Paper of September 1999.

Section 2 responds specifically to NECA's proposed amendments to Chapters 5 and 6 of the NEC.

This submission identifies the following major issues:

1. The process for advancing large new augmentations

The "beneficiary pays" part of the process – as currently defined – provides ample opportunities for the "losers" and "cost-avoiders" to delay the whole augmentation (not just the allocation of transmission charges). The process – as defined – is based on assumptions of generator behaviour, which are easy to challenge; the process can go on indefinitely (no time limit) as "losers" challenge the proponent to model more and more different combinations of assumptions. In addition, there is no "fallback" or default allocation which would bring the process to a firm conclusion in the absence of"convergence" by all parties.

It is recommended that the "beneficiary pays" part of the process be separated from the Regulatory Test proper. If the augmentation passes the Regulatory Test, then the proponent does 2 things in parallel:

- commences the project – this ensures earliest delivery of the benefits, and
- undertakes the "beneficiary pays" exercise

The "beneficiary pays" exercise should have a time limit of 3 months. If there is no convergence after that time, a "default" cost allocation (eg 50/50 generators and customers) applies.

2. Three methods for TUOS

It is our view that the move to 3 methods increases this asymmetry significantly, to the detriment of customers. The ACCC, as consumer watchdog, should require NECA to demonstrate benefits for the end-use customer which would more than offset the significant disadvantages.

We would propose that either the proposal for 3 methods be dropped, or the decision on whether to adopt it be delegated to the jurisdictions.

3. Threshold Issue

The threshold for "New Large Network Assets' of $10 million is considered too low for the Queensland network because:

- The costs of the process will be about $800,000 to $1 million per project -– this will increase the cost of the project by 10% - which is a very high administrative overhead to impose on customers;
- The only projects which will cause any material benefits to generators – to the extent that the cost allocation will result in any material allocation to generators – are line projects ;
- Due to the vast distances, line projects in Queensland cost more than $50 million.

The "cutoff" should be set at $50 million for the Queensland region.

4. Transfers between TNSPs

At no stage during the Transmission and Distribution Review process did NECA address or discuss the issue of Allocating TUOS across interconnectors or the related financial transfers, yet substantial code changes are being proposed.

We recognise that this topic must be addressed. We believe that, given the large sums of money which could be involved, discussions with the affected parties need to occur.

We believe that such a discussion is likely to result in a more workable framework than the model inherent in the proposed code changes.

5. Treatment of MNSPs

NECA has introduced a number of clauses in relation to MNSPs which are inconsistent with the treatment of generators with which MNSPs are competing. These clauses generally introduce principles and confer benefits on the MNSP which appear additional to those identified through the consultative process, including the work recommended by the NECA interconnector workgroup.

FORMAT OF RESPONSE

We have provided our response in 2 sections:

Section 1 responds to the ACCC's Issues Paper of September 1999.

Section 2 responds specifically to NECA's proposed amendments to Chapters 5 and 6 of the NEC.

In section 1, we identify some **philosophical and practical problems** with NECA's proposals.

We have, nonetheless, responded in Section 2 to proposed code changes even in areas where we have a major concern about the underlying approach. This should not be construed as acceptance of the NECA approach.

SECTION 1 ACCC Issues Paper

Some Background

Powerlink is responsible for developing, operating and maintaining the transmission network in Queensland, and our comments reflect the practical challenges of doing this in a region where:

- the "grid" is a long, thin backbone (1700kms from Gold Coast to Cairns)
- the loads are geographically dispersed, but with 60% in the SE corner.
- Most of the generation is in the centre of the State
- The grid has NO overcapacity – and indeed has some undercapacity for current loads (i.e. constraints)
- The load growth is projected to be 3.8 % p.a.
- Due to the above constraints, and the relatively tight supply/demand balance, the average pool price is much higher than in other regions (which means that customers perceive they are not seeing benefits from competition reforms akin to other States)

The effect of transmission augmentation in this environment is to deliver significant benefits to customers – with the largest contribution BY FAR being lower pool prices driven by increased generator competition as network constraints are removed.

We note with considerable concern the minimal recognition (non-recognition?) of this source of benefit in the work done by the ACCC, NECA and their consultants, who are clearly operating in a very different paradigm.

We have been able to do a preliminary analysis of the most recently completed (Nov 98) major augmentation in Qld – which clearly demonstrates these benefits. It also demonstrates the shortcomings of the proposed NECA methodology, and possibly the Regulatory test as well.

We believe that real life examples like this – rather than theoretical assertions, or references to very dissimilar networks (PJM, NZ) – MUST be used by NECA and the ACCC to test the validity of their proposals before imposing them on the NEM (and potentially reducing real customer benefits)

Responses to Specific Questions

4.1 Transmission network pricing

4.1.1 Existing arrangements

Are the proposed Code changes sufficient to encourage networks to negotiate and provide generator access services?

Powerlink has negotiated many such agreements in recent years as new generators are connected to the Qld grid, under the existing arrangements. We don't believe there are any significant problems, however neither Powerlink nor the generators have been able to structure a "firm access" contract.

The Code changes do not address the issue of developing a sufficient framework for negotiation of firm access. The NECA review did not include dealing with this issue as part of its terms of reference but has pre-empted a future review relating to this topic.

In the meantime, meaningful negotiations between generators and TNSPs are not likely to result in convergence. Other uncertainties are likely to further stifle negotiations on this issue, e.g.:-

- Possibility of nodal pricing and TCCs;
- Widely held view that access hedges ought to be a 3rd party insurance service.

Is there sufficient clarity to distinguish between the unregulated generator access services and the regulated generator negotiated use of system service (and any associated assets and revenues)?

Again, Powerlink has also been successful in recent years in winning the business of developing the unregulated connection assets (between the generator and the grid) for many new generators (and loads) . We have no difficulty in separating the assets and the commercial arrangements.

The Code changes identify the access contracts (hedges) as contestable services (refer to Clause 6.5.3(a)). As detailed above, there appears little chance for satisfactory negotiation on this issue under the present and proposed code provisions.

4.1.2 Who should pay TUOS?

Do interested parties believe that recovering the costs of the existing network from network customers minimises the distortions from recovering sunk costs?

In our original submission to the NECA review, we identified that we were neutral – as long as someone paid – but we provided logical arguments why customers should pay for the network – sunk and future.

Would the recovery of a proportion of the sunk costs from generators be less distortionary?

