



Review of NEM Transmission Region Boundaries

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Overview

- Regulatory framework
- Review Issues
- Role of Region Boundaries
- Options
- Recommended Approach
- Boundary Principles
- Network Representation Issues
- Congestion pricing and incentive mechanics

Review Issues

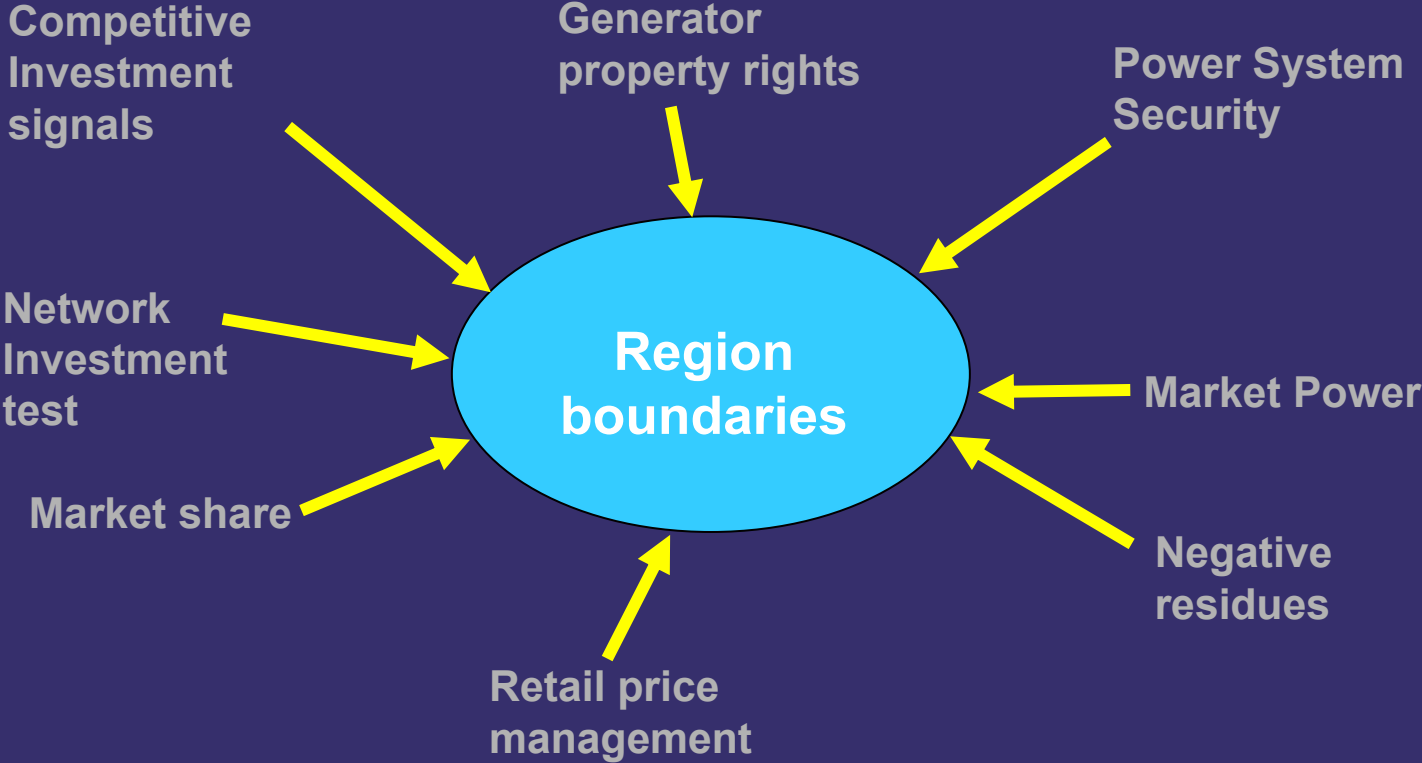
Two essential features of market are compromised

1. Moratorium on

- reviewing boundaries based on the current principles; and
- replacing the principles

2. Network Representation is in disarray

Interacting drivers



MCE Regulatory Framework

Roles of transmission:

- a transportation service from generation source to load centre;
- facilitates competition
- ensures secure and reliable supply.

Central and ongoing role for the regulated provision of transmission, with some scope for competitive (market) provision.

Investment decisions should be timely, transparent, predictable and nationally consistent, at the lowest sustainable cost.

Regulatory framework should maximise the economic value of transmission, including through the efficient removal of regional price differences in the operation of the NEM.

Regulatory Framework Instruments and Processes

Regulatory Test

- Market value
- Reliability
- (Competition)

Revenue reset determinations

Statement of Opportunities

Annual National Transmission Statement

Planning coordination & governance arrangements

Energy market prices (including region boundary definitions)

Role of Region Boundaries

Role of Region Boundaries

Basic function

- Set level of “granularity” of energy market representation of locational cost differences. e.g. at every node, by region ?

Why represent locational cost differences ?

- Influence **location** of **future** decisions
 - Investment
 - Market and plant operation

Note, boundaries do not of themselves create cost differences

This is idealistic as as in practice can alter bidding incentives

What is the likely level of locational price differences

Strongly dependent on network investment regime

- Modelling results demonstrate likely limited difference between nodal price and rational regional pricing in NEM

Inherently dynamic

- Boundaries unstable
- Hedging instruments must adapt

Other locational drivers are important

- Commercial common sense if facing congestion
- Network pricing
- Loss factors

Boundary Options and Issues

Holistic package

- Highly granular (nodal)
- Dynamic Regionalisation (status quo design)
- Low granularity
- Hybrid (Generator/Load)

Assessment

Economic efficiency

- Dispatch
- Allocative
- Investment

Commerciality

- Market disruption
- Liquidity
- Transaction Cost

Technical interface

Integration with broader regulatory framework

- Wholesale and retail

Highly Granular (nodal) + Firm Transmission Right Hedging

Criteria	Assessment
Pricing accuracy	High but subject to quality of FTR allocation and review (can be compromised by market power)
Commerciality	Low – Moderate. Better if clear and stable FTR allocation
Network management	Very Good incentives
Energy Market allocation	Potentially difficult – policy decisions re property rights, market power in auctions needed across market.....
Retail Policy consistency/ease	Low (disparate prices within jurisdictions) but can be managed with jurisdiction processes

Dynamic Regionalisation + Interregional Hedging

Criteria	Assessment
Pricing accuracy	Very good (subject to review and notice period)
Commerciality	Low – Moderate (implies regular boundary changes with current SRA hedging)
Network management	Moderate
Energy Market allocation	Not applicable (implicit intra-regional hedge + auctioned SRAs)
Policy consistency/ease	Low (disparate prices within jurisdictions) but can be managed with jurisdiction processes

Evolutionary Regions + SRA Selective Inter/Intra regional congestion management

Criteria	Assessment
Pricing accuracy	Very Good (potentially same as nodal but again dependent on allocation)
Commerciality	Very Good – Stable regions but relies on certainty of processes for certainty of allocations
Network management	Very high
Energy Market allocation	Potentially dependent on regulatory processes
Policy consistency/ease	Minimum disturbance

Hybrid – Nodal for Generation/Regional for Load

Criteria	Assessment
Pricing accuracy	High for major generation, poor for embedded, low generally for load
Commerciality	High for load Low – Moderate for
Network management	Good opportunities
Energy Market allocation	Requires central process as load price is averaged
Policy consistency/ease	High for retail price management

Conclusion and Recommendation

No case for radical change to regional concept

Within regulatory framework, retain concept of pricing congestion with:

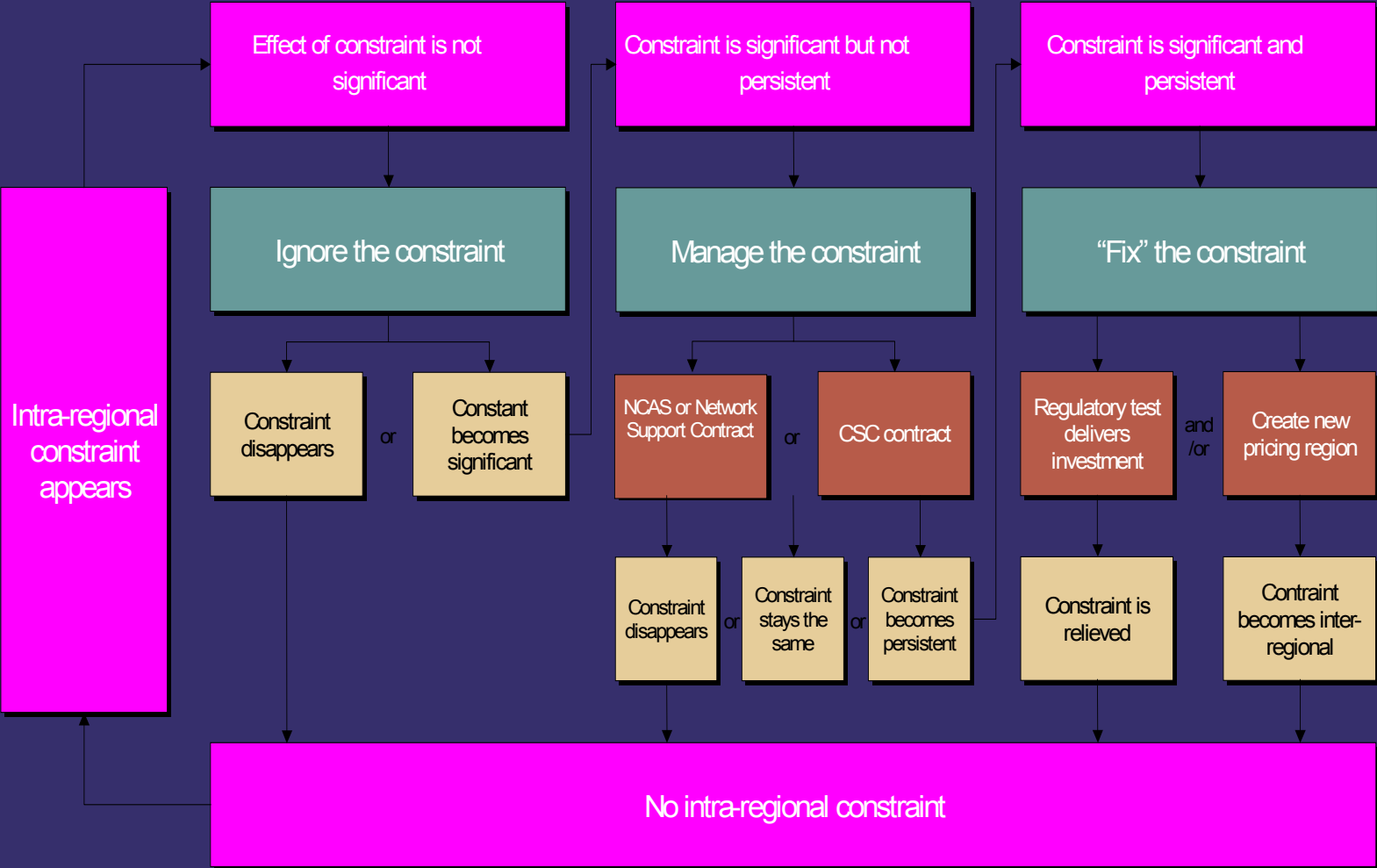
- Broad boundaries for persistent and material congestion
- Cost effective targetted and flexible pricing/incentives elsewhere as needed

