Centre for Energy and
Environmental Markets

CEEM Specialised Training Program
EI Restructuring in Australia

Network services and the NEM

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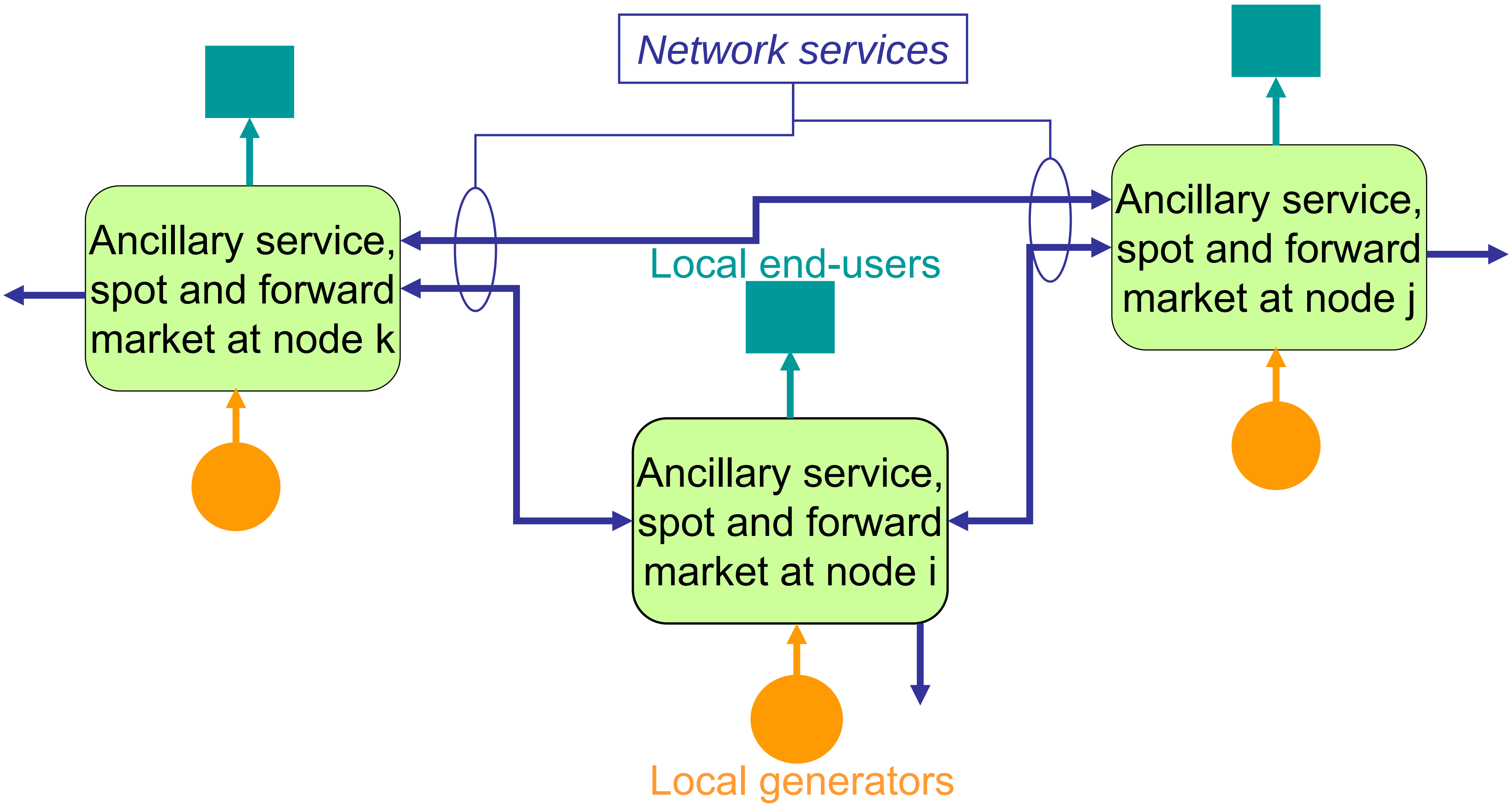
Outline

- Ideal - nodal market at each connection point:
  - Ancillary services, spot energy, future risk
  - Network arbitrage versus local resources
  - Active demand-side participation
- Impractical near term, uncertain long term:
  - Complexity, market power, uncertainty
- Practical approaches depend on context:
  - Regional markets & negotiation frameworks
  - Network service, pricing & investment protocols:
    - To allow distributed resources to compete

Ideal: competitive EI modeled by nodal markets

- Based on a market at each node:
  - Local generators & end-users
  - Flows to & from the network
  - Nodal ancillary service, spot & forward markets
  - Nodal spot prices set by simultaneous auction
- Network flows determined to maximise the benefits of trade (network-based arbitrage):
  - To exploit diversity in resource availability
  - Subject to network losses & flow constraints

Network arbitrage between nodal markets



Much of the value of network services derives from ancillary service & investment timescales

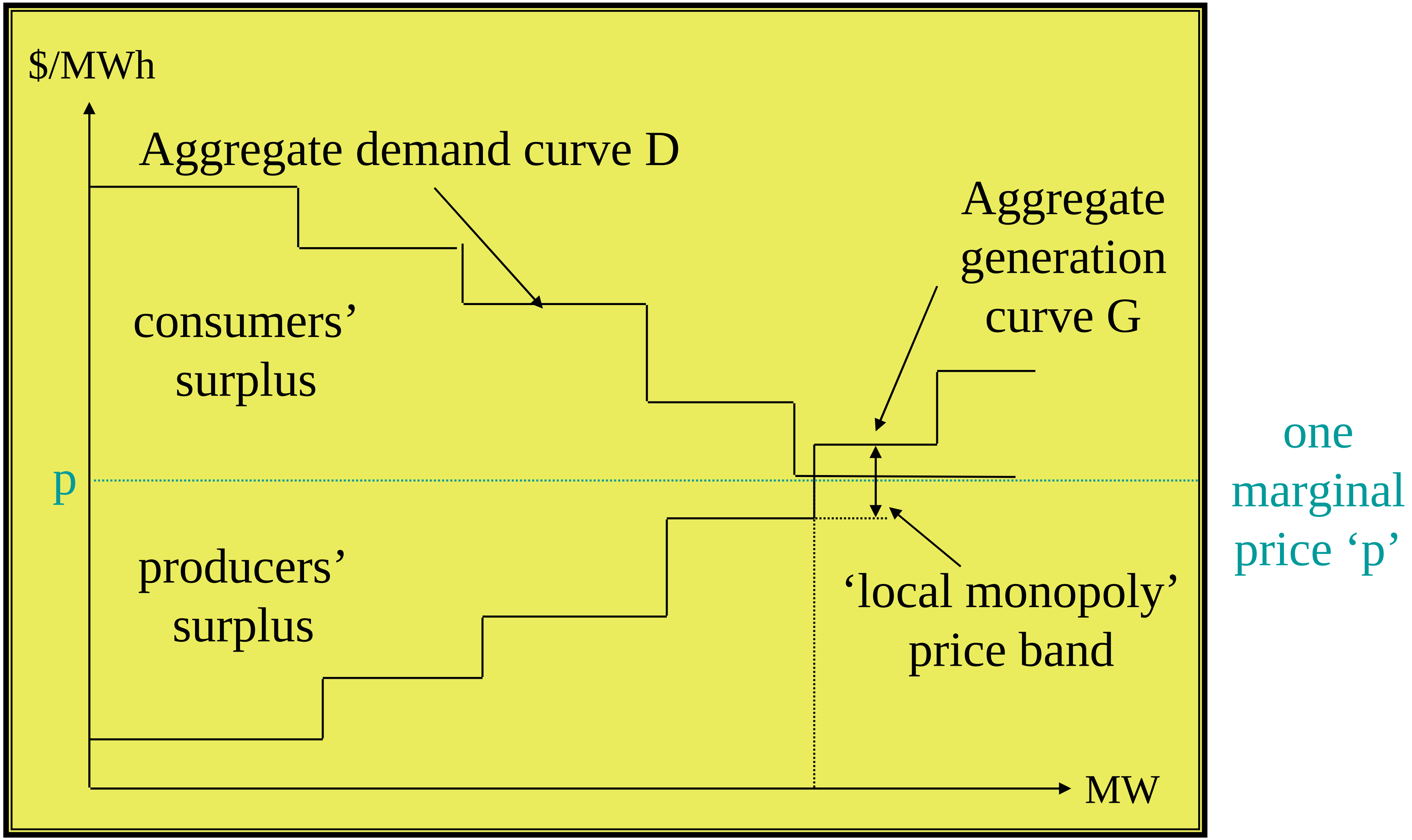
A definition of network services in an ideal competitive electricity industry

- Arbitrage between nodal markets
  - in ancillary services, spot energy & future risk
- Subject to:
  - Availability of network elements
  - Energy losses in network components
  - Maximum ratings of network elements
  - Operating limits imposed for system security:
    - Influenced by the characteristics of generators, loads & network elements as well as the system operating state
    - Matters of judgement rather than objectively set

Solving nodal spot markets that include a network model

- Single node assumption (or strong network):
  - All sellers & buyers at one location
- Two node model:
  - Sellers at one node, buyers at the other:
    - Constrained line but no losses
    - Unconstrained line with line losses
    - Competing options to relieve a network flow constraint
- Three and five node models:
  - Interaction between lines in a meshed network