We also pointed out that Qld actually had a “generator pays a proportion” regime – based on LRMC to give locational signals - for 3 years from 1995 through 1997. Our experience was that the “generator pays” component was volatile – and distortionary – each time a new generator entered the grid.

<u>As the only entity which has practical experience in such a model , we would be happy to explain our experiences in more detail to the ACCC</u>.

Could the framework for recovering sunk network costs from customers also be applied to generators? That is, allocate a proportion of existing network costs to generators and allow individual, price sensitive generators, to negotiate discounts?

From our perspective, we need to receive our total revenue cap. Thus, discounts to anyone must be balanced by higher payments from someone else . And we have yet to meet a generator which is not price-sensitive, but we live in hope !!

If sunk costs were to be allocated to generators on a postage stamped basis as they are to customers, generators could pass them on to customers as increased energy costs. This would change the TNSPs performance measure (c/kWkr to customers) may not result in net benefits to customers.

Do interested parties believe that NECA's proposals introduce more "market like" disciplines into network investment planning processes?

Not really. Powerlink already uses something very similar to the proposed Regulatory test to establish that benefits outweigh costs for all major investments. And using demand side management in conjunction with distribution corporations is a well-established approach in Qld to deferring augmentations a number of years.

All major augmentations result in "winners" and "losers" as our real life example – Attachment 1 in Section 2 of our response – illustrates.

The 'losers' have a strong commercial incentive to delay the augmentation (market-like behaviour?), and the NECA process – largely due to the wide variability of possible plausible outcomes for who pays – will aid and abet this behaviour, thereby delaying benefits to customers.

Please see Section 2 of our response for a detailed discussion of the shortcomings in the proposed process, and a suggested process improvement to overcome those.

Are NECA's proposals likely to be consistent with future directions of network pricing in the NEM?

This is a leading question as it pre-supposes that nodal pricing is a future direction.

Are NECA's proposals sufficient to get market participants to reveal the extent of the benefits they will receive from a new market network investment?

Yes – but revelation is not the problem. The NECA approach requires pool modelling of a range of plausible generator bidding scenarios, and as these get published, all will be revealed.

However, each scenario will deliver a different answer for who benefits, and by how much. <u>Which one should be used?</u> The (naïve) view in NECA's report was that the parties will "converge" to an agreed sharing.

As our real life example shows, the upstream generators are beneficiaries under one plausible scenario, but are losers under another plausible scenario (which, incidentally, closely reflects the observed outcomes since the new line was commissioned).

The commercially justifiable position for these generators would be to argue they would be losers under one plausible scenario, and therefore pay nothing.

Under the NECA process, this would lead to a Dispute Resolution exercise where the pivotal issue is which set of assumptions of future generator bidding and operating behaviour is correct!!

The proposals do not adequately address other issues which will increase the incentives for "winners" to frustrate the process, viz:

- Most (if not all) justifiable augmentations may well be justified on customer benefits alone – why would a generator reveal its real costs if doing so would be to its detriment?; and
- The free rider issue is not adequately dealt with. A generator is unlikely to sign off on TUOS for the life of the investment (40 years) only to have its benefit eroded or reversed by a later new entrant

Alternatively, are the proposed arrangements likely to lead to illicit behaviour etc?

Illicit? probably not; but, as outlined above, the “losers” from an augmentation have a strong commercial driver ($ millions per week, perhaps) to delay the augmentation. And the parties whose status (winner/loser) depends upon which set of assumptions are used for generator bidding behaviour, can be expected to argue for the scenario which minimises their costs.

The real losers will be the customers who are denied the benefits (eg lower pool prices) whilst the process is delayed – the process actually has no defined end-point, or default cost allocation (eg 50/50)

Will regulatory responsibilities be fragmented etc?

The dispute will be about which set of assumptions for future generator bidding and operating behaviour are correct. Why would the ACCC – or anyone – want to own that problem?

Administrative simplicity?

We have commented on this at length in Section 2 of our response.

The process will facilitate delays by the disaffected, and insoluble (?) disputes on who pays.

We have also commented at length in Section 2 on the unjustifiably high costs of the process, and the inappropriateness of the $10 million threshold for the Qld network.

The process will cost at least $800,000 - $1,000,000 per project. This is an unconscionable 10% impost on a $10 million project – a cost which customers will ultimately bear.

The threshold in Qld needs to be at least $50 million - see Section 2 for more details on this.

Regulatory Test

We are deeply concerned at the thinking in the ACCC staff paper on the issue of whether pool price outcomes should be recognised as benefits of an augmentation. In fact, the Commission's Draft Regulatory Test for New Interconnectors and Network Augmentation (September 1999) would, on first reading, support the concept that a reduction in pool prices signals improved market efficiency and hence net benefits to the market.

In our real life example – supported by "after the fact" comparisons – show that these are by far the largest source of benefits to customers from augmentations which remove network constraints (that is, transmission line projects in the long, thin Qld grid)

The major customers in Qld have challenged us as to why this particular augmentation was not delivered sooner – these customers would rightfully be dismayed if the test promulgated by the ACCC prevented or delayed such a project.

A recurring complaint from contestable customers in Qld is that the NEM has not delivered them benefits like their counterparts elsewhere – and network constraints are a contributing cause to the higher pool prices.

It is a fact of life with the layout of the Qld network, the geographical disposition of generators and major loads, (and the portfolio ownership of generators in Qld) , that transmission augmentations remove constraints , which cause increased generator competition, which results in much lower pool prices.

We believe this particular aspect of the ACCC's Regulatory test deserves more analysis and discussion.

Practicality

As outlined above, the process proposed by NECA is NOT very practical – despite the fact that practicality was meant to be one of NECA's criteria.

In their report to NECA, Ernst & Young undertook some pool modelling –

> *"to consider the practicality of using this approach as the basis of allocating the benefits of a specific transmission investment to participants"*

They concluded that "*the range of net benefits may be sufficiently narrow to allow a rational decision to be made regarding the net benefits of the proposal<u>, but that it may be much more difficult to determine individual beneficiaries on this basis "</u>*

We believe that the NECA proposed process needs to be modified as outlined in Section 2.

Stability

Yes – the beneficiaries will change over time, and in Qld, this is likely to include new entrant generators, who clearly should pay if they are determined to be beneficiaries.

The ACCC's observation that benefits are accrued " to customers as competition between the generators leads to a reduction in the pool prices" is absolutely correct, and why we believe they should be duly recognised in the Regulatory test.