Refining the role of Region Boundaries within NEM

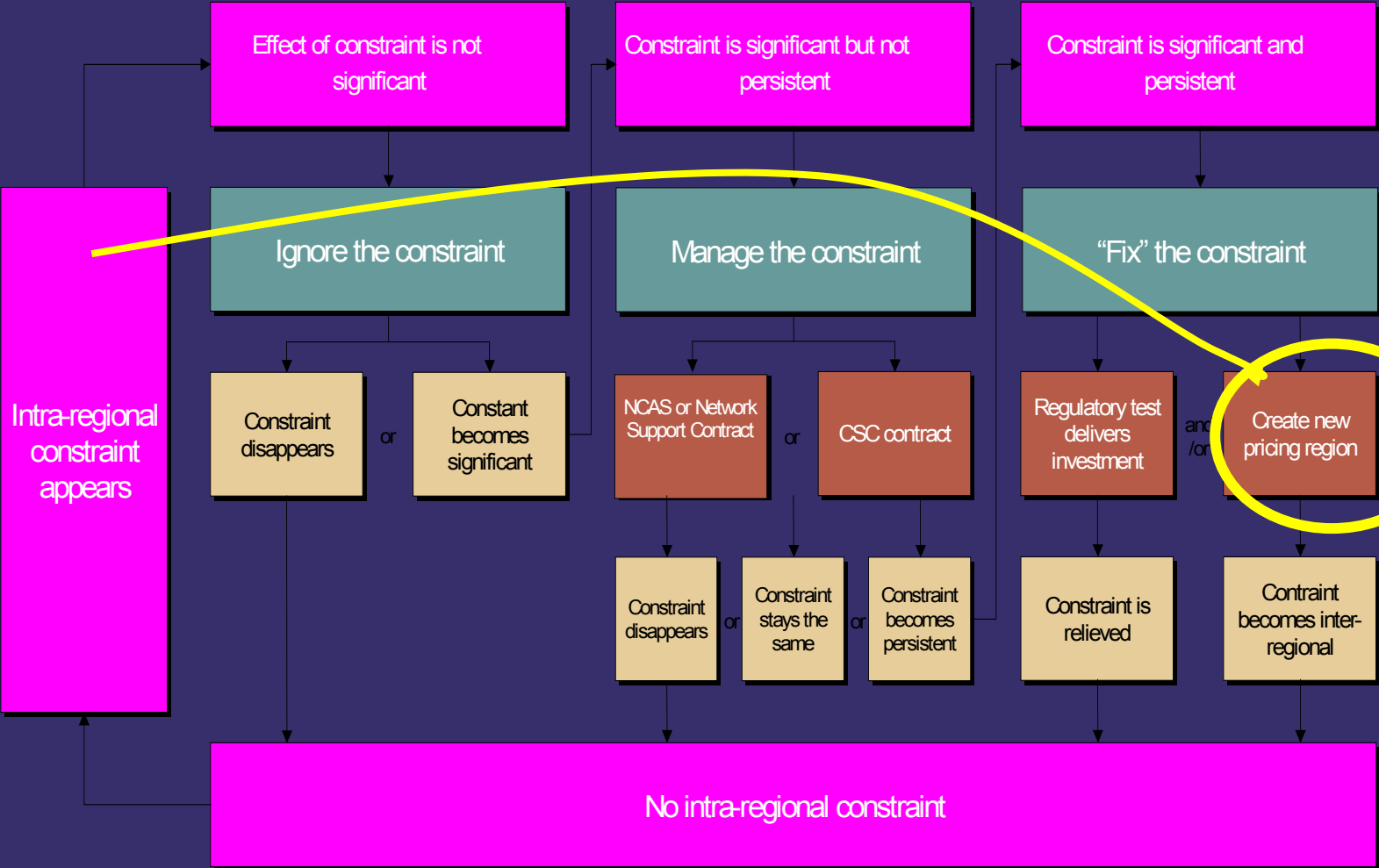
1. Mechanism to define boundaries of **material and persistent** cost differences
2. Position within framework to **maximise opportunity** for competitive response

Note - multiple roles of network (transport, competition, reliability) will determine role of network vis a vis generation & demand side

Overall framework



Overall framework



PRINCIPLES WITHIN THE NATIONAL ELECTRICITY CODE FOR FUTURE REVIEW OF REGION BOUNDARIES

Existing Criterion: Region Boundary Change

Currently: 50 hours per year constrained trigger for new region

But

- No measure of price differential
- No measure of size or scale
- No measure of value
- No indication of how long the constraint likely to remain
- Given that a new Region has major commercial and political implications, this is an inadequate criterion
- It is just too simplistic

Costs and benefits of regional change

Benefits

- Saving in network costs where generation locates to relieve constraints or defer investment
- Improved dispatch efficiency, and application of dynamic losses

Costs

- Transition costs (IT systems, reworking contract position)
- Cost of capital may rise if liquidity and market risks perceived to increase if regions perceived to be unstable
- Competition may strengthened or weakened by regional change
- A material net benefit gives case for regional change – but difficult to calculate

But, proposed framework including possible CSC can be a better solution, able to achieve similar results but more targeted and flexible

So threshold for new boundaries set high in conjunction with CSP / CSC

Our approach

Minimise transition costs

- High threshold means boundary change less common and if required yields big benefits
- Having infrequent reviews creates a window of certainty
- Sufficient notice to allow systems to be modified and time for contract positions to be adjusted

Ensure materiality

- Minimum region size
- Minimum price change
- Other solutions tested and compared
- Net effect is to only change Regions when there is material economic benefit

Summary of boundary criteria

Materiality

Dispatch Materiality – At least \$1M net dispatch benefit

Investment Materiality – A medium term price differential of 25% of the of the cost of a new entrant (say ~\$10/MWh for base-load, \$2-3/MWh for peaking)

Scale – At least 200 MW per region

A prospect of a market response

Schedule

3 years after a decision for a region to commence

Region to apply for 5 years at least

Intra regional contracting

DEVELOP PROPOSALS FOR INTRA REGIONAL CONTRACTING

In the absence of the proposed CSP / CSC mechanism, the hurdle for regional change would be lower.

Interaction with Regulation

Information for participants

Detailed market information on congestion available

Indication of justified network augmentations

Reporting of shadow prices

Consistency between Regulatory test and Boundary reviews

The Regulatory test to consider CSP / CSCs and new Regions as an alternative to network investment

At Regional Reviews, new network investment be considered

NETWORK REPRESENTATION AND MODEL

Role of network representation and model

Background:

Dispatch and pricing is based on mathematical model of network, load and generators

Model solved each 5 minutes for optimum economic outcome for *that* 5 minute dispatch

Network congestion may limit use of cheapest generation

Equations “tell” model of network limits

The issue

Construction of equations can impact solution

Multiple forms of equation in use – lacks consistency

No agreement about form that should be adopted

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Impact of different constraint forms

- Economic prices for future decisions
- NEMMCO management of power system security
- Commercial outcomes
 - Market share, price and settlement residue

Two central market concerns

Impact of lack of competitive discipline (market power)

Creation of negative settlement residues

Different forms of network equation create different discipline on bidding behaviour

Management of security

NEMMCO must keep actual network loading within limits

Accuracy of network representation is crucial

Less accurate – more ad hoc (safety margins etc) and less efficient

NEMMCO seeking control of all relevant physical parameters that determine network flows – only available from a direct physical representation of network

Direct Physical Representation allows market pricing and physical dispatch to be “decoupled”

Dispatch objective is key

Options

- Retain *current* 5 minute by 5 minute optimisation based on bids as presented to NEMMCO

or

- Amend with intent to enhance longer term market efficiency and control negative residues

Note - Form of network equation can be an instrument to change objective

Trade - offs

Negative residues

- Economic characteristic of marginal prices in looped network
- Clearly can be inhibited but ONLY at expense of not achieving current 5 minute dispatch objective
- Can be a symptom of inappropriate bidding (market power)
- Currently controlled (via a derogation)

Security management

We consider it would be difficult for NEMMCO to reach any other conclusion other than an equivalent of the Direct Physical Representation under the current Code

Conclusion and Recommendations (1)

- ✓ No basis to amend dispatch objective
- ✓ Confirm Direct Physical Representation form of equation
 - ✓ Allows physical dispatch and market pricing to be “decoupled”
- ✓ Maximises efficacy of management of security

- ✓ BUT in presence of inaccurately priced congestion (eg poor region boundary location) opportunity exists for “inappropriate” bidding and short term loss of efficiency

Conclusion and Recommendations (2)

Internationally, management of bidding incentives in the presence of congestion is a common problem

- Many alternatives are very heavy handed (eg PJM cost based price cap)

Option to limit some adverse effects with simple flow limit

- Should ensure clear instruction to NEMMCO from appropriate authority
- Recognise presence of network loops = complexity
 - Compounded with more loops
- Recognise inherent difficulty in limiting only economically inefficient outcomes

CSC regime offers alternative solution

DEALING WITH CONGESTION

(CSP/CSC Concepts)

***NOTE ON EXTRA SLIDES**

This presentation is based on the version presented in Melbourne, in which a number of points were simplified an/or clarified

It also contains a number of extra slides, which were not presented at either forum (marked by *)

These slides provide greater detail on various points, at the expense of some repetition

Basic CSP/CSC Concept

With consistent treatment of constraints a zonal market can be developed which:

- Allows a robust (eg nodal) market-clearing formulation
- Maintains a simple regional structure
- Deals with key constraints selectively using:
 - “Constraint Support Prices” (CSPs) broadly equivalent to LMPs
 - “Constraint Support Contracts” (CSCs) broadly equivalent to FTRs
- May be more or less complex than LMP/FTR, because, instead of one price per node
 - There is one price per region, plus one per binding constraint, and
 - Affected participants need to know their constraint coefficients

Implications

Potentially this CSP/CSC regime :

- Requires some new concepts to be understood
- Is both more general and more selective than LMP/FTR
- Allows more precise trade-offs between complexity, accuracy, and risk
- Creates a much broader range of market design options

BUT, since CSCs define property rights in a similar way to FTRs, essentially the same issues arise with respect to:

- The need for a process to allocate FTR/CSC rights
- The ability of network rents to sustain CSC/FTR allocations
- The potential for conflict over allocations, particularly where values are negative

*LMP/FTR vs CSP/CSC

The choice of dispatch optimisation/ market-clearing engine can be separated from that of commercial market design

A zonal market can be constructed in which participants have:

- The same effective price signals (energy +CSP) as in a nodal market, and
- CSCs equivalent to FTRs from their local to the relevant regional reference node (with FTRs between regional reference nodes)

This approach would give identical outcomes to LMP/FTR, IF

- Losses were treated identically
- CSP/CSC applied to all “NEO” constraints/terms
- CSP/CSC application to no “non-NEO” constraints/terms

But the CSP/CSC approach can allow a more general, and more selective , implementation, attuned to NEM circumstances

*History

Theory of consistent “constraint orientation” was:

- Described by “Constraint Orientation” report for NEMMCO (March 2003)
- Applied in “Constraint Representation” report for NEMMCO (January 2003)

The CSP/CSC concept has been developed over several reports:

- Basic concept developed for “inter-regional” constraints by “Gatekeeper” report for NEMMCO (March 2003)
- Concept extended to “trans-regional” constraints involving interconnector interactions in “Interactions” report for NEMMCO (June 2003)
- General application, eg to intra-regional constraints and non-energy terms in “Theoretical Framework” report for MCE (September 2004)

CSP/CSC Concepts in a Zonal market

In a zonal market:

- All generation/load in each zone faces the same price
- Optimal dispatch will constrain some participants on/off with respect to that price when constraints bind
- “Pay as bid” constrained on/off compensation is an option, but
- Consistent constrained on/off compensation can be provided by:
 - Declaring the constraint shadow price as a “Constraint Support Price” (CSP)
 - Having payments to/from all affected participants equal to:

$$CSP * MWGEN_p * COEFF_p$$

- With a “Constraint Support Contract” (CSC) this becomes:

$$CSP * (MWGEN_p - CSC_{ip}) * COEFF_p$$

(Where $COEFF_p$ = constraint/participation/contribution coefficient)

CSP/CSC Implementation

Implementing a CSP/CSC regime for a specific constraint requires:

- Definition of the constraint in the NEMDE 😊
- Derivation of constraint coefficients for participants 😊
(explicit in current NEMDE, implicit in a nodal model)
- Extraction of the constraint “shadow price” from the NEMDE 😊
- Agreement for participation by affected generators, interconnectors, ancillary service providers (and potentially loads / TNSPs)
- Establishment of CSCs with specific participants
- Establishment of a constraint rental pool
- CSP payments to/from pool
- CSC payments to/from pool

Explanation of Concepts

Since $COEFF_p$ is fixed for participant p , CSC could be defined as:

- $CCON_p$ MW of contracted constraint capacity, or
- $CGEN_p$ MW of contracted generation/transfer/access capacity

$$\text{Where: } CGEN_p = CCON_p / COEFF_p$$

- The former facilitates comparison between participants' CSC allocations
- The latter facilitates comparison with FTRs

The effective price signal for marginal production by p is a “Pseudo-Nodal Price”:

$$PNP_p = RRP - CSP \times COEFF_p \quad (\text{assuming coeff is for a } < \text{ constraint})$$

If CSP arrangements apply to multiple constraints:

- PNP equals RRP plus sum of CSP effects

*CSP/CSC Examples

The next few slides are modified from those for Scenarios A, B
and C
in Appendix C of the main summary report

(With some **highlighted** typographical
errors corrected)