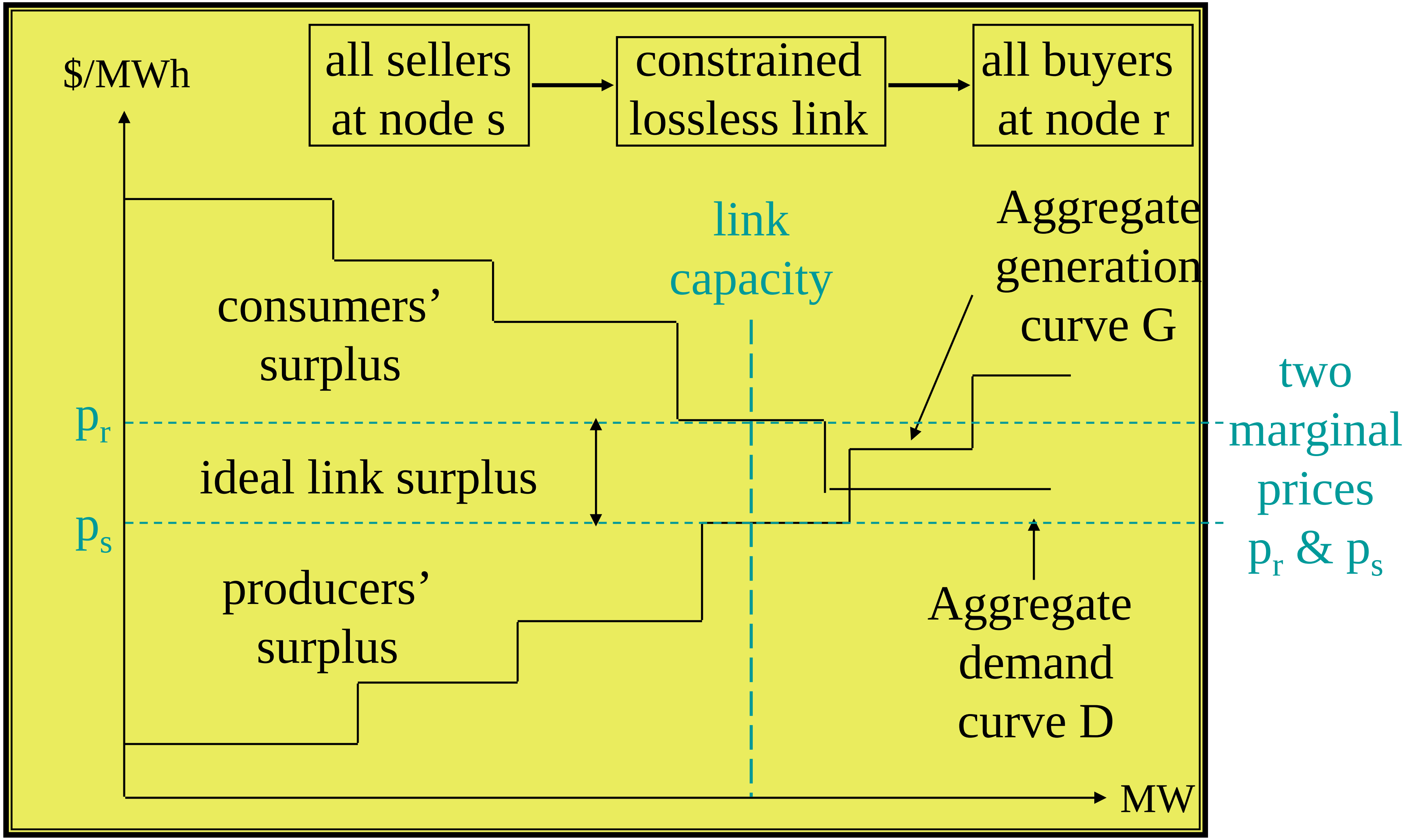
Single node spot market



Issues illustrated by one node example
(all participants at one location or strong network)

- Buyers & sellers see the same nodal price
- No revenue to network operator:
  - No network-based arbitrage
- The marginal buyer or seller may have a 'local monopoly':
  - The ability to set price within a limited band
  - More likely with fewer participants

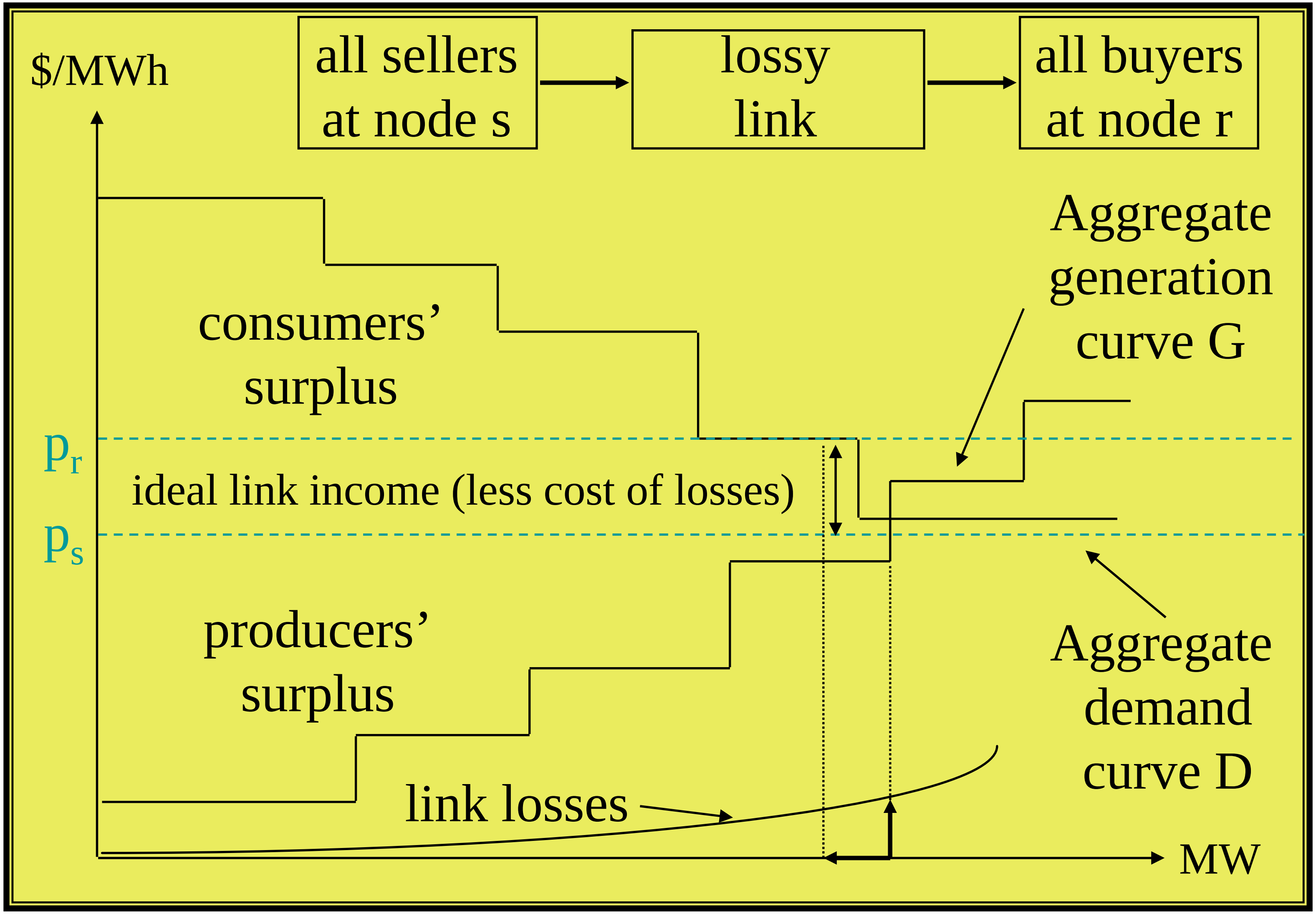
Two-node spot market with constrained lossless link



Issues illustrated by 2 node example: constrained, lossless link

- Nodal prices are set to constrain flow to link capacity (quantity rationing):
  - $p_r > p_s$ (always true for radial case)
  - link outage causes market collapse
- Link owner has a perverse incentive:
  - to constrain link capacity (but not to zero)
- Sellers & buyers may capture some of ideal link surplus due to ‘local monopoly’:
  - Local market power greater if link constrained

Two-node spot market with unconstrained lossy link



related nodal prices p_r & p_s

Issues illustrated by 2 node example: unconstrained, lossy link

- Unconstrained, lossy link between all sellers & all buyers
- Link operator buys at sending end, sells at receiving end, increasing link flow until:
  - cost of next increment of flow = its sale value:

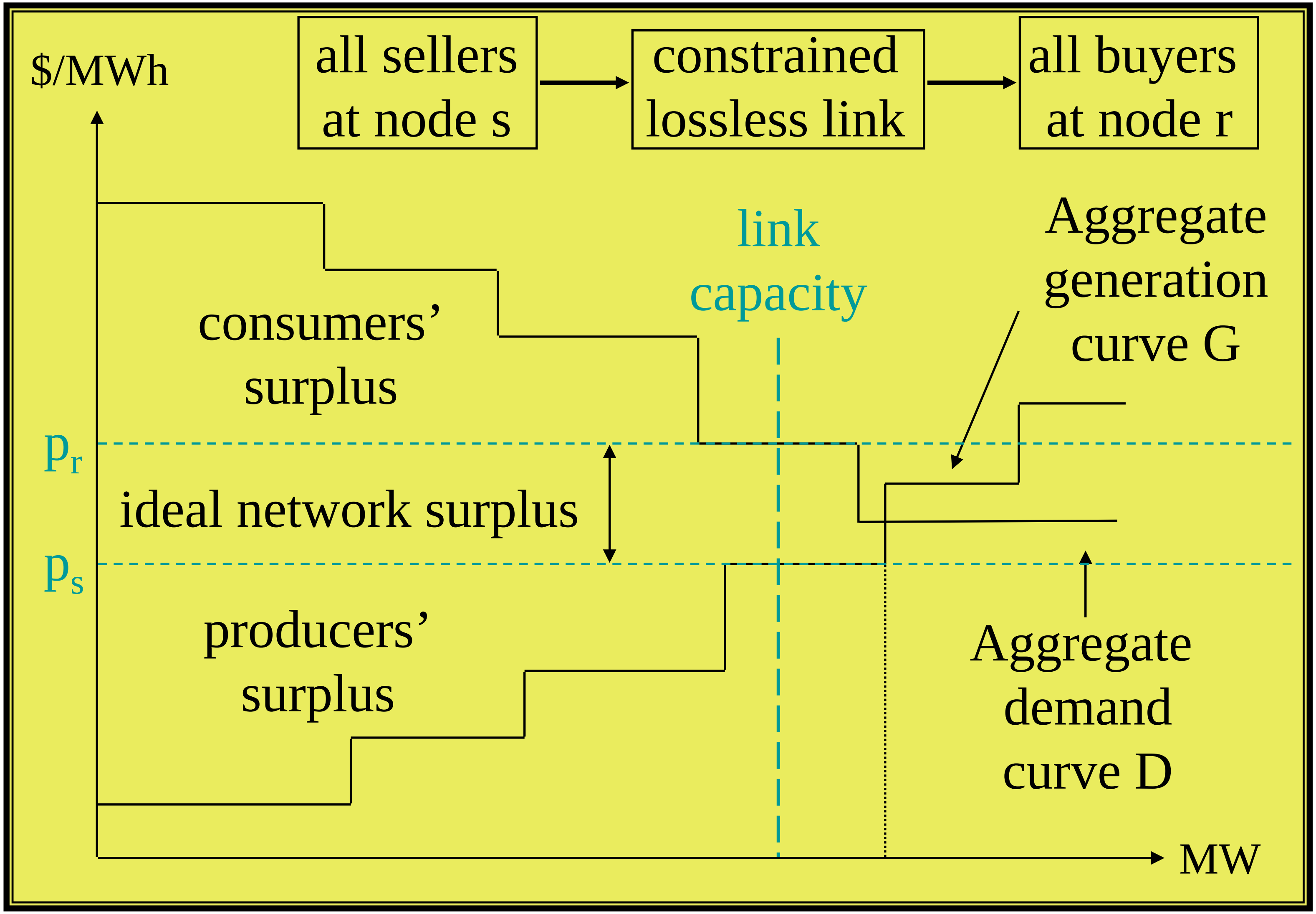
    i.e. $p_s(\Delta X+\Delta L) = p_r \Delta X$ [ΔX = sale, ΔL = loss]

    hence: $p_r = (1+ \Delta L/ \Delta X)\, p_s$
- Thus nodal prices are related by the incremental loss of an unconstrained link

Relieving network flow constraints

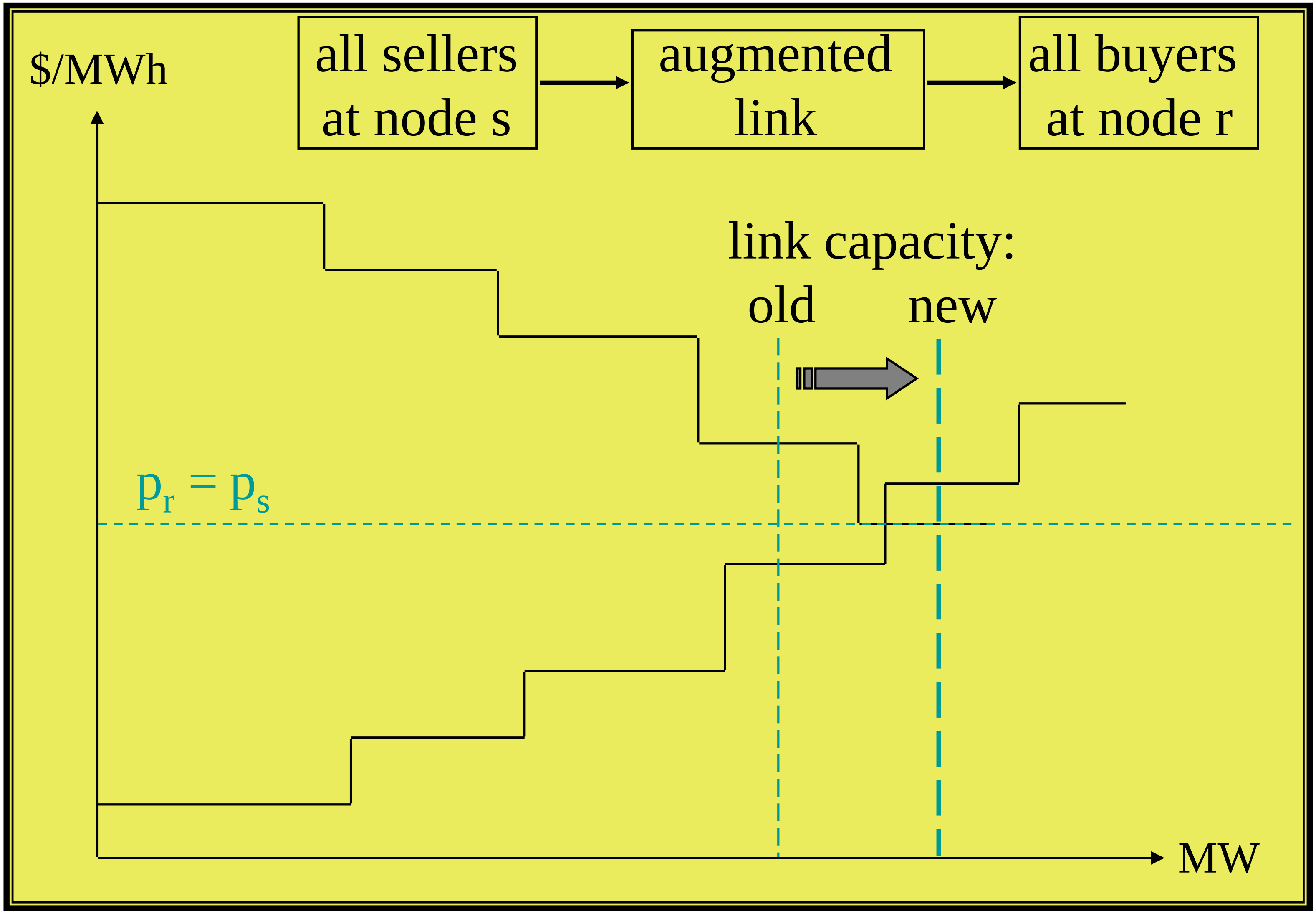
- Link flow constraints can be alleviated by:
  - investment in additional link capacity
  - investment in distributed resources:
    - Appropriately located generation, storage or load
  - relaxation of QOS criteria
- Investment underwritten by forward markets:
  - generator: sell CFD or call option at node ‘r’
  - load: buy CFD or CO at node ‘s’
  - link: buy CFD/CO at node ‘s’ and sell CFD/CO at node ‘r’