4.1.3 How should TUOS be levied

Do interested parties believe that a move to long run marginal cost (or utilisation adjusted) pricing represents a significant improvement in transmission pricing?

Not for customers. Major customers currently perceive that transmission pricing is an area of "information asymmetry" for them, because it involves a complex methodology.

Thus, the idea of having 3 different methodologies will be seen as a substantial worsening of the information asymmetry, coupled with an increase in the transaction costs for calculating the 3 methods – which ultimately pass through to customers.

NECA has not undertaken any analysis which demonstrates that the benefits to customers outweigh the significant added costs and disadvantages.

Do interested parties believe that the proposed pricing arrangements will ensure that network customers face charges that accurately reflect the needs for new investment at each connection point?

As mentioned, there has been no analysis performed to demonstrate such an outcome, and in the absence of analysis, any claimed benefits are purely speculative.

By using both short run (reflecting losses and constraints) and long run pricing methodologies, will there be over signalling of new investment at constrained parts of the network?

Whilst this is a possibility – our earlier comment applies – no analysis has been undertaken of real life Australian networks to demonstrate this problem won't (or will) arise.

We would expect the use of LRMC to introduce significant volatility in pricing – to the detriment of customers seeking to enter multi-year power purchase contracts.

Do the proposed Code changes provide sufficient guidance to require networks to adopt efficient prices from within the cost ranges?

No. The decision appears to be a judgment call for the TNSP, with review by the ACCC.

4.1.4 Summary of proposed changes

Do interested parties believe that the proposed Code changes reflect the findings of the NECA review?

No. There are some fundamental anomalies

(a) financial transfers between TNSPs - there has not been any real consultation on this with the TNSPs and the jurisdictions.

(b) Payments to market NSPs and generators for network savings – never addressed in the NECA review; introduces benefits to some participants which are unsubstantiated; provides virtually unlimited access to regulated monies without any form of Regulatory test

(c) 2% price cap – if the purpose of having 3 methods for calculating TUOS is to deliver better signalling, how is this achieved by damping the signals with a price cap?

We have included a detailed identification of these, and other anomalies, in Section 2.

4.2 Distribution network pricing

No comments.

4.2 Price negotiation framework

Are the proposed Code principles and regulatory arrangements sufficient to guide the negotiation process, in particular where one party (ie the network) is a monopolist and likely to have an information advantage?

The proposed changes require the NSP to cost-justify its charges. If the applicant was not in competition with the NSP, then this would seem reasonable. A range of participants – local generation, MNSPs – have claimed to be in direct competition to the NSPs. Under those circumstances, why should an NSP be required to disclose its costs to a competitor?

Is it reasonable to allow some users to negotiate discounts but to require other users to bear the costs of the discounts?

Firstly, it is necessary for the NSP s to obtain their revenue cap – thus, a discount to 1 user must be collected from others. It is arguable that non-economic bypass is not in the economic interests of the community, and this would support discounts to avoid such bypass.

Is it reasonable for negotiations on higher service standards to be subject to the negotiation framework yet price discounts are not?
The NECA Report envisaged that price negotiation would occur only in exceptional circumstances such as to avoid uneconomic bypass. In such instances, failure to negotiate would lead to a less favourable outcome for the NSP involved, hence adequate incentives for negotiations exist.

What sort of information should be publicly released?

To the extent that the revenue from the negotiation will impact the calculation of regulated revenue to be collected from others, that amount will have to be disclosed.

Is this negotiating framework sufficient to ensure that networks are limited in their ability to cross subsidise some customers at the expense of others?

More fundamentally, this comes down to an issue of whether the NSP should apply marginal (incremental) costing or average costing. The marginal cost of providing higher service standards might be very low if the network has spare capacity, but very high if an augmentation is needed.

Should networks have the ability to negotiate lower standards than those specified in the code?

Provided that the service standards for a TNSP are not set by the ACCC on a “one size fits all” basis, then rational service standards should evolve.

4.4 Service Standards

Do the proposed code changes fully implement the findings of the NECA transmission and distribution review?

Yes. However, for TNSPs the service standards which the ACCC sets as part of the revenue determination are key. These needs to avoid a “one size fits all” approach, and be tailored to each specific part of the network.

Do the Code changes impose sufficient obligations on the networks to establish clear and measurable service standards etc?

Yes – for TNSPs, when applied in conjunction with the ACCC”s Statement of Regulatory Principles.

Has an appropriate balance been obtained between networks and regulators etc?

For TNSPs, yes – the ACCC can review/modify the TNSPs proposed standards at each reset.

Are the responsibilities and powers of regulators been clearly defined?

For TNSPs – yes – by virtue of the ACCC’s Statement of Regulatory Principles.

4.5 Embedded Generation

General comments

The proposals for TUOS rebates for embedded generators have the potential to create "gaming" of the definition. This is because:

(a) the definition of the boundary between transmission and distribution is arbitrary.
(b) certain parts of some distribution networks are essentially "transmission in nature" (subtransmission), and can support a large connected generator.
(c) There is no size limit on the definition of embedded generator.
(d) Network assets which are currently defined as transmission can readily be "converted" to distribution assets.

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SECTION 2   Response to the NECA Code Change Document

In formulating this response, we have firstly provided the rationale for the suggested changes, and then provided the suggested changes to the wording.

This is necessary because some of the proposed code changes reflect processes which contain shortcomings, which cannot be simply corrected by a change of a few words.

Overview

Given that the wording of the code depends upon the integrity of the underlying principles and processes, it is necessary to address the fundamental shortcomings in those principles and processes in order to appreciate the consequent recommendations for revising the wording of the code changes.

Perhaps not surprisingly in such a large undertaking there are significant anomalies in the wording as proposed.

We have categorised our comments into 6 different aspects :

A. The process for advancing new large augmentations (clause 5.6.2)

The process as defined by the wording of the proposed code changes contains fundamental competition problems. It will, if implemented, aid and abet anti-competitive behaviour by disaffected participants or interested parties, to the detriment of electricity consumers at large.

We reference a real life example of the most recently completed major augmentation in Qld to demonstrate the inherent problems with the proposed process.

We have suggested an alternative, which does not change the underlying principles, but which minimises the opportunity for anti-competitive behaviour and aims to ensure that customer receive benefits at the earliest time.

B. High transaction costs of the process

The Regulatory test and “beneficiary pays” process will impose significant costs on the Network Providers, which, being legitimate costs of the network businesses, will be borne by customers. These costs are likely to be around $800,000 to $1,000,000 for each augmentation project, which in the case of a $10 million project, represent an added cost of 10%.