These examples illustrate CSP/CSC mechanics

- The arcs here are conceptual, and do not necessarily correspond to a realistic network topology
- Price derivation is discussed briefly, but not related to underlying loop flows
 - Both aspects are discussed in Appendix B/C of the Theory report, and in earlier CRA reports to NEMMCO

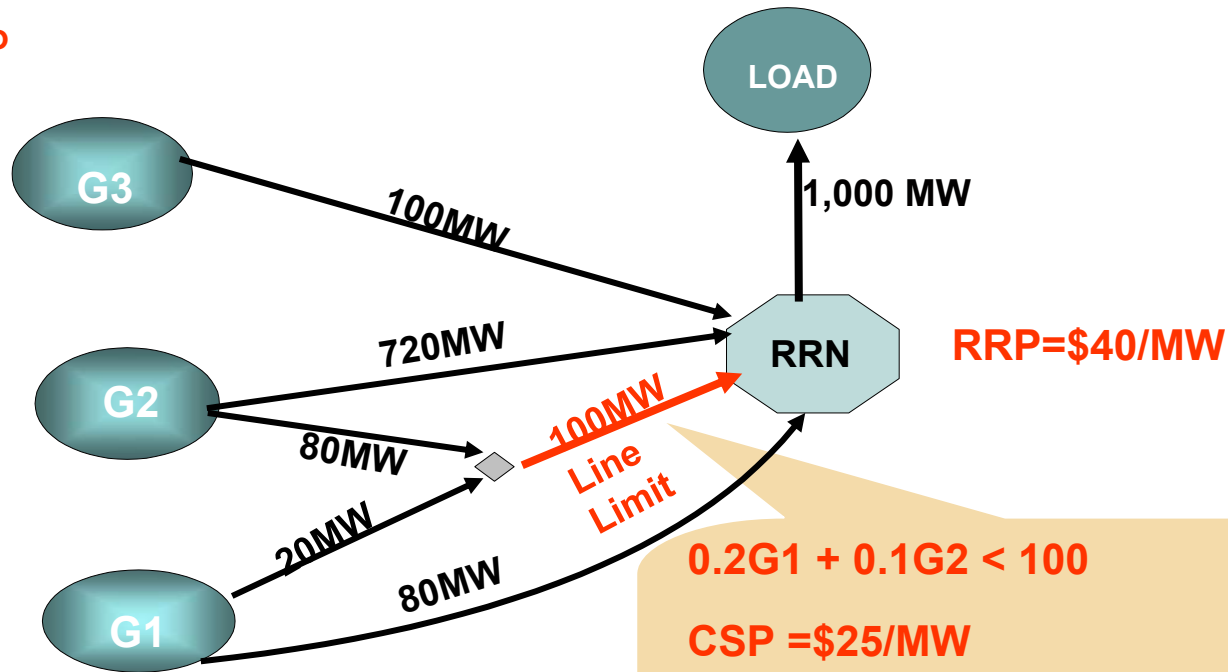
Scenario A dispatch situation

Offer PNP
\$/MW \$/MW

40 40

20 37.5

35 35



$$0.2G1 + 0.1G2 < 100$$

$$CSP = \$25/MW$$

(ie 10% of G2, and 20% of G1 goes via constraint and incurs penalty of \$25/MW)

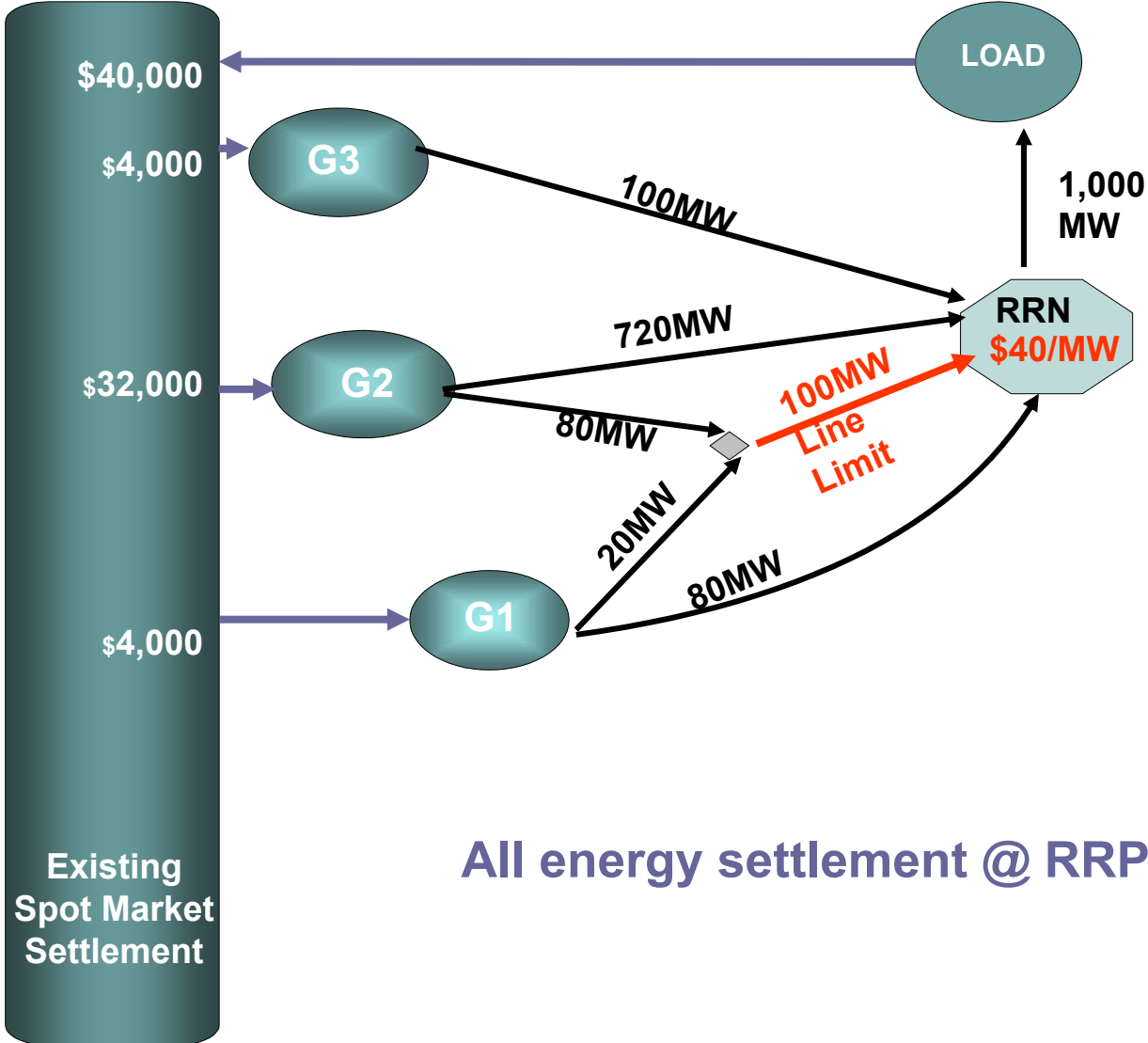
G3 marginal with offer price setting $PNP_3 = RRP = \$40/MW$

G1 also marginal with offer price = pseudo-nodal price $PNP_1 = \$35/MW$

$CSP = (RRP - PNP_1)/COEFF_1 = (40 - 35)/0.2 = \$25/MW$ of line flow

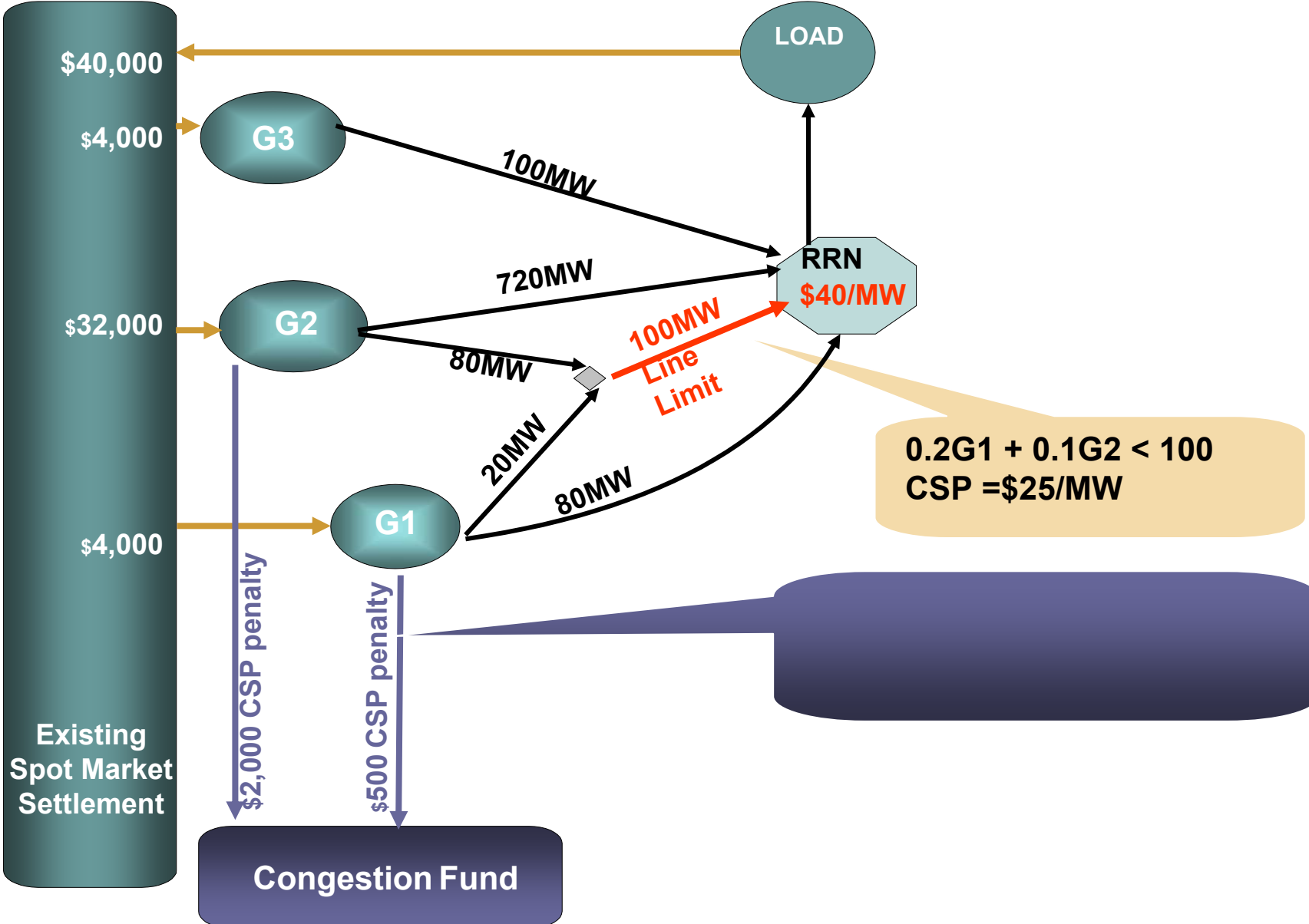
G2 fully loaded with $PNP_2 = RRP - CSP * COEFF_2 = 40 - 25 * .1 = \$37.5/MW$