Relieving network flow constraints:
Situation prior to resolution of constraint



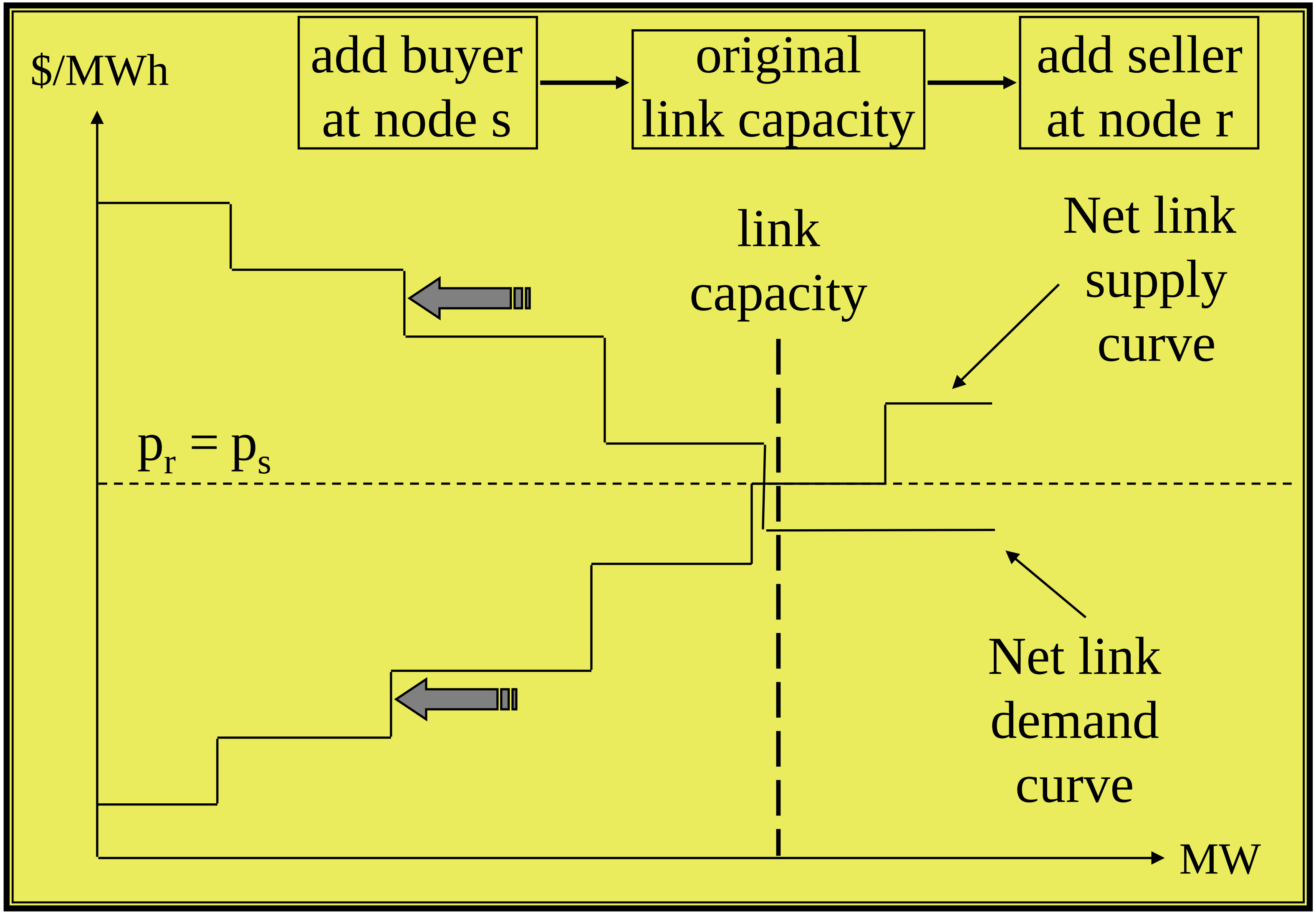
two marginal prices p_r & p_s some network surplus

Relieving network flow constraints:
Option 1 - augment link capacity



one marginal price $p_r = p_s$, no network surplus

Relieving network flow constraints:
Option 2 - add distributed resources



one marginal price $p_r = p_s$, no network surplus

Relieving network flow constraints: Selecting the best option

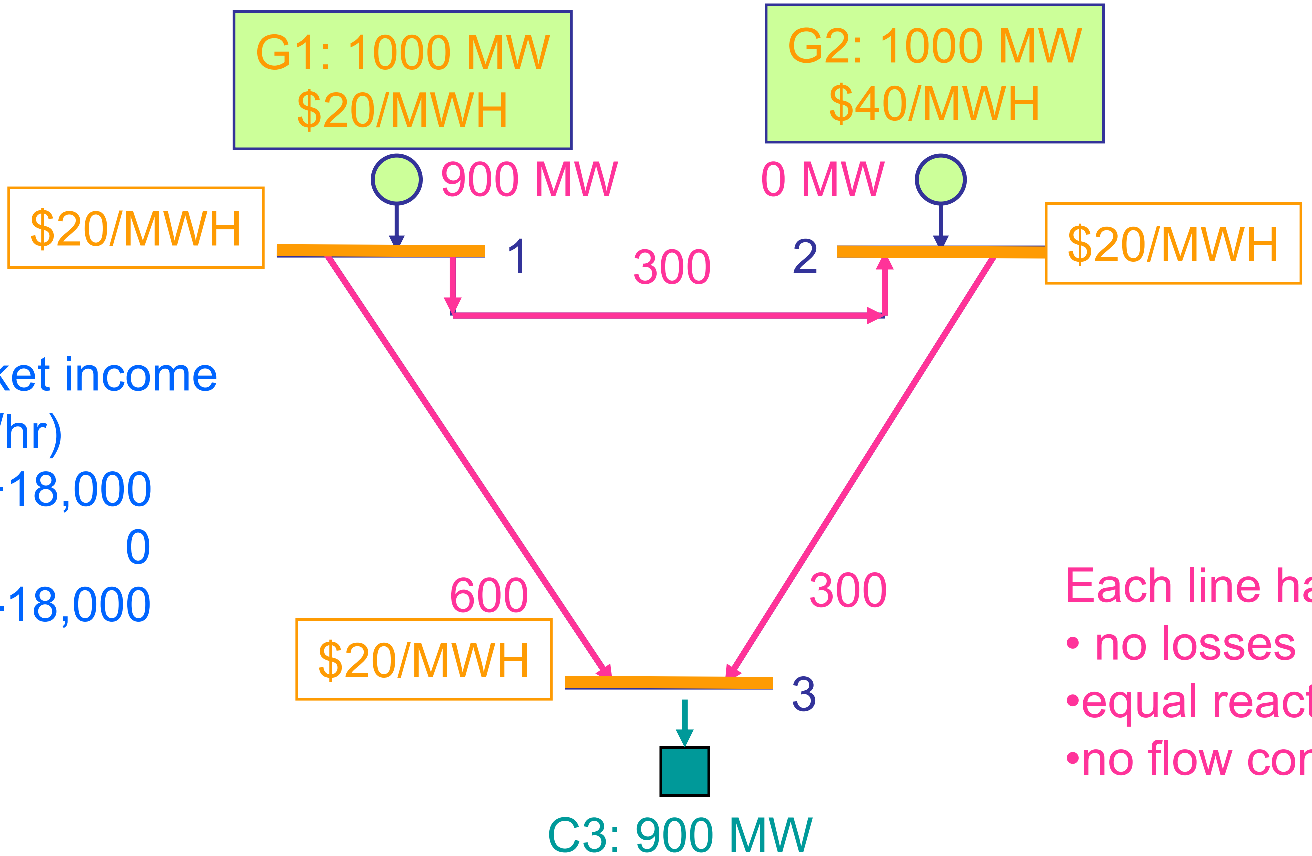
- Traditional approach:
  - NSP augments link, recovers cost from users
- Ideal competitive industry approach:
  - Link and distributed resource options compete:
    - Return on investment not guaranteed by regulator
    - Whichever investment option first achieves a bankable project (eg adequate contract cover) will proceed
    - Spot price difference falls if link capacity augmented:
      - unless link capacity can be controlled & bid into the market
- Without liquid AS, spot & forward markets:
  - Regulator could facilitate a negotiated outcome

Meshed networks

- A meshed network contains at least one loop:
  - At least two network elements operate in parallel
- Flows in parallel network elements are inversely proportional to element impedances
  - Voltage drops across parallel elements are equal
- Impedance = reactance if no network losses:
  - Element resistances are then all zero
- Flow constraints can propagate through the network

Nodal spot markets: 3-node meshed network

No network flow constraints or losses



Spot market income ($/hr)

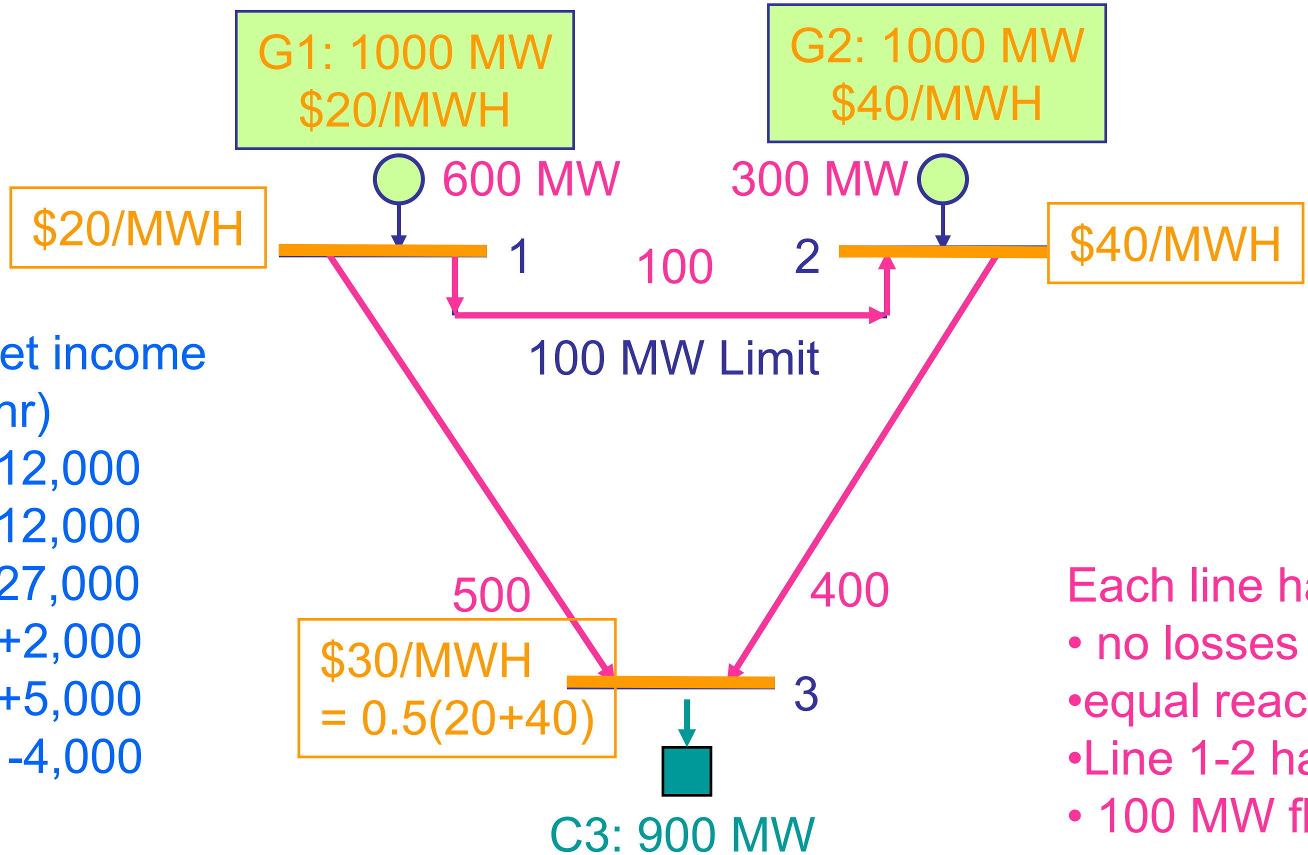
- G1: +18,000
- G2: 0
- C3: -18,000

Each line has:

- no losses
- equal reactance
- no flow constraints

Nodal spot markets: 3-node meshed network

One constrained link



Spot market income ($/hr)

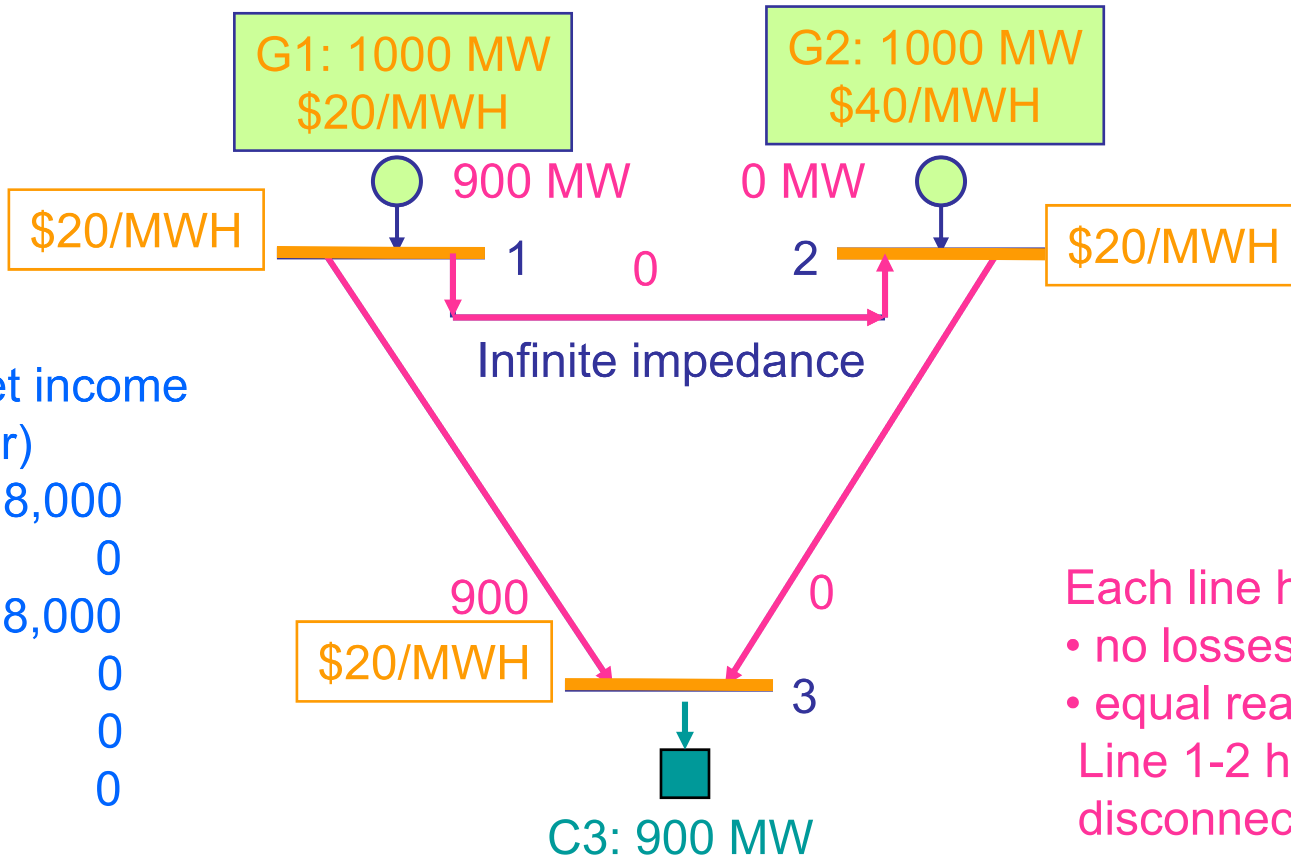
- G1: +12,000
- G2: +12,000
- C3: -27,000
- L12: +2,000
- L13: +5,000
- L23: -4,000

Each line has:

- no losses
- equal reactance
- Line 1-2 has:
- 100 MW flow limit

Nodal spot markets: 3-node meshed network

Constrained link disconnected



Spot market income ($/hr)

- G1: +18,000
- G2: 0
- C3: -18,000
- L12: 0
- L13: 0
- L23: 0

Each line has:

- no losses
- equal reactance

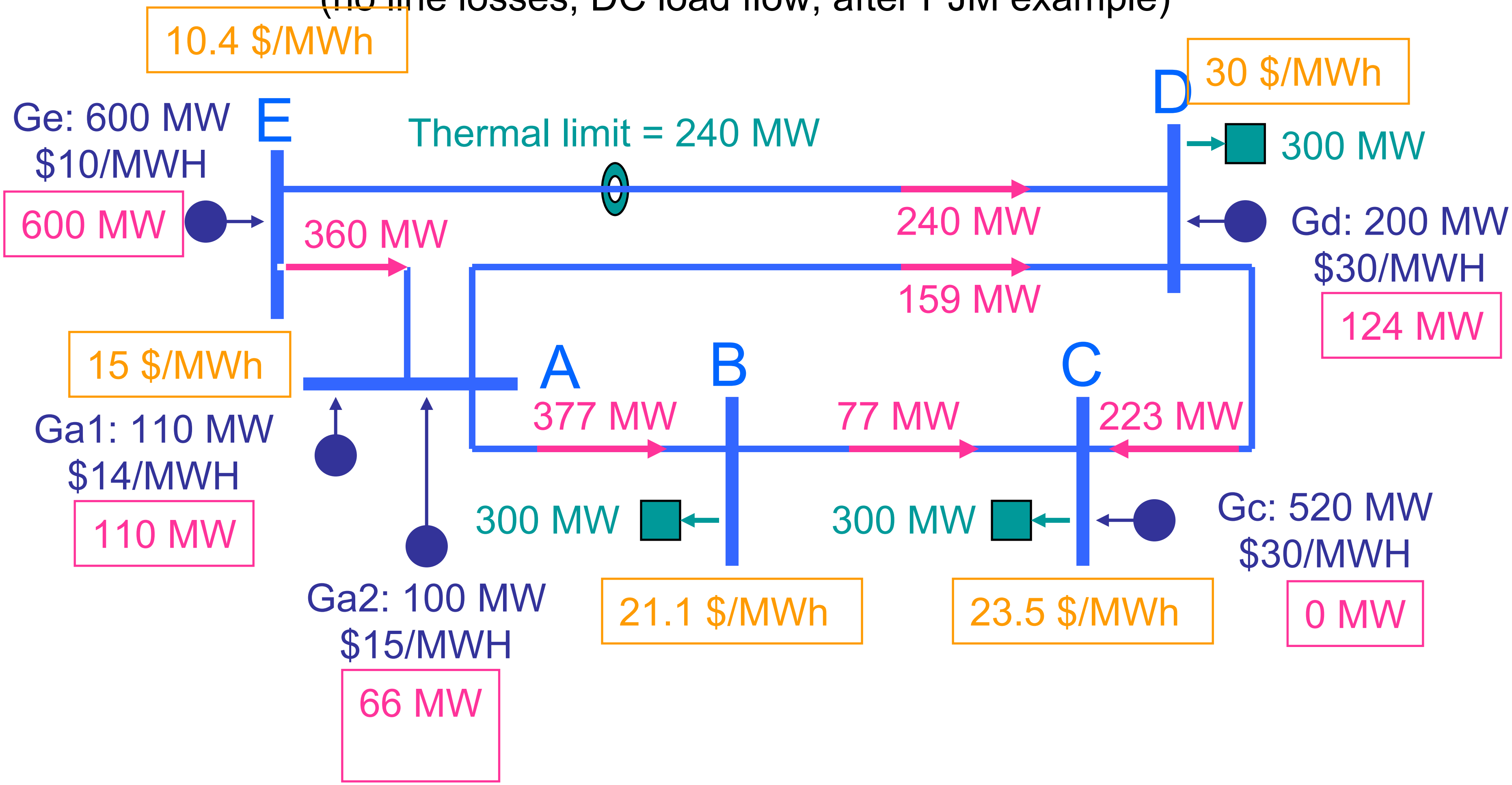
Line 1-2 has been disconnected

Nodal spot markets: 3-node meshed network
Implications

- Meshed network elements are mutually dependent:
  - Unless they can be independently controlled
  - Switching 'weak' elements off may even improve economic outcome (unlike radial network)
- Spot market alone gives perverse incentives:
  - Network earns more when flows are constrained
  - Some generators may benefit from constrained network operation