This is far too significant a cost imposition to be ignored.

We suggest that the definition of large project be revised to be $50 million or higher, and provide arguments which demonstrate why the costs imposed on lower value projects far outweigh any benefits the process might deliver to end-use customers.

Also, the wording in relation to cost allocation needs to be revised – as it stands, EACH small project will require the same treatment as a large project, and we understood that this is not NECA's intent.

C. Fundamental inconsistencies

There are several instances where the proposed code changes are inconsistent with each other, or introduce inconsistencies with the existing market arrangements. These include providing access to regulated revenue without a need to undertake the Regulatory test and certain treatments of MNSPs which are not available to the generators with which they compete.

In a number of these cases, the proposed code changes have not been discussed or debated as part of the NECA Review.

D. No consultation

The majority of proposed code changes emanate from the NECA Review which went through an extensive consultation process.

However, there are some key clauses which have **never** been addressed, discussed or debated in any part of the NECA Review – they have simply appeared in these code changes. The most important ones relate to financial transfers between NSPs for Interconnectors.

We recognise that this topic must be addressed. The appropriate way to do that is for NECA to arrange discussion on the topic so that the underlying principles can be established, and the practicality of the models tested with the affected parties BEFORE attempting to codify the matter.

This topic involves substantial financial sums and, will also require consultation with the jurisdictions.

In summary, a lot more consultation is needed, and we now understand that NECA accept this.

E. Transmission pricing - 3 methods of cost allocation

We believe that the imposition of 3 methods adds costs – borne by customers – which are not offset by benefits to customers. The use of 3 methods also significantly increases the "information asymmetry" between market participants and electricity customers, in an area where this asymmetry already adversely affects customers in their contracting for electricity purchases.

In essence, the imposition of 3 methods is anti-customer.

F. Other

These are essentially minor drafting matters.

Detailed Reasoning

A. The process for advancing large new augmentations (clause 5.6.2)

The **fundamental problem** rests with **the "Beneficiary pays" part** of the process and not with the Regulatory Test per se.

The problem arises because:

- a major network augmentation – by overcoming existing transfer constraints – will create "winners" and "losers" among market participants

  (In the real life example of the most recent major network augmentation in Qld, the "losers" are the generators downstream of the transfer constraint which the augmentation alleviated. They lose volume to the more competitive upstream generators, and also a lower pool price due to the increased competition from upstream)

- The "losers" will lose significant $ once the augmentation is implemented; and can retain significant $ if the augmentation is delayed. There is therefore a **strong commercial incentive for the "losers" to seek to delay the augmentation.**

(In the real life example, the incentive could be more than $1 million per week of delay, which would otherwise flow to electricity consumers)

- The **"beneficiary pays" part** of the process – as currently defined – provides **ample opportunities for the "losers" and "cost-avoiders" to delay the whole augmentation** (not just the allocation of transmission charges). The process – as defined – is based on assumptions of generator behaviour, which are easy to challenge; the process can go on indefinitely (no time limit) as "losers" challenge the proponent to model more and more different combinations of assumptions; and there is no "fallback" or default allocation which would bring the process to a firm conclusion in the absence of"convergence" by all parties

  NOTE: NECA's final review report postulates that all parties would "converge" to an agreed cost allocation. This is naïve – why would a participant which stood to gain a $1 million for each week's delay of an augmentation, ever want to "converge"?

  (In the real life example we studied, the range of benefits under plausible scenarios was determined. Even the scenario which had the lowest benefits was far in excess of the costs – yet, under the NECA proposed process, this augmentation could be delayed significantly by the "losers" and "cost-avoiders" – not on the grounds of benefits vs costs, but on the basis of the allocation of the costs to the "winners". Thus, even though it was obvious very early that the project should proceed, the "beneficiary pays" process – as currently defined – would see it delayed by the "losers" to their gain and to the considerable loss of the customers).

  In Queensland, the problem is exacerbated by the ownership of generation "portfolios" – a single Code participant may own a generator which is a "winner" from an augmentation, and another which is a "loser". Ownership of the "winner" enables the participant to exercise the full gamut of dispute procedures, delaying the augmentation and thereby extending the gains currently being made by the "loser" generator.

  We could expect that, in future, ownership of generation portfolios across regions will increase the incidence of this problem.

  1. **The inherent process flaws**

     The "bundling" of the "beneficiary pays" exercise into the Regulatory test itself.

The regulatory test enables the proponent to demonstrate that benefits exceed costs for a range of plausible scenarios. It is recognised that the modelling of generator bidding behaviour is a very inexact science, and that the assumptions can be readily challenged. By allowing a range of plausible scenarios to be considered, the Regulatory test attempts to accommodate this reality.

By contrast, the "beneficiary pays" exercise requires a single answer i.e. it must be determined by a single set of assumptions of generator behaviour. This is clearly going to be contentious – as outlined above, even those not required to pay, the "losers", can frustrate and delay the process by challenge. If the "winners" include generators (e.g. upstream generators), then they have a commercial incentive to argue for a minimal allocation of the costs (vs costs allocated to customers). Again, this serves to delay the augmentation.

(In the real life example we examined, in all scenarios the overall benefits far outweighed the costs and in all scenarios the customers were "winners" – this alone should be enough for the project to proceed forthwith.

However, the downstream generators, who were the "losers"` in all scenarios have a strong incentive to frustrate the process, and can do so because the process allows them to challenge the cost allocations, even though they will bear no costs.

Further, some scenarios show the upstream generators to be "winners" (they gain 15% volume but the pool price decrease is less than 15%) whereas other plausible scenarios show the same generators to be "losers " (the 15% volume gain is more than offset by a pool price decrease of more than 15%).

This modelling – which would be publicly available – provides the upstream generators with a basis for arguing that they, as potential losers in some scenarios, should pay nothing.

2. There is no 'default" cost allocation

If there was a "default" cost allocation, and a time limit, then the process could reach a firm conclusion.

A "default" cost allocation is one where the proportions for cost allocation are codified e.g. 50/50 split between generators and customers.

The proposed process is shown diagrammatically in Figure 1.