A: Energy Market Settlement



All energy settlement @ RRP of \$40/MW

A: CSP flows



\$40,000

\$4,000

\$32,000

\$4,000

Existing
Spot Market
Settlement

A: CSP flows

LOAD

G3

100MW

G2

720MW

80MW

100MW
Line
Limit

G1

20MW

80MW

RRN

\$40/MW

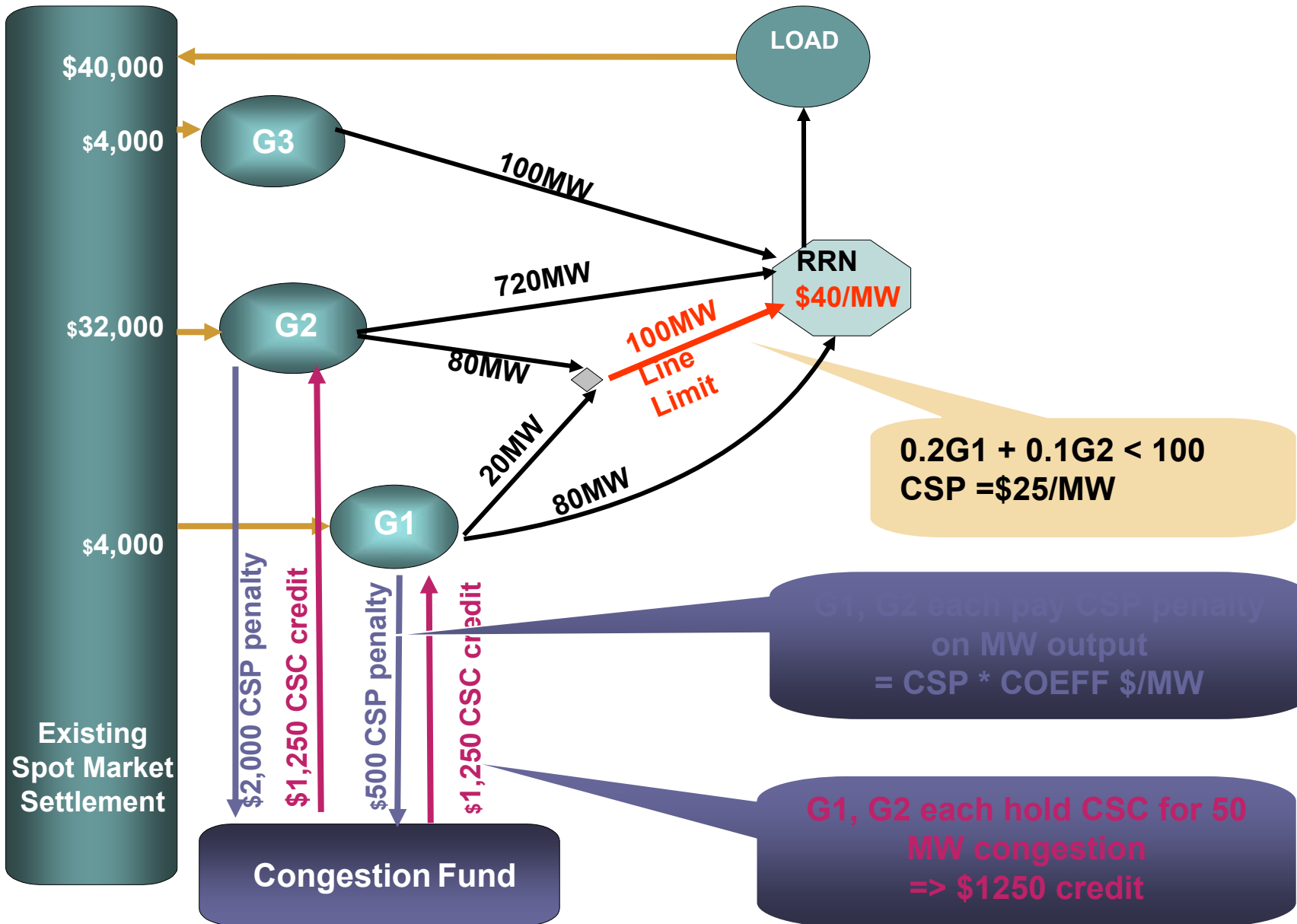
$0.2G1 + 0.1G2 < 100$
CSP = \$25/MW

\$2,000 CSP penalty

\$500 CSP penalty

Congestion Fund

A: CSP/CSC Settlement



B: Scenario A + supporting generation

Energy settlement as before, at RRP = \$40

But this means G3 offer must now be:

$$RRP - CSP * COEFF_3 \$52.50 = PNP_3$$

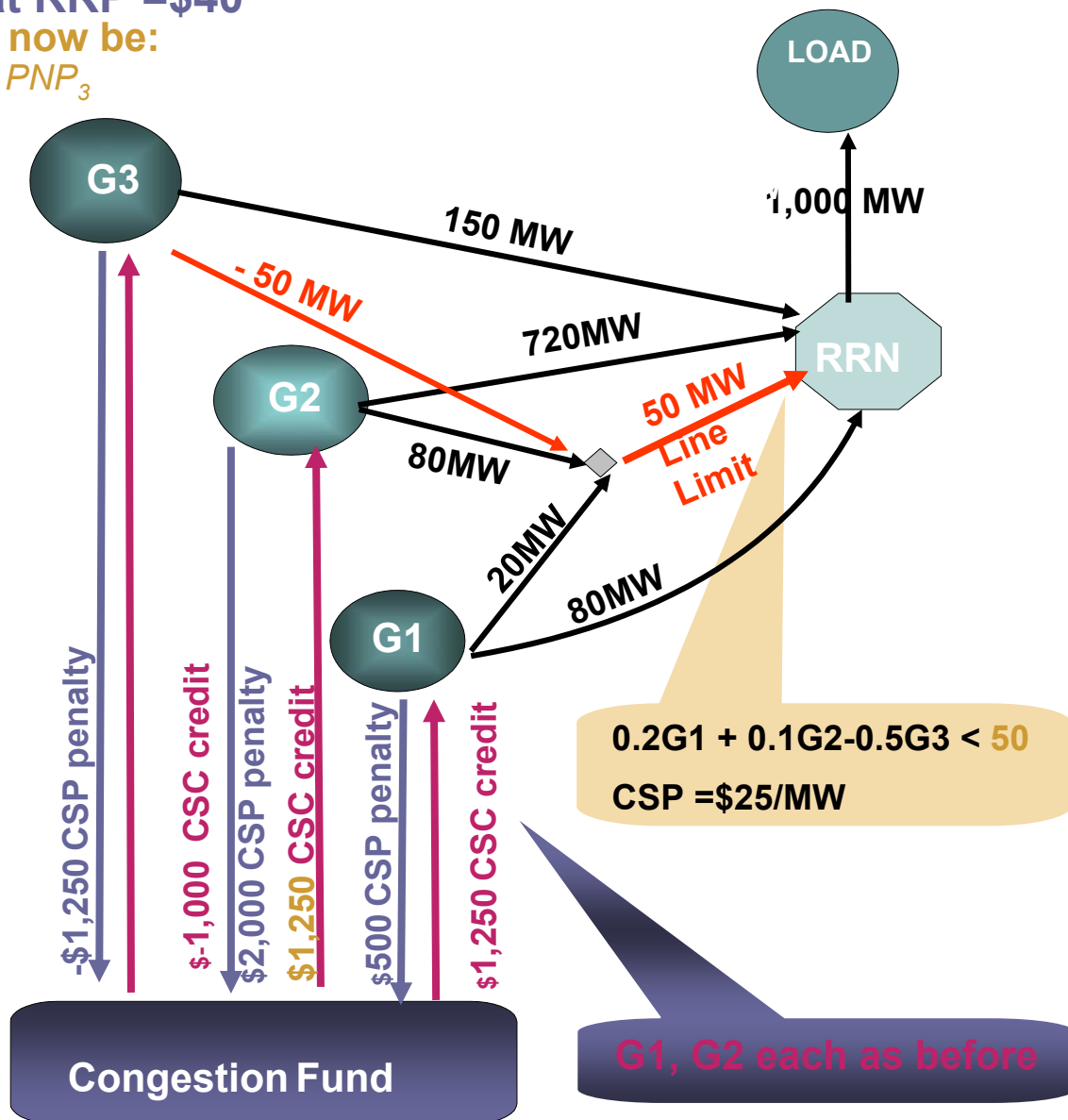
Unsupported line capacity now only 50MW

G1/G2 still have CSCs for 100 MW of "congestion"

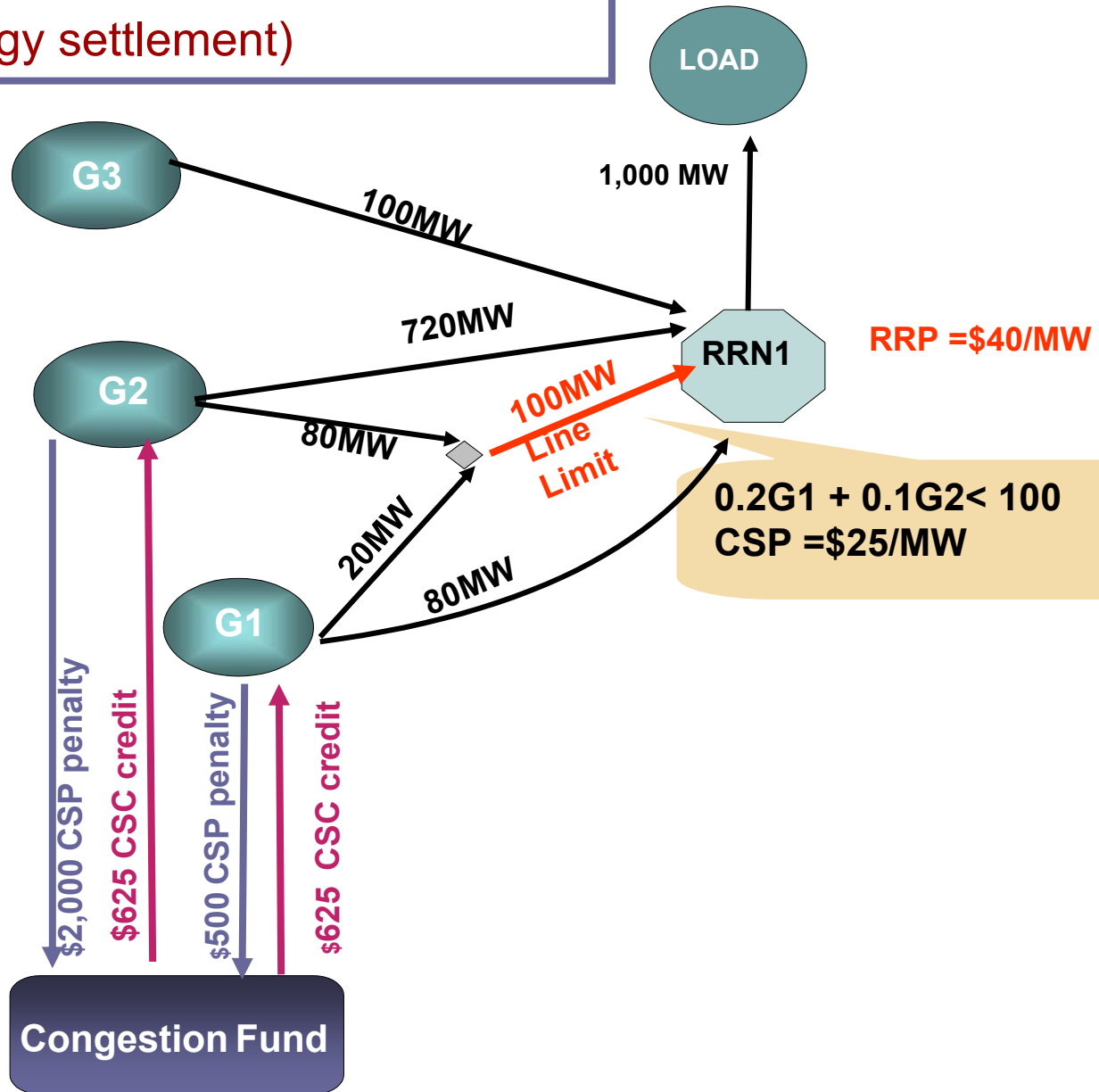
Supported by G3:

- generates 100MW
- creates 50MW "support"
- 40 MW fulfills CSC
- 10 MW paid for at CSP

(But G3 may also have been paid to accept CSC)



Back to Scenario A (ignoring energy settlement)