Five node example

(no line losses, DC load flow, after PJM example)



total dispatched generation = 900 MW = total load

Lessons from 5 node example

- Nodal prices for a 5 node network with a single line constraint can be computed:
  - Two marginal generators set local prices & remaining nodal prices derived from these:
    - Requires an accurate network model, including impedances & flow constraints
- Low price at Node E ($10.4 /MWh) because a 1 MW load incr. at Node E would be met by:
  - Increasing the output of Ga2 >1MW @ $15/MWh
  - Reducing the output of Gd <1MW @ $30/MWh
  - To give a net cost of $10.4 /MWh

Limits to the effectiveness of nodal markets

- For a given network, more nodal markets:
  - Mean fewer participants in each nodal market:
    - Local participants & network owners gain market power
    - Ancillary services, spot energy & risk harder to price
  - Require a more accurate network model
  - *There is a lower limit to the level of network detail that nodal markets can resolve*
- Regional markets provide one option:
  - Place major flow constraints on region boundaries:
    - Models of “notional interconnectors” then required
  - Resolve intra-regional network flow constraints by negotiation under regulatory supervision

Alternative models of AC networks for electricity spot markets

- Transport model
  - Models real power but ignores reactive power
  - Models series losses & flow constraints
  - Assumes independent flow on each element:
    - not appropriate for meshed networks
- DC load flow model:
  - Models real power but ignores reactive power
  - Models series losses & flow constraints
  - Models flow sharing between parallel elements

Alternative models of AC networks for electricity spot markets

- AC loadflow model
  - Models real & reactive power & nodal voltages
  - Accurate representation of network elements:
    - Series & shunt losses & reactive power
    - Thermal limits
    - Can model transformer tap-changers & reactive power resources
  - Extensive data requirements:
    - Network impedance data
    - Reactive power resources & voltage operating limits

Comparison of alternative models for AC networks

- Transport model (very abstract):
  - Judgement-determined parameters & constraints
  - Used in NEM to model “notional interconnectors”
- DC loadflow model (quite abstract):
  - Assumes voltage control is an ancillary service that can be de-coupled from network power flow
- AC loadflow model (least abstract):
  - Reactive power prices derived from node-voltage limits
  - Bids & offers can include voltage-value functions

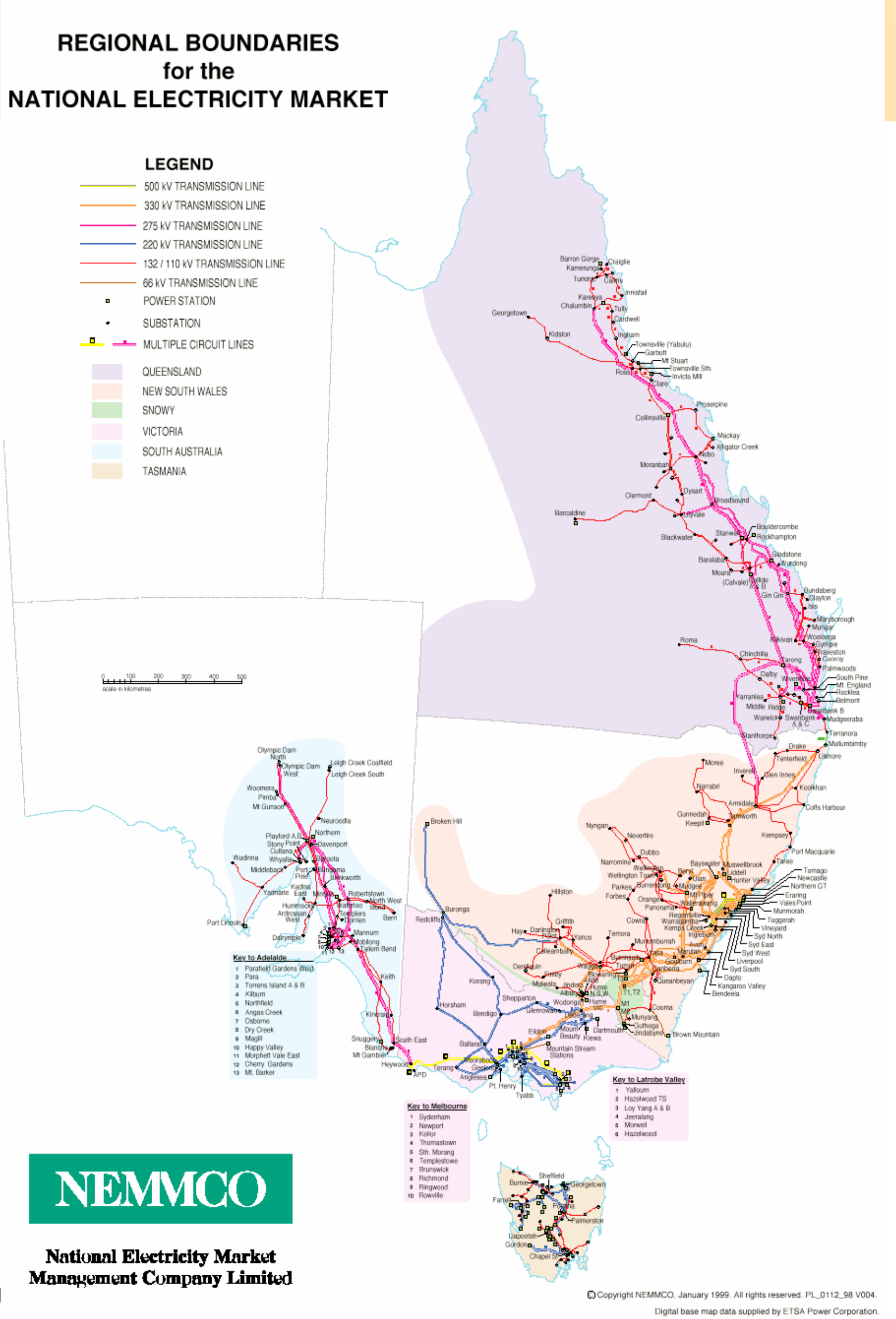
Conclusions on models #1

- A transport model sometimes adequate:
  - Used in NEM with ‘notional interconnectors’:
    - As yet no ‘loop flow’ effects between market regions
    - Voltage control treated as an ancillary service
  - Acceptable for an initial implementation
- DC loadflow models ‘loop flow’:
  - However network flow limits difficult to incorporate as voltage effects still ignored:
    - PJM market uses DC loadflow for real power flows but AC loadflow for reactive power flows

Scope of the NEM

- Queensland
- New South Wales & ACT
- Victoria
- South Australia
- Tasmania (on connection to the mainland)

NEM regions are indicated, and their boundaries need not be on state borders (e.g. two regions in NSW)



Key NEM features

- NEM covers all participating states:
  - A multi-region pool with intra-regional loss factors
  - Ancillary services, spot market & projections
  - Auctions of inter-regional settlement residues
  - Operated by NEMMCO (owned by states)
- Compulsory participants in NEM:
  - All dispatchable generators & links > 30 MW
  - Network service providers & retailers
- Contestable consumers may buy from NEM

NEC treatment of network losses & capital costs

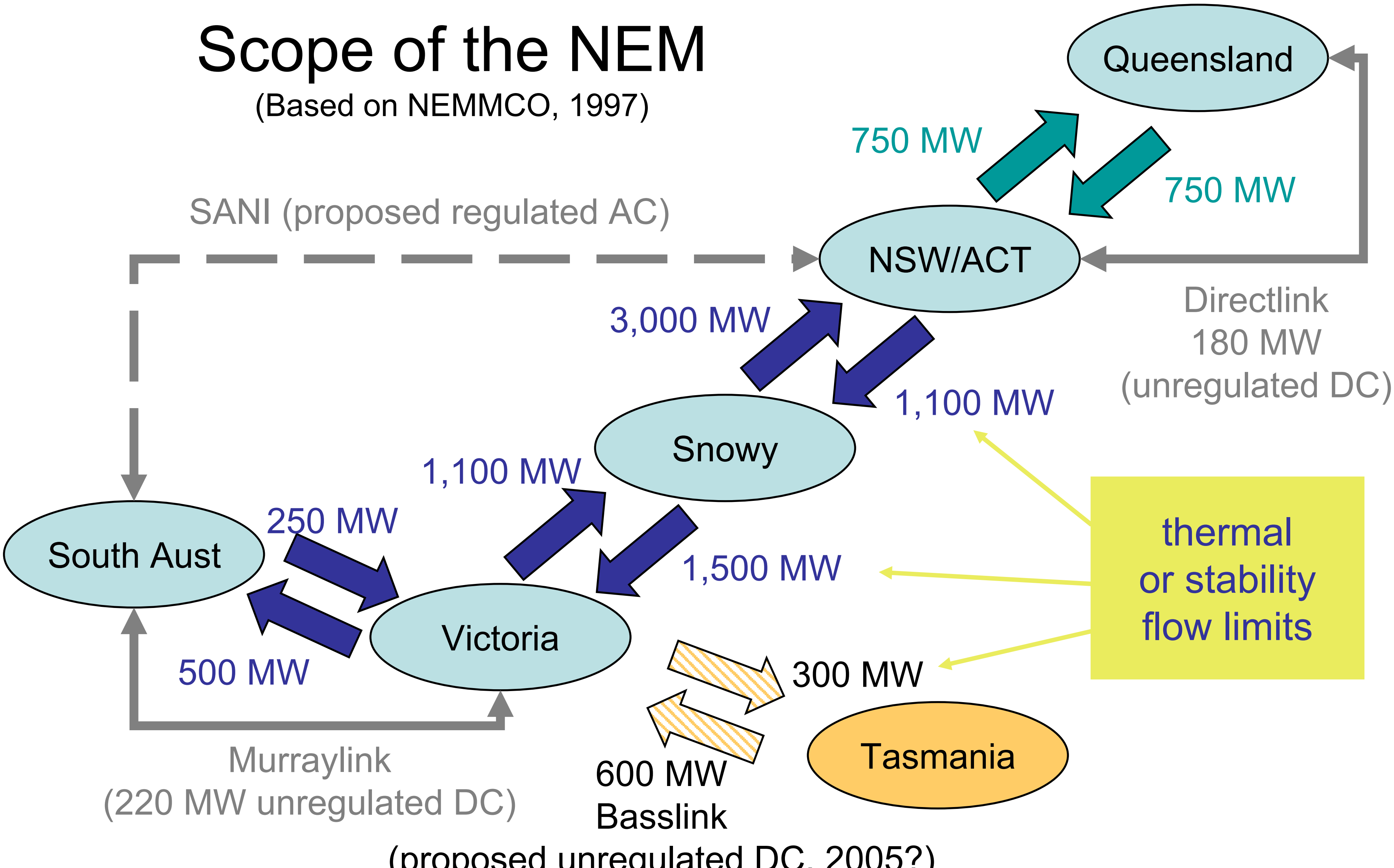
- NEC contains NEM rules & access regime:
  - Both address network issues
- National Electricity Market trading rules:
  - Notional regulated interconnectors & associated settlement residue auctions
  - Market network service provider (unreg intercon)
  - Intra-regional network loss factors & constraints
- Network access and pricing:
  - Revenue cap for regulated network service providers
    - Jurisdictional derogations modify access rules except in NSW