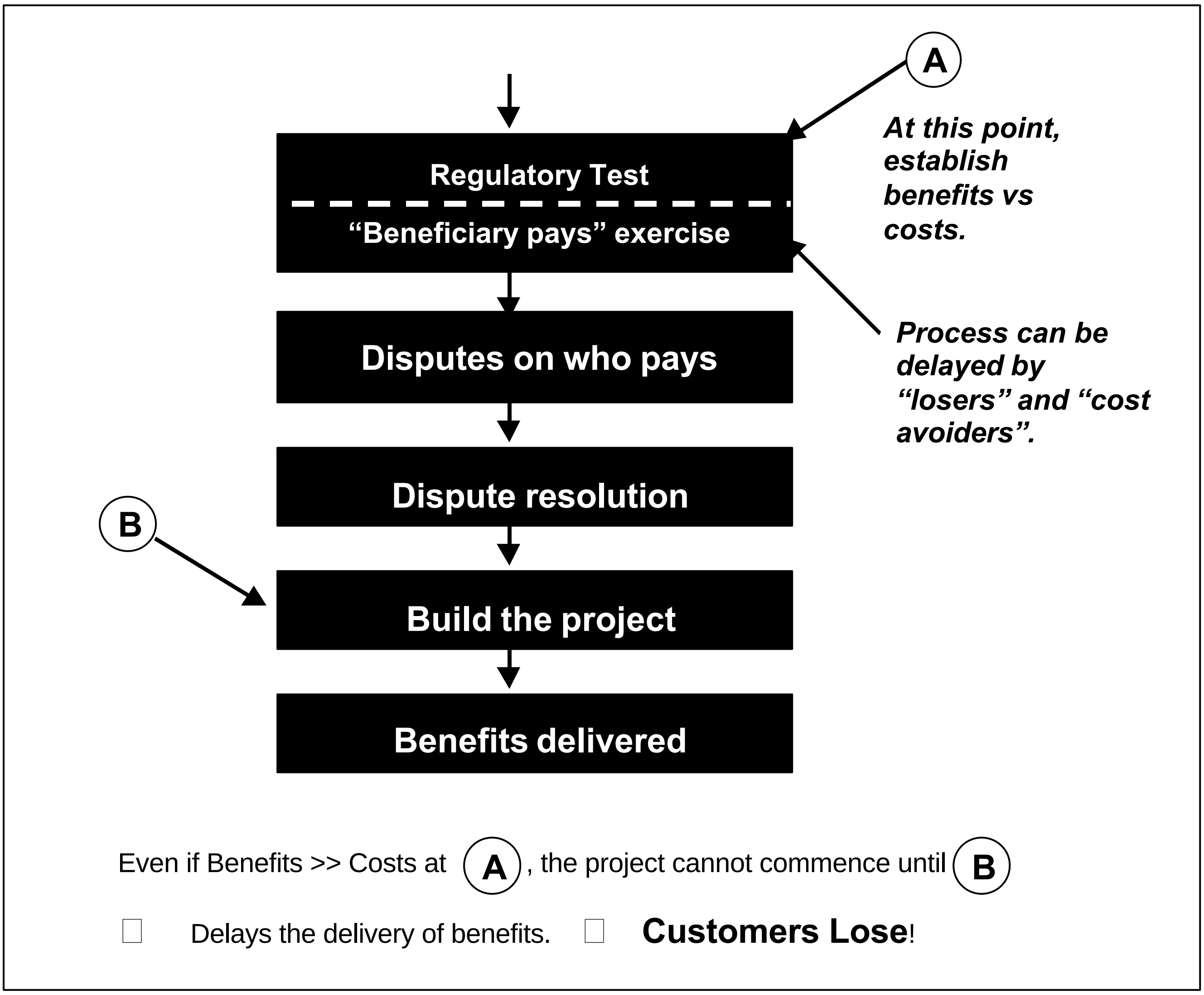

Figure 1 - Proposed NECA Process

The Solution

1. **Separate** the "beneficiary pays" part of the process from the Regulatory Test proper.

2. If the augmentation passes the Regulatory test, the proponent does 2 things **in parallel**:

   (a) commences the project – this ensures earliest delivery of the benefits, and

   (b) undertakes the "beneficiary pays" exercise

3. The "beneficiary pays" exercise to have a time limit of 3 months.

4. If there is no convergence after that time, a "default" cost allocation (eg 50/50 generators and customers) applies.

This is shown diagramatically in Figure 2 below.