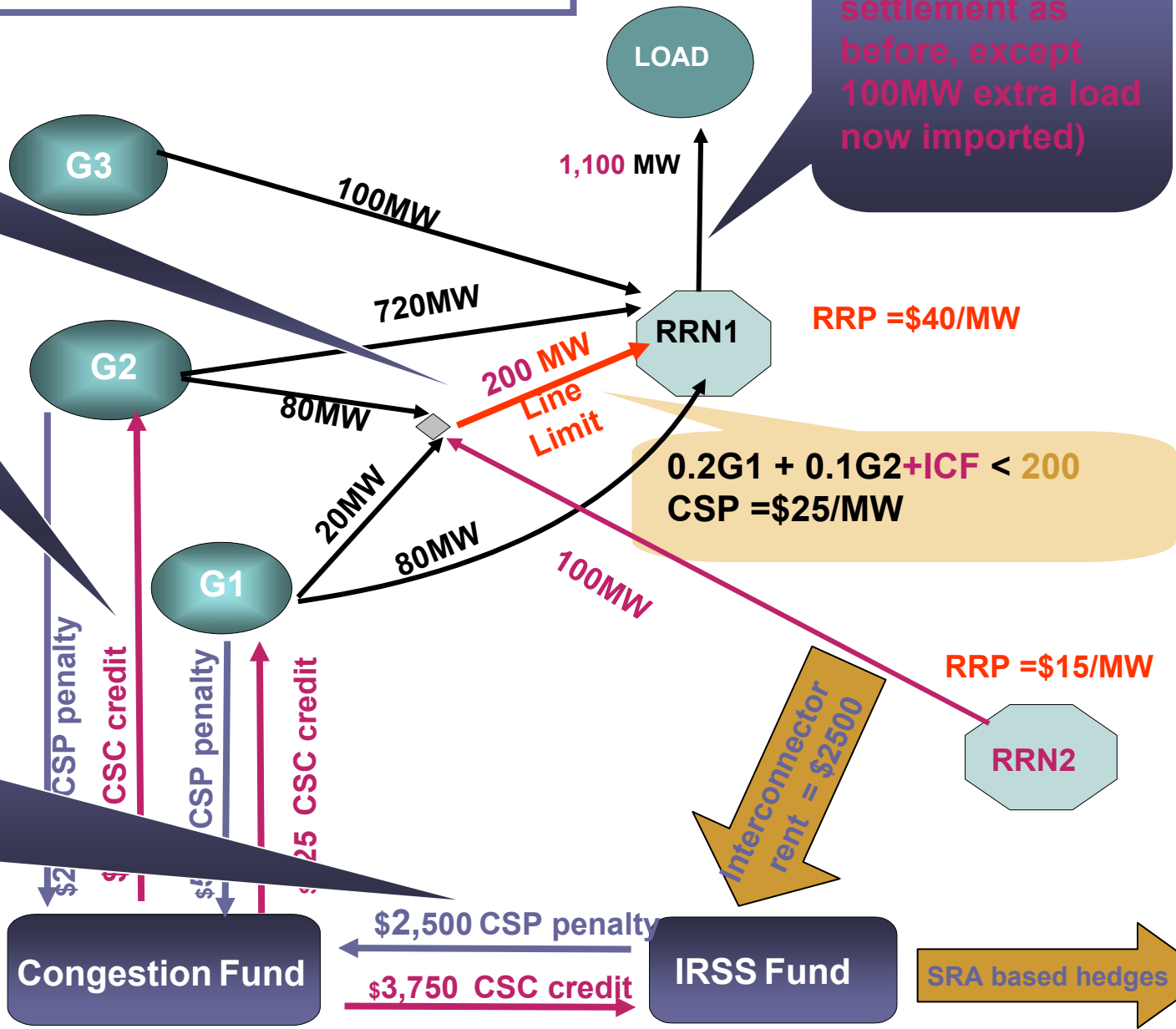
C: Scenario A + interconnector

Capacity now increased to 200MW

G1, G2 each hold CSC for only 25 MW congestion => \$625 credit

Interconnector pays CSP penalty, but holds CSC for 150MW congestion => \$3,750 credit

(Energy settlement as before, except 100MW extra load now imported)



CSP penalty

CSC credit

CSP penalty

CSC credit

\$2,500 CSP penalty

\$3,750 CSC credit

Alternative Interpretations

Different interpretations may suit particular situations

For example, G2 in A above may be thought of as:

- Selling $GEN = 800$ MW of energy at $RRP = \$40$
while “buying” $(GEN - CGEN) * COEFF = 30$ MW of “uncontracted congestion support” to support this sale at $CSP = \$25$
- Selling $GEN = 800$ MW at $RRP = \$40$
While paying a penalty of $CSP / COEFF = \$2.50 / MW$ for deviating from $CGEN$ by $(GEN - CGEN) = 300$ MW
- Selling $CGEN = 500$ MW at $RRP = \$40$
plus $(GEN - CGEN) = 300$ MW at its $PNP = \$37.50$

But the cashflows and incentives are really no different

And these “transactions” are all implicit in the (very simple) CSP/CSC mathematics

Participant Incentives

A CSP regime, on its own, provides “first order” incentives for constraint management, by

- Lowering the effective price (PNP) for “constrained off” generation
- Raising the effective price (PNP) for “constrained on” generation

But participants who can affect the CSP:

- Still have ‘second order’ incentives to generate somewhat less than the optimum when:
 - “constrained on” (to raise CSP, and CSP credits)
 - “constrained off” (to lower CSP, and CSP penalties)

CSCs alter this, creating second order incentives to generate the contracted quantity

*Incentives (detail)

The effective price signal for marginal production at p :

- Is a “Pseudo-Nodal Price” $PNP_p = RRP + CSP \times COEFF_p$
- Provides a “first order” correction for the local mis-signalling arising when constraints bind in a zonal market
- Would give a perfect signal with perfect competition at each node

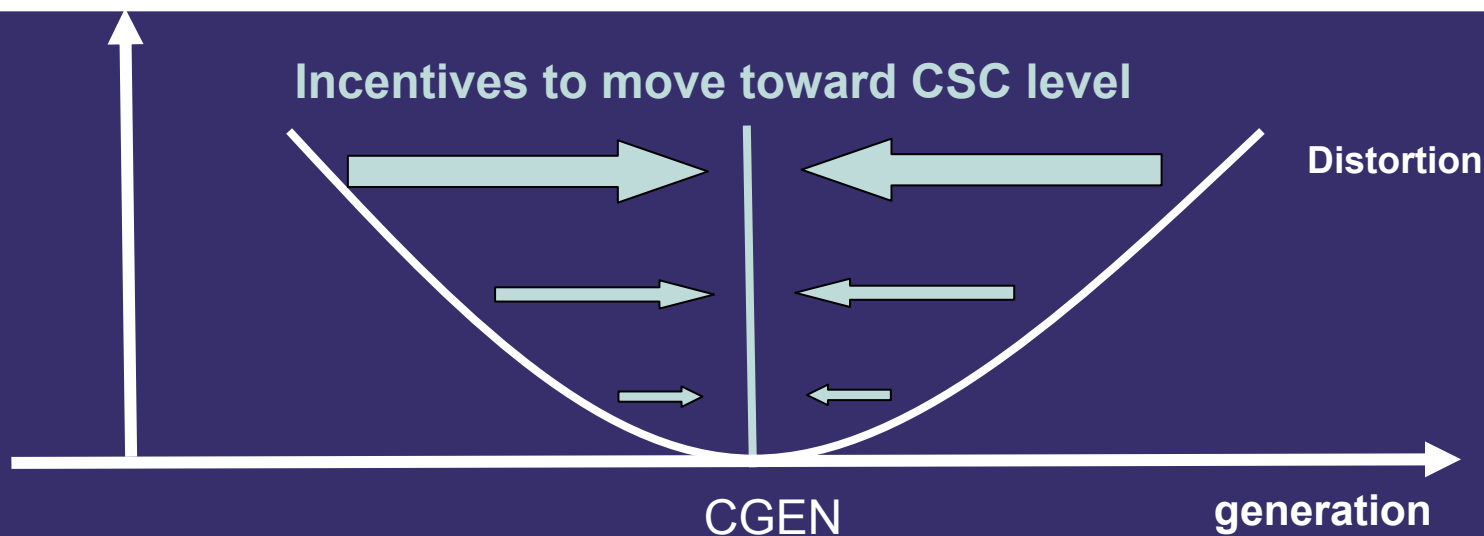
In reality the dispatch signal:

- Is perfect if the optimal perfectly competitive dispatch lies at/around the CGEN level, but otherwise
- “Second order effects” incentivise participants to move offers/dispatch toward the CGEN level (eg zero, with no CSC)

Thus CSCs provide a mechanism to:

- Incentivise desirable “constraint support” behaviour, and/or equivalently
- Mitigate localised market power

*Second Order Incentives



For example, in Scenario B above:

- G1 generates 100 MW @ $PNP = \$35/MW$ with CSC covering $CSCGEN = 500 MW$
⇒ 2nd order incentive to increase generation toward 500MW
- G2 generates 800 MW @ $PNP = \$37.5/MW$ with CSC covering $CSCGEN = 500 MW$
⇒ 2nd order incentive to decrease generation toward 500MW
- G3 generates 100 MW @ $PNP = \$52.50/MW$ with CSC covering $CSCGEN = 80 MW$
⇒ 2nd order incentive to decrease generation toward 80MW

Constraint Management

The CSP/CSC arrangement provides a mechanism to:

- Incentivise desirable “constraint support” behaviour
- Ration limited network capacity
- Provide for commercial compensation between affected parties
- Enhance effective/firm network capacity via a form of “network support contract”
- Provide dynamic control via differing CGEN levels when different constraints apply

These arrangements can readily be extended to cover:

- Non energy (“non-NEO”) implications of generation (eg reactive support)
- Ancillary services
- (And, potentially, TNSP performance)

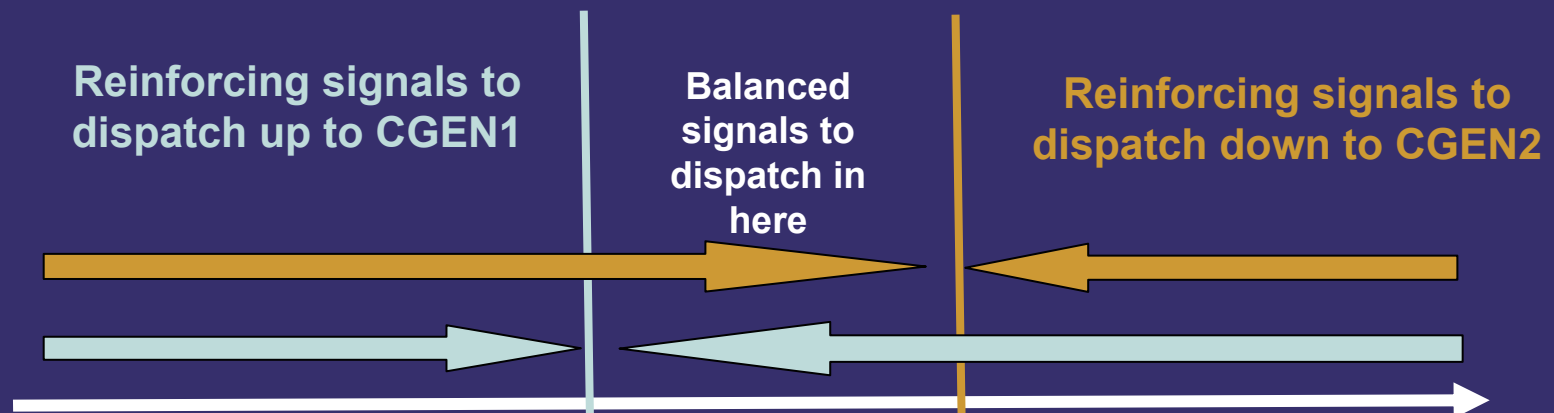
CSP/CSC is more versatile than LMP/FTR in this application

*CSCs vs FTRs for Constraint Management

FTRs apply only to generation/load, and effectively imply incentives to generate at the FTR level under all circumstances

But CSCs can also be applied:

- To interconnectors and ancillary services, and
- To incentivise different generation levels when different constraints bind (eg when congestion occurs in one direction or another)
- To give more precise control when multiple constraints bind, implying a conflict between 'ideal' dispatch levels



*Bundled CSCs

Bundled CSCs apply in the opposite situation, using a common CGEN when different constraints require similar responses

In Scenario A, suppose there were two constraints which could bind and effect G1, with prices as shown:

$$0.2G1 + 0.1G2 < 100 \quad \text{CSP1 (as in Scenario A)}$$

$$.1G1 + .3G2 < 100 \quad \text{CSP2}$$

Suppose G1 enters into a “bundled CSC” for CGEN = 250 MW

$$\begin{aligned} \text{Nett CSP penalty for G1} &= (GEN - CGEN) \times (\text{coeff1}_1 * \text{CSP1} + \text{coeff2}_1 * \text{CSP2}) \\ &= (GEN - 250) \times (.2\text{CSP1} - .1\text{CSP2}) \end{aligned}$$

- If only constraint 1 binds, the situation is identical to Scenario A
- But if constraint 2 also binds, G1 faces additional penalties for exceeding CGEN

NOTE: If a line can be congested in either direction, then each bound is a different constraint, requiring a very different response. Thus separate CSP/CSC arrangements should apply, and NOT a bundled CSC)

*Non-NEO Effects

Standard LMP/FTR theory deals with “Nodal Energy Only” (NEO) effects, treating generation as merely “negative load”

But “Non-NEO” effects, such as “reactive support” and “inertia” can easily be handled by the CSP/CSC approach:

- In fact, the mathematics does not distinguish NEO vs non-NEO effects
 - But the physical interpretation in terms of line flows may change
- For simplicity, consider the following (contrived) example:
 - G1 and G2 are actually located at the same node, so
 - 20% of the generation from both congests the line
 - But G2 provides some form of contingency response to halve the nett
 - So , really

$$COEFF_2 = 0.1 = NEOCOEFF_2 - NONNEOCOEFF_2 = 0.2 - 0.1$$

- Then all cashflows will be as above, with G1 and G2 facing different “pseudo-nodal prices”, but at the same node
 - Thus G2 only faces half the CSP penalty because of its contingency response

*Ancillary Services

Ancillary services create another class of “non-NEO” effects

Consider Scenario C, where line capacity increased to 200 MW:

- Suppose 50 MW of that increase comes from NCAS provided, say by interruptible load
- In principle, this can be represented as a “non-NEO” term in the constraint equation

$$0.2G1 + 0.1G2 + ICF < 150 + NCAS$$

- The NCAS provider creates capacity valued at $NCAS * CSP$
- A CSC could be established for a contracted amount, $NCASCON$
 - Implying a nett payment to the provider of $(NCAS - NCASCON * CSP)$
 - Leaving a firm rental pool corresponding to a capacity of $150 + NCASCON$

Access and Hedging

LMP (eg nodal) markets use FTRs to hedge locational price differences, thus providing “access” to distant locations

The NEM zonal market provides:

- Implicit, but non firm intra-regional access to the RRP
- Explicit, but non-firm inter-regional access via an SRA based “FTR”

With CSP/CSCs the NEM market design could provide:

- Explicit, and firm, intra-regional access to the RRP
- Explicit, and firm inter-regional access via an SRA based “FTR”
- With the proviso that the “firmness” of both arrangements depends on:
 - The firmness of underlying network availability, and
 - Including the critical constraints in the SP/CSC arrangements
 - The degree of participation by affected parties

*CSCs for “Access” Hedging wrt RRP

Of itself, a CSC provides hedging equivalent to an FTR, but:

- An FTR applies to all constraints which may bind, while a CSC applies only to a specific constraint (set)
- An FTR applies in an LMP market, but a CSC applies in a zonal market, only if a CSP applies to a specific constraint, thus:
 - Participants in an LMP market with no FTR receive a local price
 - Participants in a zonal market with no CSC, but affected by a CSP receive an equivalent PNP, but
 - Participants in a zonal market with no CSC or CSP receive the RRP
- Thus introducing a CSP/CSC arrangement :
 - Replaces the “price only hedging” implicit in a zonal market,
 - With an explicit quantity/price hedge
 - (and may make it feasible to negotiate TNSP guarantees)

*CSC Support and Inter-Regional Hedging

Constraint rents support CSCs, as for FTRs:

- With no CSCs, the rental pool will be $CSP * RHS$
 - Eg, $RHS = \text{“unsupported line capacity”}$
- This pool defines nett support for CSCs and/or FTRs
 - Eg, for an interconnector with no CSCs this rent is just the IRSS
- **CSCs with generators / NCAS providers firm and expand this pool, irrespective of dispatch**
- **CSCs with interconnectors firm and share the pool arising from trans-regional constraints, irrespective of dispatch**
- **The result is a fully firm support for inter-regional hedging, but only:**
 - With respect to this particular constraint, and
 - To the extent that the RHS is firm and/or
 - A performance guarantee can be obtained from the relevant TNSP

*Implications of Non-Participation

Each non-participant in a CSP regime:

- Will act in response to RRP, rather than PNP
- Is thus not incentivised to “support” the constraint
- Affects the rents available to support CSCs with other participants, and
- Creates risk for those parties and/or the rental pool

For example, if G3 opted out under Scenario B:

- They would have no incentive to generate to relieve congestion, thus:
 - Reducing nett capacity available to other generators
 - Making it more difficult and expensive to supply load
- If other participants still hold the same CSCs
 - There will be a deficit in the constraint rental pool
 - That deficit will fluctuate, depending on the behaviour of G3

Participants in a CSP regime who hold no CSCs may face dispatch signals which are imperfect (as for LMP, but generally better than the status quo)

*Implications of Load Variation

One obvious class of “non-participant” is the load

- (This is irrelevant in the above examples, because all load is at the RRN, with no “local load” affecting constraint congestion)

In general, though, we must ask how firm hedging can be provided, when:

- Local load is varying, and (in principle)
- This implies variations on the constraint “RHS”, and hence
- This implies variations in “effective transfer capability”

In reality the RHS may be set for critical conditions, and not varied

- All that matters here are the likely load levels when constraints bind, because $CSP = 0$ otherwise

But, if the RHS does vary, as it will implicitly in a nodal NEMDE:

- The desirable CGEN levels will vary accordingly, and this may be worth accounting for in “constraint management” contracts
(similarly for variations due to maintenance outages etc)
- The implicit hedging provided will obviously vary accordingly
- In fact these constraint variations may be seen as different constraints, with differing CCON/CGEN levels, effectively providing “conditional hedging”
- Participants would need to manage their energy market exposures accordingly

*Analysis of Hedging Adequacy

First, note that all discussions of hedging relate to “NEO” effects only

- Non-Neo / ancillary service “network support” arrangements may need nett funding, and create/ control risks unrelated to energy trading

Second, a full analysis would consider the network of intra-regional and inter-regional energy contracting, which we have ignored

Third, consideration must be given to the implicit hedging a zonal market already provides for:

- Loads (effectively price and volume)
- Generation (effectively only price)

Thus (eg) the choice of RRP has off-setting implications for both sides of the market. Analysis must focus on:

- The nett impact (eg in terms of intra-regional settlement surplus), and
- The incremental impact of , eg, CSP/CSC arrangements

And we must ask what RRN/RRP “intra-regional hedging access” is actually being granted to

*Access to a “Reference Node”

Analytically, any node can be taken as a RRN, and the marginal cost of supplying that node as the RRP. This price could be derived from:

- A nodal model, or
- A zonal model with constraints oriented toward that RRN

This RRP would then apply to all generation and load, but CSP penalties derived using the coefficients from correctly oriented constraints:

- Will produce the same PNPs for each participant, Irrespective of the RRN, and
- This would apply also to weighted averages corresponding to a “hub” RRN

Now, if a CSC is issued to a generator corresponding only to “network capacity”, with no allowance for “local load”:

- The generator will pay a CSP penalty on its whole generation, but only get a CSC credit on the “transferred” amount
- Thus what it generates to meet local load is effectively sold at the local PNP
- But local load is paying RRP, thus effectively folding a “reverse” CSC to access that price
- So there will be net rent remaining in the CSP/CSC pool which could support an additional “forward” CSC covering generation for local load
- Such CSCs can certainly be issued, but CGEN will then vary as local load varies
(For example we could have $CGEN = \text{constant} + \text{a proportion of local load}$)

The situation is different, though, if a “hub” price sets the RRP

*Access to a “Hub” Price

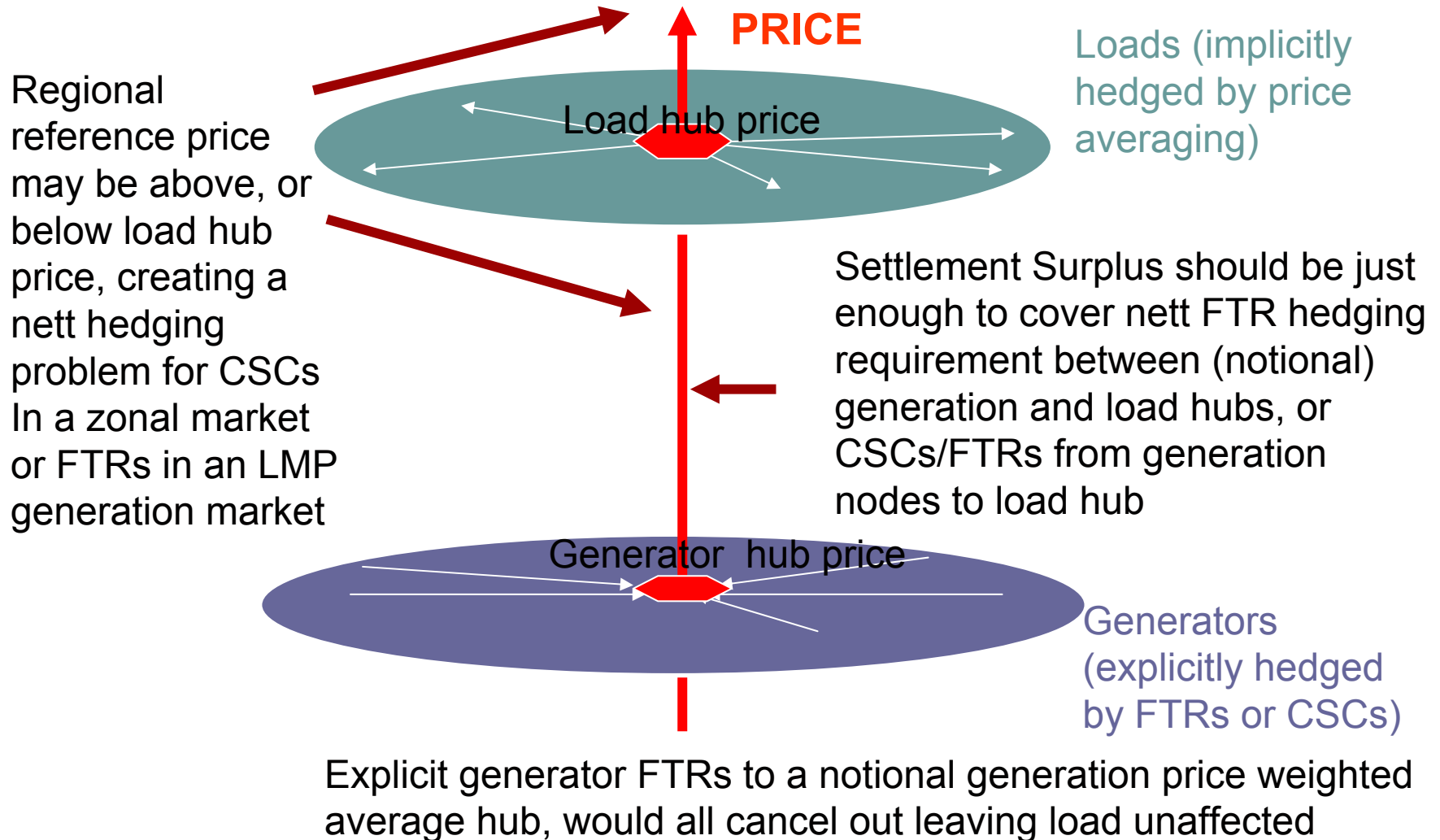
In a nodal market :

- We could form load/generator “hub” prices as load/generation weighted averages
- The difference between these corresponds to an “intra-regional settlement surplus”
- It would be available to support FTRs giving generators access to the “load hub” in a market where generators faced nodal prices, but load prices were averaged
- But a nett hedging problem arises if the load price is set to some other (eg RRN) level

Essentially the same situation arises in a zonal market:

- If a comprehensive CSP regime effectively prices all generation at “nodal prices” (PNPs)
- Then the rents collected as CSP penalties should support CSCs to the load hub
(Note that, with weighted average load pricing the “reverse CSCs” implicitly assigned to “local loads” are implicitly adjusted so that they all cancel out)
- But the “location” of that hub shifts, implying changing coefficients in constraints “oriented” to it
- Fortunately, constraint orientation makes no difference to:
 - The (RHS) “capacity” of the constraint available for allocation (via CCON), or
 - The CSP price on the constraint, or
 - The individual PNPs for each participant
- But, because the coefficients are implicitly varying, the implied CGENs will be adjusted for load conditions
- This is equivalent to the load adjustment discussed previously for a RRN based market