NEC treatment of network flow constraints

- NEMMCO documents inter- & intra- regional flow constraints:
  - these are inputs to the dispatch process
- Significant transmission constraints appearing 50 hours/y or more:
  - To be placed on market region boundaries:
    - where it is practical to reset the boundaries to do so

Scope of the NEM

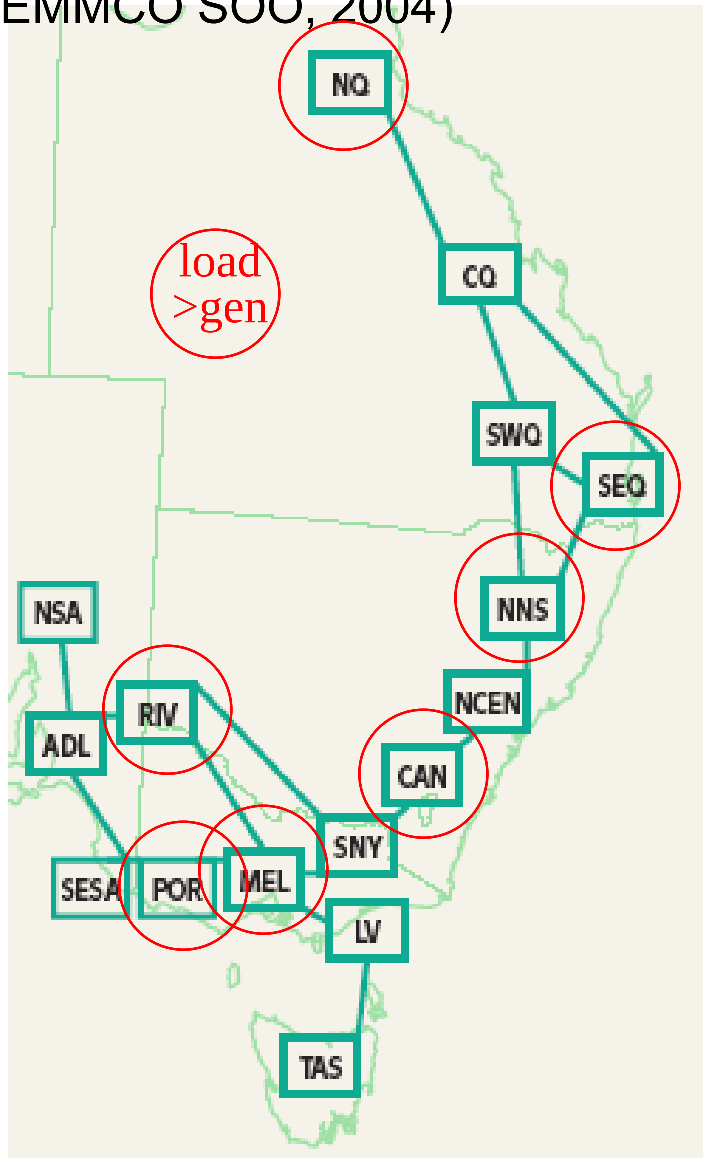
(Based on NEMMCO, 1997)



16 region NEM model

(NEMMCO SOO, 2004)

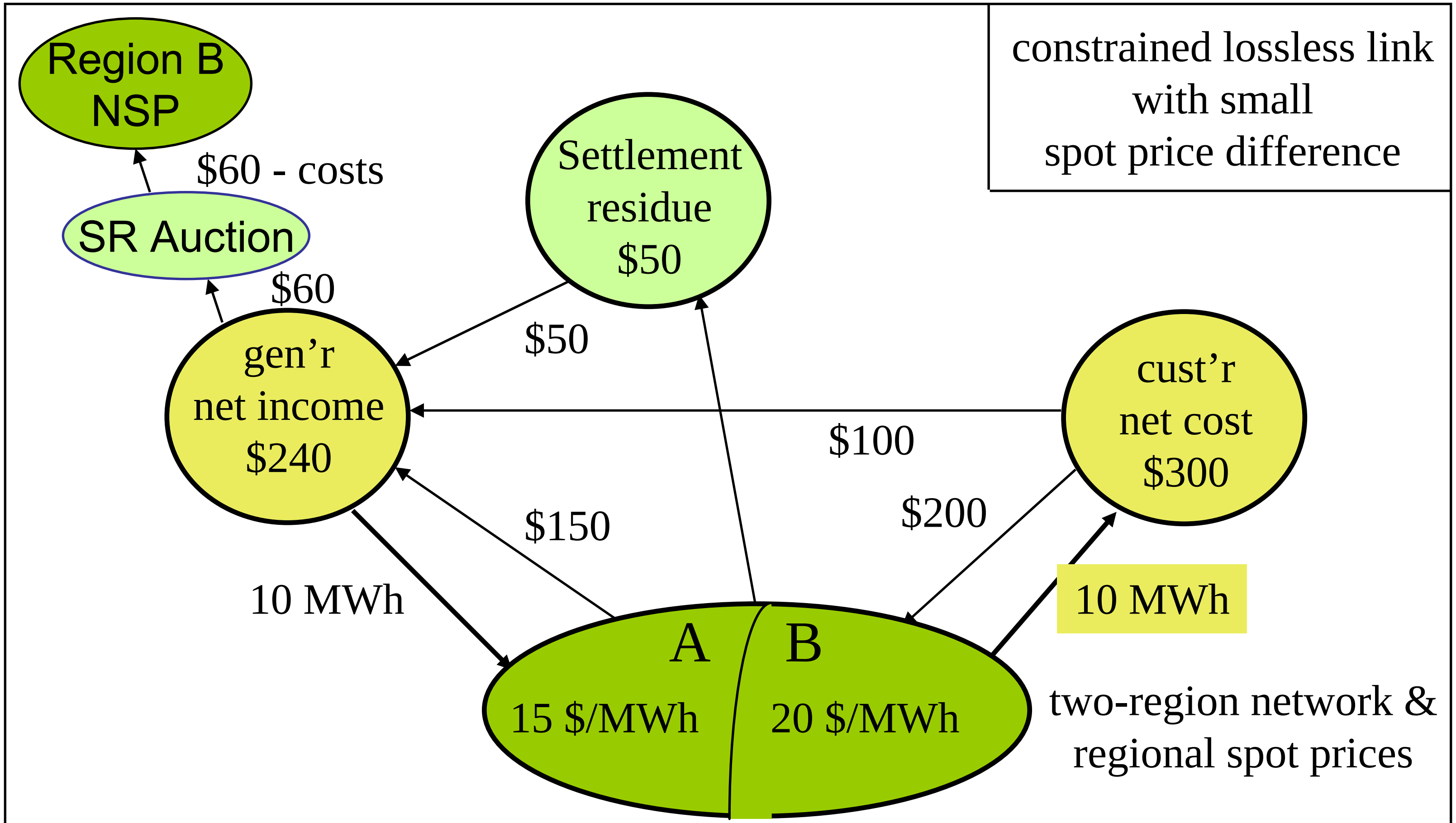
Node	Pk Ld (MW)	Gen Cap (MW)	Net Gen (MW)
NQ	1250	800	- 450
CQ	1900	4150	2250
SWQ	200	2150	1950
SEQ	4350	1450	- 2900
NNS	800	150	- 650
NCEN	10000	11650	1650
CAN	800	300	- 500
SNY	800	3900	3100
MEL	5750	800	- 4950
LV	900	7000	6100
POR	650	0	- 650
SESA	100	150	50
RIV	500	50	- 450
ADE	2100	2250	150
NSA	200	1100	900
TAS	1500	2500	1000



Risk management with nodal pricing – NEM arrangements using spot market settlement residues