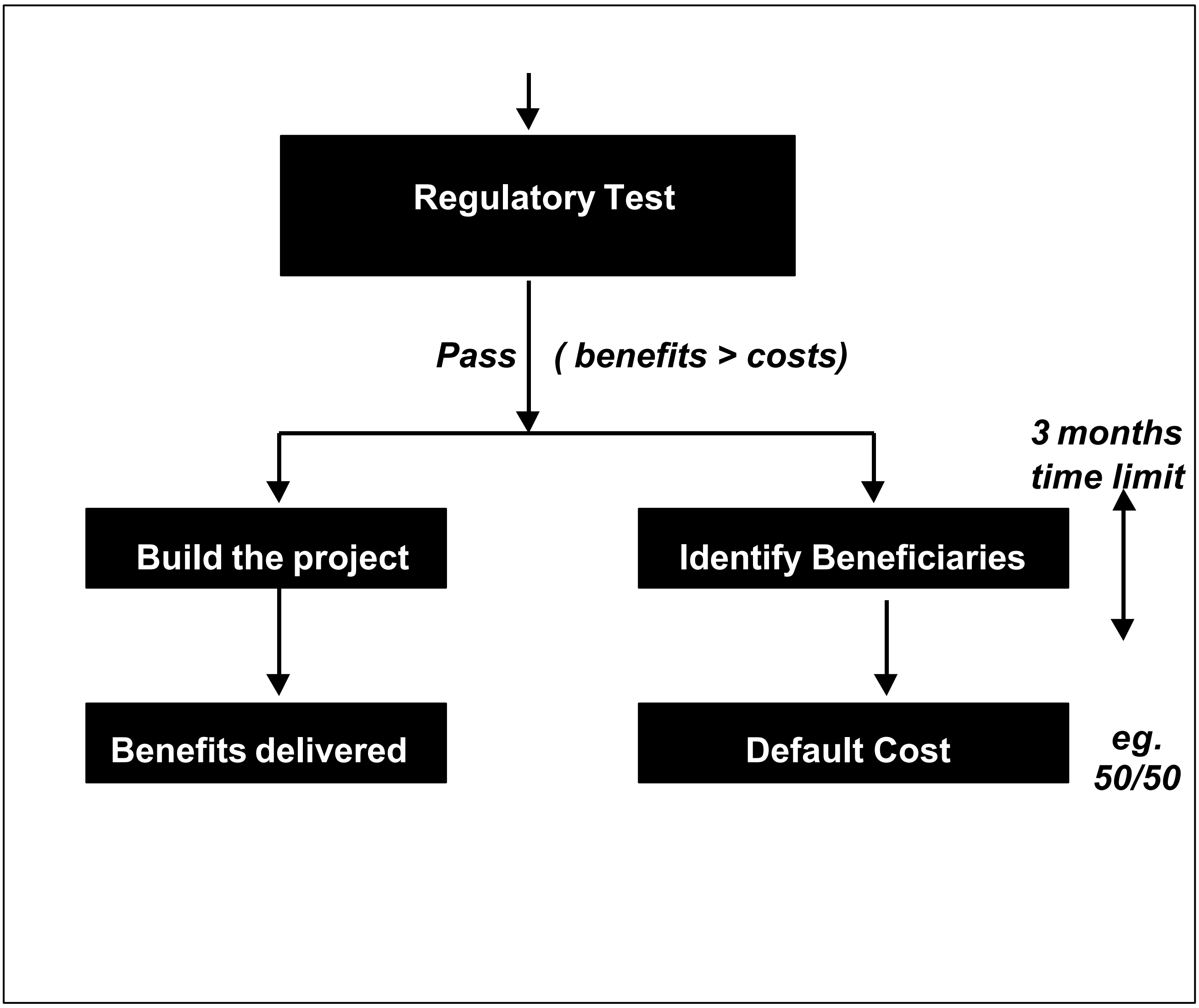

Figure 2 - Suggested Revised Process

Required code changes

Delete **clause 5.6.2.(g) (2)** and delete the words *"and allocation*" in the final para of **5.6.2 (g**)

Replace **clause 5.6.2.(h) (2) B and C** with a new clause B
- "*whether the preferred option is to be a fully funded network option"*

(The above changes separate out the cost allocation part of the process).

Add a **new clause 5.6.2 (j1)** – to require the NSP to undertake the "beneficiary pays" exercise (unless it's a fully funded option) and publish a report.

Add a **new clause 5.6.2 (j2**) – to enable ONLY those participants required to pay for the augmentation to make representations to the NSP within 40 business days and for the NSP to respond within 20 days.

Add a **new clause 5.6.2. (j3**) – to set a default cost allocation if there is no resolution after 3 months from the publication of the above cost allocation report.

(The above changes give effect to the "beneficiary pays" exercise)

In **clause 5.6.2 (k)**

Change *"must arrange for*" to *"use its best endeavours to arrange for"*, and change "*agreed time"* to "*recommended time"*

(Even with the process changes suggested above, the dispute procedures take the control of the overall timetable away from the NSP – thus the NSP can only use best endeavours to meet the proposed timetable)

Finally, the following changes are needed in clause 5.6.2 to **avoid inconsistencies and improve clarity.**

Clause 5.6.2 (f) (1)

This sub clause should be deleted. It makes no sense as only a single option can satisfy the Regulatory test. The wording in clause 5.6.2 (f) proper already imposes the obligation to consult on possible options, including demand side and generation.

Clause 5.6.2.(f) (2)

After "*to consult*" add "*or comply with clauses 5.6.2 (g) through (m"*

(This adds clarity – we understand that NECA did not intend for small projects or fully funded options to be subject to the processes in (g) through (m)

Clause 5.6.2. (f) (2) (A)

Replace "*Generator or MNSP*" with "*Code participant and/or interested parties"*

(The funding of a network augmentation should not be limited to some participants – a retailer and/or a customer may wish to do so. The clause as it stands is fundamentally anti-competitive).

Clause 5.6.2 (k) (1)

Replace *" proposals to which clause 5.6.2 (l)"* with *"disputes raised under Clause 5.6.2 (l)"*

(For clarity, the dispute resolution reference should be limited to those proposals where a dispute was actually raised, not all proposals)

Clause 5.6.2 (k) (2)

This clause should be deleted.

(Only 1 option can satisfy the Regulatory test, by definition)

B. High transaction costs of the process

The "cutoff" of $10 million is too low for the Queensland network because:

- The costs of the process will be about $800,000 to $1 million per project -– this will **increase the cost of the project by 10%** - which is a very high administrative overhead to impose on customers.
- The only projects which will cause any material benefits to generators – to the extent that the cost allocation will result in any material allocation to generators – are line projects
- Due to the **vast distances**, line projects in Queensland cost more than $50 million

The "cutoff" should be set at $50 million for the Queensland region.

Required code change

Chapter 10 glossary – "*new large network asset*"

After *"$10 million*" add " *or in the case of Queensland , $50 million*"

Also, the wording of the process for cost allocation for new small projects means that the full blown analysis – at enormous cost – would be imposed. We understand that this is not NECA's intent, and the wording needs to be changed to reflect the intent that small augmentations NOT be subjected to the costly consultation processes and Regulatory tests.

Clause 5.6.2. (f) (2)

Change as outlined in section A above.

C. Fundamental Inconsistencies

The following clauses contain fundamental inconsistencies

C1. Treatment of MNSPs

NECA has introduced a number of clauses in relation to MNSPs which are inconsistent with the treatment of generators with which MNSPs are competing. These clauses generally introduce principles and confer benefits on the MNSP which appear additional to those identified through the consultative process, including the work recommended by the NECA workgroup.

Clause 5.5 A (g) (2A)

This clause should be deleted. This clause seeks to provide MNSPs with unsubstantiated access to regulated monies on the obscure basis that the MNSP's presence might reduce the future costs of the network. This benefit is not available to generators who could arguably lodge the same claim, there is no onus of proof that any actual future saving would occur (i.e. no Regulatory test), no onus to identify the beneficiaries of the future saving (i.e. no beneficiary pays test), and yet provides access to regulated monies.

The concept is inconsistent with the Regulatory Test which already has provisions for negotiated payments by the NSP for purchase of network services which are an alternative to a proposed network augmentation.

Clause 6.4.3 C (c) (5)

This clause should be deleted. This is related to the above clause (and another clause which has previously deleted).

Clause 5.5 A (g) (1A)

This clause should be deleted. It attempts to provide an advantage to MNSPs which is not available to generators, and is inconsistent with the regulatory arrangements whereby the ACCC sets service standards and parties may negotiate for a higher service standard.

Clause 5.5 A (i)

Payment under Clause 5.5 A (g) (3) would be an excluded service and therefore not contribute towards the aggregate annual revenue requirement. This clause should be deleted.