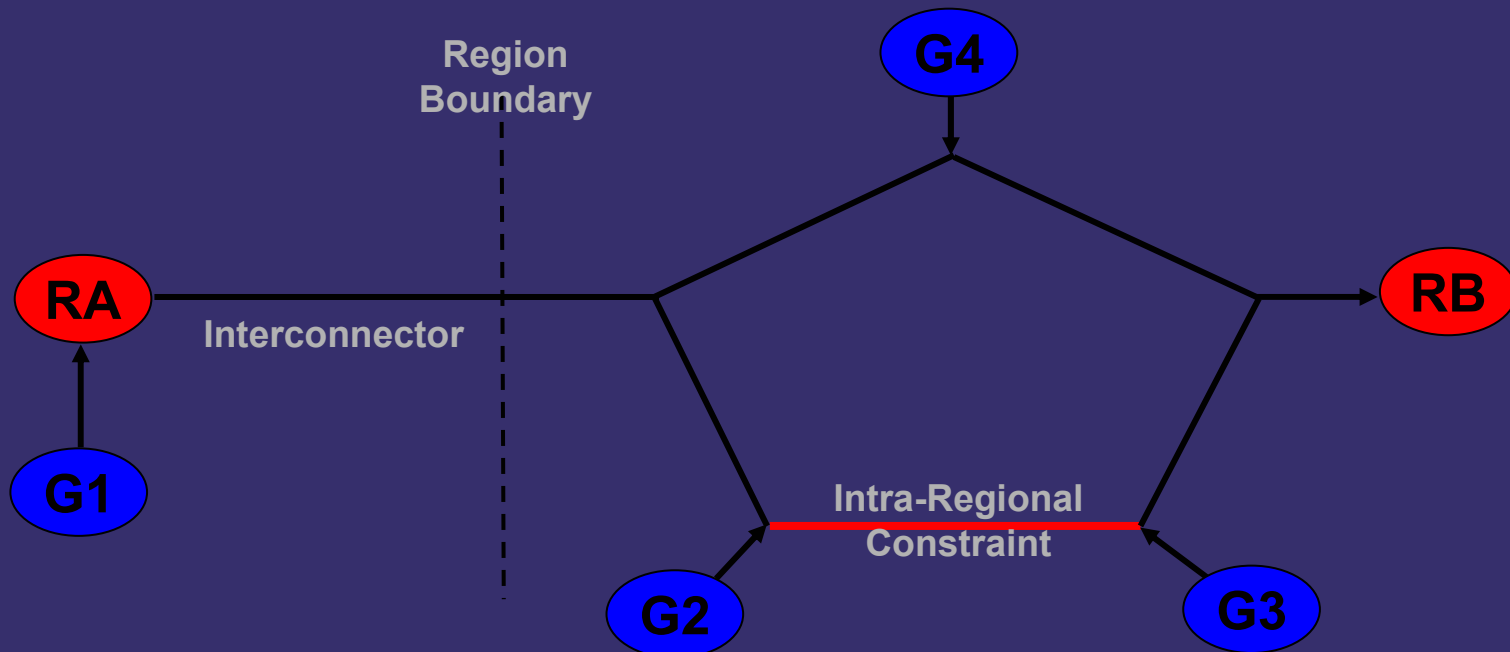
*Hedging Between Generator and Load Prices



Further Examples: “Gatekeeper” Situations

NEMMCO “Gatekeeper” report/presentation (reference [3])

- Very detailed illustration of CSP/CSC for “interconnector support”
- Includes treatment of electrical flows and price derivations and an LP based “market-clearing” spreadsheet
- Discusses looped and unlooped variants on the following network



Further Examples: Interconnector Interactions

NEMMCO “Interactions” report (reference [4])

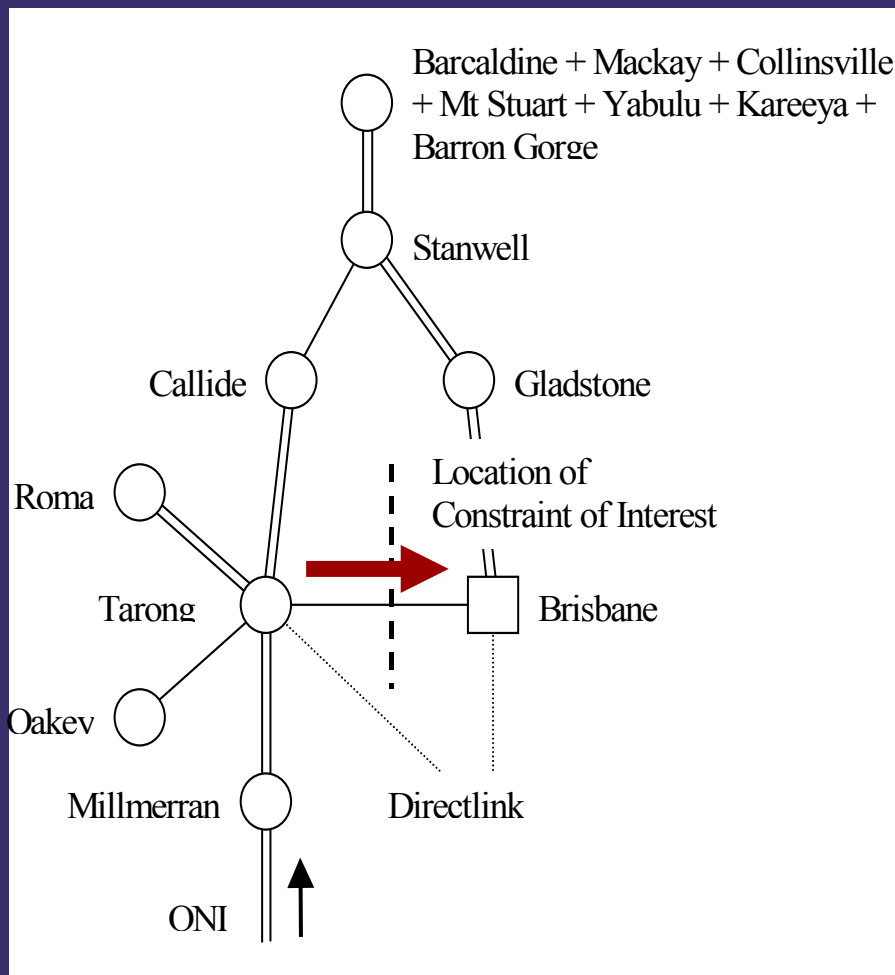
- Illustrates CSP/CSC for three real trans-regional constraints, with cross border loops, MNSPs and other interconnector interactions

Appendix D of the Theory Report extends this:

- As for Scenario C all interconnectors pay CSP penalties, as determined by constraint coefficients, to common rental pool
- Rental pool may be firmed by CSP/CSC arrangements with generators and NCAS providers
- Payments are made from that pool to each IRSS pool in accordance with CSCs held by interconnectors
- These supplement any IRSS rents due to other constraints
- Thus (provided network capacity is available) firm inter-regional hedging can be provided on each interconnector:
 - irrespective of actual interconnector flows (or actual generation/NCAS provision)

Tarong Example (simplified)

$$0.5(\text{Tar} + \text{Mil} + \text{Cal} + \text{Sta} + (\text{NQLD}) + \text{Oak} + \text{Glad} + \text{QNI}) + 0.6\text{Rom} + 0.1\text{DI} \leq 3250$$



NSW/QLD differential = \$12.50
CSP = \$25

NOTIONALLY:

Dlink collects \$12.50 in rent but pays \$2.50 CSP penalty on 10% flow over constraint

QLD generation pays \$12.50 CSP penalty on 50% flow over constraint

QNI, collects \$12.50 in rent but also pays \$12.50 CSP penalty

Optimal dispatch indifferent between NSW and QLD generation

- Back off QLD generation and/or
- Back off/reverse QNI

*Tarong: CSP/CSC Implications

With no CSP/CSC arrangement:

- The dispatch described above is optimal
- The economic trade-offs occur in the NEMDE
- The market signals are quite different, and create conflict
- Eg QLD generators get RRP, with no CSP penalty
- NSW generators effectively do face penalty, because it is implicit in inter-regional price differential

With a CSP/CSC arrangement:

- **All affected parties pay CSP penalties into a common pool**
 - Ie around \$12.50 per MW transfer/generation, or \$2.50 for Dlink
- **This creates a pool of $CSP * RHS = 25 * 3250 = \$81,250$**
- **This is then distributed in accordance with the CSCs**

Tarong Example: Energy Settlement

(NSW price = \$10.00, QLD price = \$22.50)

	Output/ Transfer (MW)	Energy “Sales” (\$)
QNI	-200	-2500
Qgen	6680	150300
Dlink	100	1250
TOT	6580	149050
Qload	6580	148050*

**Energy market is settled at RRP,
as at present**

**QNI gets negative rent from
counter-price flow**

* \$1000 difference in “energy sales” arises because NSW pays \$1000 for 100MW nett transfer from QLD at NSW RRP = \$10.00

Tarong Example: CSP Settlement

(CSP = \$25, NSW price = \$10.00, QLD price = \$22.50)

	Output/ Transfer (MW)	Energy “Sales” (\$)	Implied Flow (MW)	CSP Penalty (\$)
QNI	-200	-2500	-100	-2500
Qgen	6680	150300	3340	83500
Dlink	100	1250	10	250
TOT	6580	149050	3250	81250
Qload	6580	148050*	-	-

CSP penalties in proportion to implied flows on congested line

QNI gets negative “penalty” because its reverse flow actually relieves congestion

CSP penalty = CSP * Implied flow = 25 * implied flow

Implied flow = MWGEN * COEFF

(or MWTRAN * COEFF)

Tarong Example: CSP/CSC Settlement

(Assuming prior allocation of CSCs as specified)

	Output/ Transfer (MW)	Energy Sales (\$)	Implied Flow (MW)	CSP Penalty (\$)	CSC (CCON) (MW)	CSC Credit (\$)	Nett CSP/CSC (\$)	Final Position (\$)
QNI	-200	-2500	-100	-2500	1000	25000	27500	25000
Qgen	6680	150300	3340	83500	2250	56250	-27250	123050
Dlink	100	1250	10	250	0	0	-250	1000
TOT	6580	149050	3250	81250	3250	81250	0	149050
Qload	6580	148050	-	-	-	-	-	148050

$$\text{CSC Credit} = \text{CSP} * \text{CCON} = 25 * \text{CCON}$$

QNI can support 2000MW of hedges at QLD-NSW price difference of \$12.50

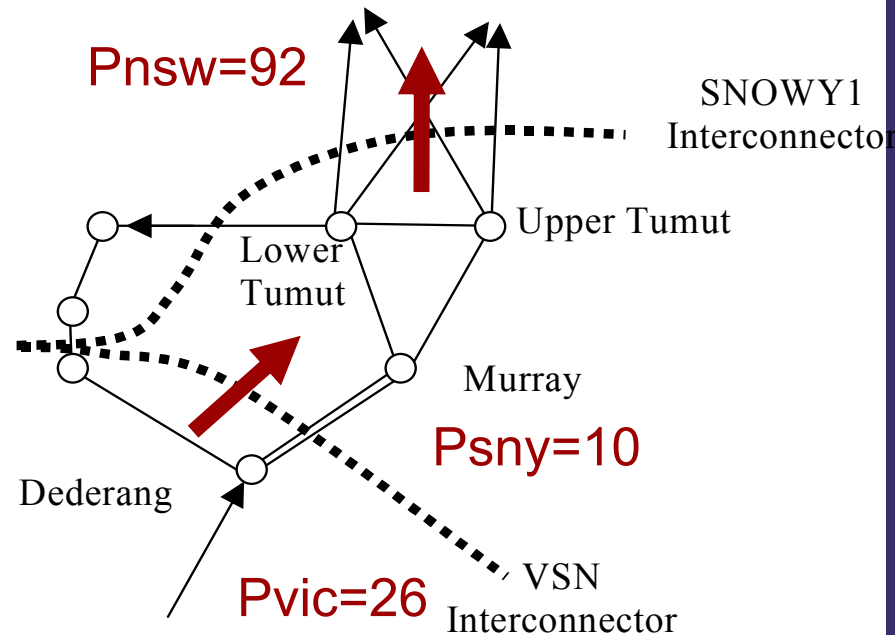
Dlink gets \$10 per unit transfer (and would be marginal if offering at \$10)

QLD generation gets:

\$101250 for 4500MW (ie 2250 MW congestion) at QLD RRP = \$22.50
 + \$21800 for 2180 MW at its PNP, which equals the NSW RRP = \$10.00

*Snowy (simplified)

0.8 (SNY1- NLT) - 0.2VSN - .9NUT <= 1183



Price patterns may be odd, with possible counter-price flow (eg pattern shown with CSP=100)

CSP “corrects” this so that:

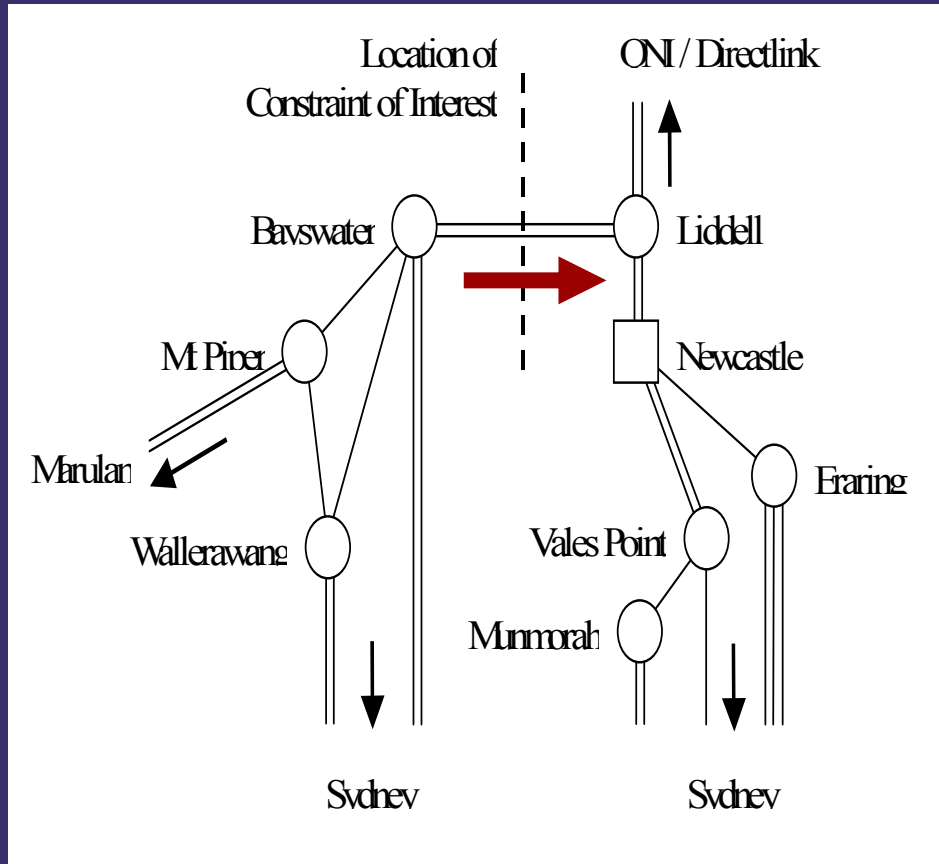
- NUT/NLT effectively face NSW price
- SNY1 effectively faces VIC price
- VSN gets compensated for counter-price flow (nett hedge value = zero)
- A rental pool is created

Implicitly, this gives priority access to NUT/NLT (reflecting their network position)

- But CSCs can re-allocate those rents to support firm hedges into NSW from VIC./SNY1

*Northern NSW (simplified)

$$0.7 (QNI + DL - Lid) + 0.3Bay + 0.1(Er34 + Pip + Wal) - 0.2(Er12 + Val + Mun) \leq 1020$$



Congestion is decreased by:

- Generation in NE NSW
=> CSP reward

Congestion is increased by:

- Northward flow on Dlink/QNI
- Generation in NW NSW
=> CSP penalty

This implies a NSW-QLD price differential, which is:

- Collected by QNI/Dlink, but
- Partially refunded because their offtake point is (70%) on the QLD side of the constraint

Again CSCs re-allocate rents to match agreed transfer rights, irrespective of flows

Allocation Issues: CSCs vs FTRs

If an LMP market FTRs are used to provide both “intra-regional” and “inter-regional” access

Allocation of FTRs would be an issue if:

- A design were adopted in which generators faced some form of LMP (nodal or sub-regional) within each load region
- FTRs were to be used to protect participant positions when boundaries changed

In the modified zonal market design envisaged here:

- Intra-regional access for loads is still provided by a common price
- Inter-regional access is still provided by SRA based “FTRs”
- But Intra-regional access for generation is provided by CSCs

We will thus focus on the “allocation” of CSCs

Financial Support for CSCs

Introduction of a CSP/CSC arrangement must be analysed with respect to the status quo:

- Parties advantaged by the CSP will typically have that advantage reduced by a CSC
- Parties disadvantaged by the CSP will typically have that disadvantage reduced by a CSC

To the extent that CSCs merely “ration” existing capacity, they are self-funding, in the sense that:

- The rent required to meet CSC obligations
- Is generated by the CSP penalties

Where CSCs are used to enhance effective network capacity:

- External funding will be required
- As for any other investment in network capacity

Arranging CSCs

CSP/CSC arrangements may deliver significant value to the market as a whole, but are not costless:

- They imply some participants foregoing opportunities to respond freely to, or affect, either zonal or nodal market prices
- Such arrangements must either be:
 - Agreed as part of an overall market reform package, or
 - Individually negotiated into place

Obvious policy issues arise with respect to:

- The agency responsible
- The rules and criteria employed
- The source of any external funding

Arrangements may differ, eg for intra-regional vs inter-regional situations

CSC Allocation Policy

There are significant policy issues involved because:

- CSC/FTR rights have significant value to participants, and
- “Rights” required for policy purposes may actually have negative value
- Agencies may have inconsistent mandates

“Allocation” of (particularly, negative valued) rights could be:

- Compulsory as part of a transition regime
- Negotiated as part of a “constraint support” (eg NCAS) deal
- A condition of involvement in a particular CSP regime yielding positive nett benefit
- Determined by market wide formula, expressed in terms of, eg
 - Installed capacity, or
 - Historic generation
(which provides a sustainable basis, so long as the network remains)

CSC Allocation Options

Short term trading (or auctions) can not

- Define long term property rights
- Provide long term protection of participant positions
- Induce participants to voluntarily accept (nett) obligations

Thus some long term allocation mechanism is necessary:

- To ensure constraint support
- To support/incentivise generation investment

In particular allocation based on current/future behaviour risks compromising economic signals for operation and investment

- If it is known that “inappropriate” behaviour will secure future rights that behaviour is incentivised
- **In the limit, even the status quo “allocates rights”.. in each trading interval!**

Conclusion

The CSP/CSC concept is novel, but does have advantages in that:

- It can be selectively applied to particular participants (eg generators only), constraints, and affected nodes,
- It can thus provide a commercial mechanism to incentivise specific “constraint support” performance for both participants and transmission providers
- It can be readily generalised to deal with non-energy effects
- It thus provides a consistent framework for energy and “network support” ancillary services

Thus the CSP/CSC concept could:

- Allow evolutionary development of a consistent zonal market
- While providing dispatch/pricing efficiencies with respect to key constraints

Way Forward?

The CSP/CSC approach:

- Creates new tools to implement policy, and
- Broadens the range of (theoretically consistent) options available, but
- Does not, of itself, determine or resolve policy issues

If accepted, conceptually, evolutionary development would require:

- Verification of theory?
- Broader industry understanding
- Practical trial?
- Establishment of responsibilities
- Determination of criteria for application to specific constraints
- Establishment of processes (eg for allocation/negotiation)
- Integration with investment/boundary review processes

The aim is to provide a coherent market-wide framework, selectively applied to relatively few constraints

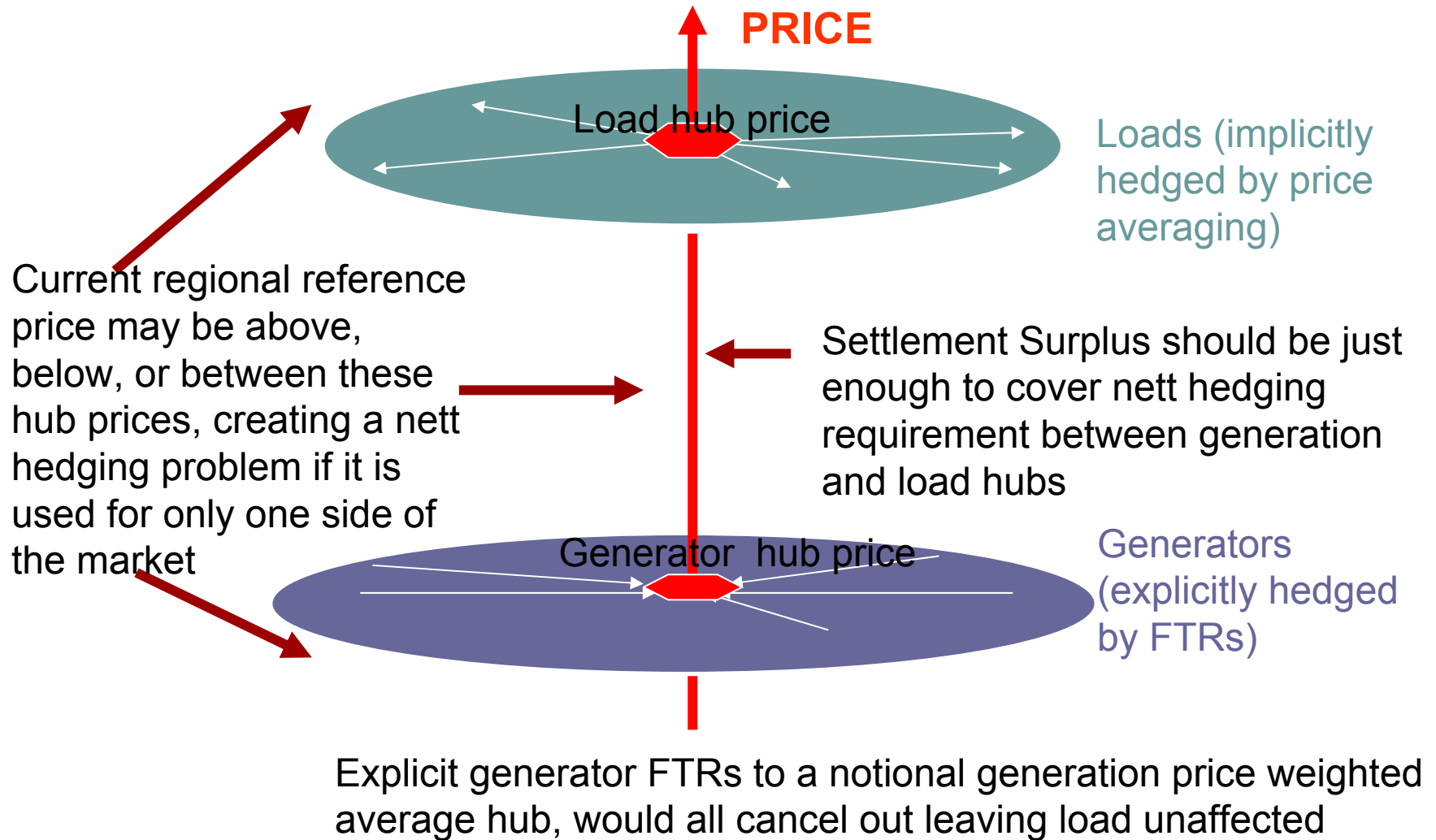
*Postscript: FTR Allocation Issues

Although less relevant to the final recommended design, the Theory paper discusses FTR allocation issues in some detail:

The key points are:

- Nett FTR allocation is limited to network capacity
- Load price averaging implicitly assigns balanced allocation of positive/negative valued rights to load
 - If generation is paid the same RRP, there is no extra rent to support intra-regional CSC/FTRs
 - If generators faced lower prices, on average, rents would be generated to support FTRs for nett flows
 - FTRs to support current generation patterns would require a balanced allocation of positive/negative valued rights to generation within a region

*FTR Hedging Where Generator and Load prices Differ



*FTR Allocation when Boundaries Change

Suppose a new region has lower prices, on average, then:

- Generation will resist, and seek FTRs retaining access to old RRN
- Loads will not!

The actual IRSS available to support FTRs will match the nett cross-boundary flow... (ie local generation – local load)

- Allocation of (positive valued) FTRs providing existing generation volumes access to the old RRN, would have to be offset by
- Allocation of (negative valued) FTRs providing existing load volumes access to the old RRN

This should be sustainable, so long as loads keep growing, but raises obvious policy issues

- (Although note that grand-fathered allocation does NOT distort locational investment signals)

Summary

Summary (1)

Within NEM regulatory framework for network investment, retain regional concept

Broaden criteria for regions in conjunction with targeted and flexible contract based pricing and incentives to manage inter and intra regional congestion

Regions to be

- Mechanism for pricing material and persistent congestion
- Forward looking
- Longer review period
- Longer notice period

Summary (2)

Constraints representation based on Direct Physical Representation

Inappropriate bidding mitigated by short term flow limits but preferably by robust bidding incentives used to price congestion (CSP/CSC)

Congestion contract allocation to suit role – regulatory function

- Simple congestion rationing – e.g. grant to incumbent but impacts new entrant
- Inappropriate bidding (market power)
- Network efficiency - negotiation

Questions