Clause 6.4.3 B (b)

Delete the words inserted in the 18 August variation "*other than to clause 5.5 (g) (2)*". Again, these are inconsistent with the arrangements elsewhere in the Code and inconsistent with NECA's stated intentions.

Clause 6.4.3 C (a)

As per the above clause. An MNSP embedded in a distribution network should be subject to the same principles.

For clarity, the following words should be added: "*For clarity, where a connection point with a Market Network Service Provider is the same location as the connection for other customers, costs being allocated under this clause relate only to the Market Network Service Provider and not to the remainder of the connection point customers*"

Clause 6.4.4 (b)

Same comments as per the above clause, including the need for the added words.

Clause 6.4.9

This clause should be reinstated. If the basic principle is that an MNSP is to be treated as a load in one region and a generator in another, then, for consistency, it should be so treated in relation to allocation of transmission costs.

Chapter 10 Glossary "*negotiated use of system*"

Delete *"or receive* " in (b). Related to several clauses above.

C2. Other fundamentals

Clause 6.4.3 A (c)

This clause should be deleted (or removed to the DUOS section). TUOS costs must NOT include distribution network investments.

Clause 5.6.3 (a) (4)

This clause should be deleted. Under clause 5.2.3 (g) (2) the relevant NSP can advise these requirements directly.

Clause 5.5 (j)

This clause – as currently worded – is inconsistent with the proposal that embedded generators are to be paid by DNSPs (and NOT TNSPs), and also appears to extend the payments for embedded generators to all transmission-connected generators.

Delete all references to "*Generators*" and to "*Clause 5.5 (f) (3)*" and the last 3 lines.

The amended clause should read *"Any payments to embedded generators under clause 5.5(h) are to be included as part of the aggregated annual revenue requirements of the relevant Distribution Network Service Provider, and are to be recovered in the same manner as payments to Embedded Generators under clause 6.13.3 (d)"*

Schedule 6.2 Clause 2.1 Station Establishment and Buildings

There is a substantial inconsistency in this section in that load customers are being apportioned a disproportionate share of the network costs through this allocation provision. Originally this clause was structured so as to prevent new customers getting a free ride through their new connection substation establishment and building costs being allocated to shared networks. However, deep connection provisions allow for appropriate allocations in these specific cases.

Powerlink, as well as a number of other TNSPs, currently apply pricing methodologies similar to Part C of Chapter 6 with the exception of this clause 2.1.

It is our view that retention of this clause as it stands will result in more distortionary outcomes than any other issues addressed in the NECA pricing review.

We suggest the clause be revised as follows:

"2.1 Station Establishment and Buildings

The majority of station establishment costs are included in the Transmission Network category. For example the cost of a circuit breaker includes associated busbars and isolators, secondary plant including remote control and secondary equipment, civil works, design installation and commissioning and project administration.

Additional station establishment costs includes only the civil works, roads and fences required for the establishment of the station while buildings include only the common station equipment and facilities. ~~These costs are to be recovered through connection charges~~.

~~In cases where a substation does not supply any load (ie either a switching station or a transformation station between two transmission levels) then these~~ These station establishment and building costs should be allocated on a simple pro-rata basis to each circuit breaker which terminates a line or transformer at the station and will therefore be included in the node to node costs of the transmission network.

~~For example an existing station which provided transformation only between two transmission voltage levels could be extended to supply load in which case the associated additional station establishment costs would be allocated to the connection category. Alternatively an existing station which only supplies load may be converted by the addition of transformation between transmission levels. In this case station establishment costs would be allocated to common service.~~

~~Station establishment costs for existing stations which provide a dual purpose shall be allocated as connection costs~~."

D. Significant "no consultation" issue

At no stage during the Transmission and Distribution Review process did NECA address or discuss the issue of Allocating TUOS across interconnectors or the related financial transfers, yet substantial code changes are being proposed.

We believe that such a discussion with the affected parties is necessary, given the large sums which could be involved.

We believe that such a discussion is likely to result in a more workable framework than the model inherent in the proposed code changes.

Required code changes

Clause 6.3.4 (b)

The original clause should stand. Allocations never discussed.

Clause 6.4.3 B (c) (ii)

Delete *"or financial transfers etc*". Such transfers never discussed.

Clause 6.4.3 B (d)

Delete "*other than a region*". Same reason as above.

Clause 6.4.3 C (b) (5)

Delete. Never discussed.

Clause 6.4.3 C (c) (2)

Delete. Never discussed.

Clause 6.7.4

Delete. Never discussed.

Schedule 6.4.9

Delete. Never discussed.

E. The 3 methods of cost allocation for TUOS (Schedule 6.4)

This proposed change is not beneficial to electricity customers:

(a) it will increase the operating costs of the TNSPs which are ultimately borne by electricity consumers, and

(b) it will increase the "information asymmetry" between customers and the code participants with whom the customers have to negotiate electricity purchases.

Under the current arrangements, there is 1 method for cost allocation, and, with the transmission and generation developments in Queensland, the allocations can change from year to year.

At a recent seminar with major customers, we have seen that even these annual changes – the direction and size of which are predictable by none but the exponents – represent a significant "information asymmetry" issue for the customers. It impacts the ability of the customer to truly assess the size of the risk of annual TUOS changes, and therefore the best way to deal with this in its power purchasing contracts.

The move to 3 methods increases this asymmetry significantly, to the detriment of customers.

6.4.3B Allocation of Usage Component of Customer TUOS costs

The NECA proposal to use the 3 customer allocation methods attempts to pinpoint an accurate pricing signal. However the methodology **will not** deliver this desired accuracy because:

- Method 3 (LRMC) is scenario/assumption based and very loosely defined. Repeatability is in no way assured;
- Clause 6.4.3B(c)(ii) requires the TNSP to select a single price in the calculated range based on judgment; this may well lead to disputation
- Clause 6.5.5 limits the price increase at any node to 2% above average. If the underlying rationale behind the new approach is to obtain better signalling, then an arbitrary price cap – which damps the signal – is totally inconsistent.

Prior to the Pricing Review, the most common customer complaint about the CRNP pricing was that it was too complex to understand. NECA's proposals have increased the complexity by an order of magnitude without improving the quality of the signal

For a customer, there are only costs and disadvantages in this step.

The ACCC, as consumer watchdog, should require NECA to demonstrate benefits for the end-use customer which would more than offset the significant disadvantages. This has not been demonstrated to date.

We would propose that either the proposal for 3 methods be dropped, or the decision on whether to adopt it be delegated to the jurisdictions.

F. Minor and cosmetic issues

Required code changes

Clause 5.2.3 (e1) (2)

This clause should be deleted. TNSPs do not have the ability to control fault levels – they are driven by generation development.

Clause 5.5A (d) (1)

After "*expected operation*", add "*including power flows"*

(This clarifies the required information)

Clause 6.1.4. (c)

This clause should be reinstated for clarity.

Clause 6.3.1 (a) (4)

Replace with "*common services which are services which cannot be allocated to users on a locational basis and are further defined in Schedule 6.2"*

(This clarifies that common services are not just those for maintaining power system security)

Clause 6.3.1. (c) (2)

Delete this clause.

(Operation and maintenance costs are not a class of transmission services)

Clause 6.4.6 (a)

Change reference to 6.4.3B to 6.4.3C – incorrect cross referencing

Clause 6.14.3(d) Standby Charges

It is suggested that a corresponding clause be added to Part C to provide for negotiation of standby charges for transmission connected generator/customer pairs.

Attachment 1 Real life example of a recent large augmentation CQ – SQ

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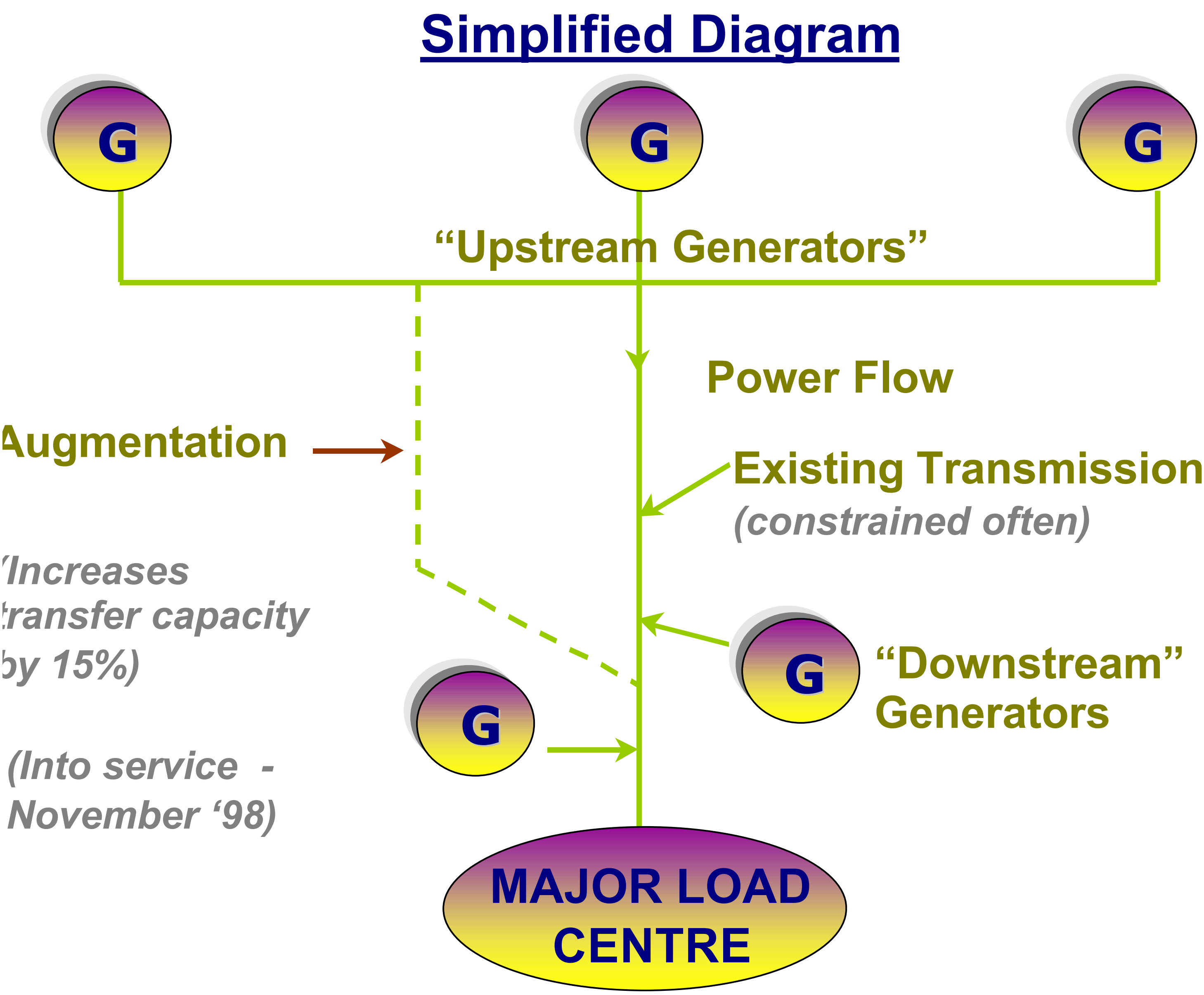
Attachment 1

Central Queensland – Southern Queensland Augmentation



Central Queensland – Southern Queensland Augmentation

Benefits vs Costs ($m per annum)

	Plausible Scenario ‘A’	Plausible Scenario ‘X’
Costs		
Increase in regulated revenue to TNSP (5%)	12.5	12.5
Benefits		
Increased reliability/security (VoLL = $5k)	5.0	5.0
Reduced Transmission Losses	7.0 – 10.0	7.0 - 10.0
Lower Pool Prices (due to generator competition)	8.0 – 15.0 (2% lower)	>100.0 (up to 30% lower)
Total Benefits	20.0 - 30	>100.0
Benefits: Cost Ratio	1.6 – 2.4	>8

Central Queensland – Southern Queensland Augmentation

Identifying the Beneficiaries

	"Winners" (Beneficiaries)	"Losers"
Plausible Scenario 'A' **Overall Benefits > Overall Costs**	Customers (reliability, lower pool prices) Upstream Generators (volumes up 15%; pool prices down < 15%)	Downstream Generators (lower volumes, lower pool prices)
Plausible Scenario 'X' **Overall Benefits >> Costs**	Customers (reliability, much lower pool prices)	Downstream Generators (lower volumes, lower pool prices) Upstream Generators (volumes up 15%; pool prices down > 15%)
'Interested Party' Perspective	A not-yet-constructed new upstream generator (100%)	