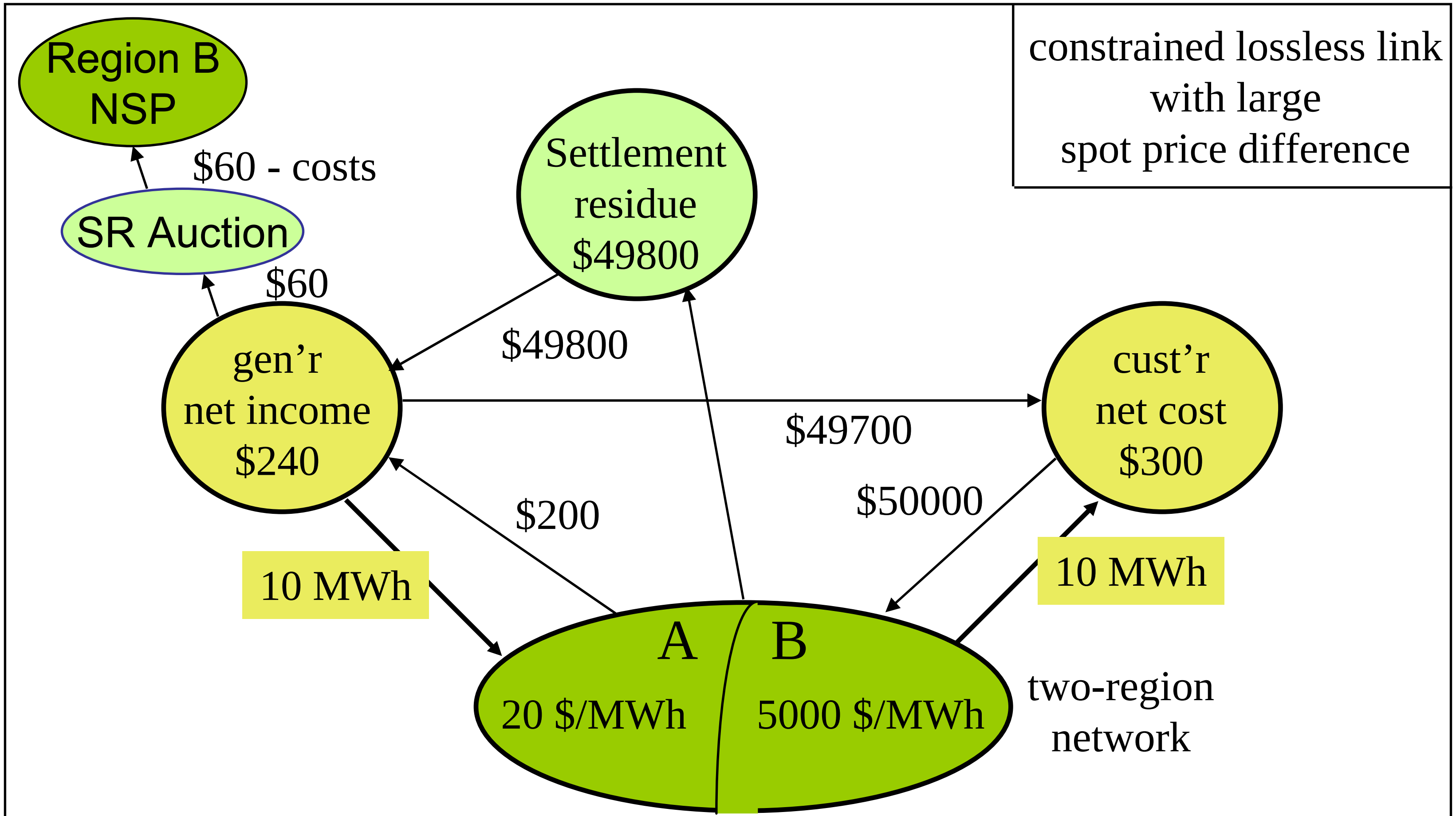
- A hedge against differences between regional spot prices for one direction of flow
  - Settlement residue for regulated interconnectors:
    - Difference in regional reference prices multiplied by interconnector power flow for each spot market interval
- NEMMCO runs 3-monthly auctions of settlement residue
- An incomplete hedge:
  - doesn't cover interconnector losses or outages
  - Doesn't cover unregulated interconnectors

Inter-regional hedge example #1



Generator sells a 10 MWh hedge contract on region B price to customer at $30 MWh & buys a directed 10 MWh hedge (B-A) from NEMMCO SR auction at cost of 6 $/MWh (expected spot price difference between regions)

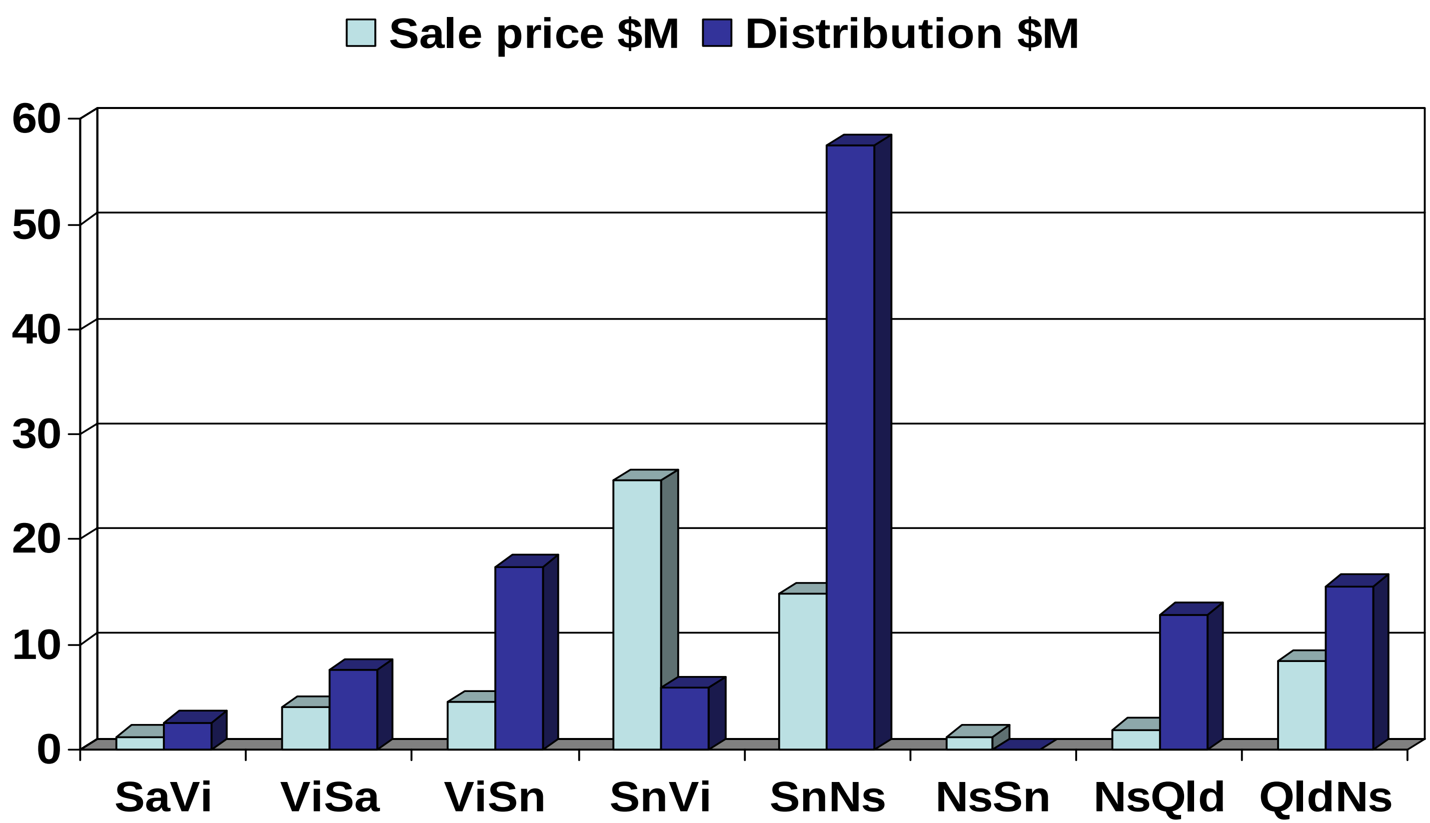
Inter-regional hedge example #2



Generator sells a 10 MWh hedge contract on region B price to customer at $30 MWh & buys a directed 10 MWh hedge (B-A) from NEMMCO SR auction at cost of 6 $/MWh (expected spot price difference between regions)

Annual outcomes of NEM SRAS for FY03

(SRC report FY03 see www.nemmco.com.au)



NEM unregulated interconnector

- An unregulated interconnector (MNSP):
  - Submits offers into the NEM spot market & retains spot market income
  - Does not participate in SRA process but can independently sell inter-regional hedges
- MNSP hedge versus SRA auction:
  - MNSP not restricted on hedge design or duration but faces similar issues (availability,losses)
  - SRA auction competes for hedge volume & sets a benchmark price

NEC Treatment of Transmission & Distribution Pricing (Chapter 6)

- Principles for network pricing:
  - Promote competition in the provision of services
  - Be transparent & non-discriminatory
  - Seek similar outcomes to a competitive market
- ACCC Regulatory test for T&D augmentation:
  - Reliability:
    - Minimises cost of meeting an objective reliability criterion
  - Market benefit:
    - Maximises NPV of market benefit having regard to alternative projects & market scenarios

Transgrid's interpretation of allowable market benefits (QNI preliminary assessment, 03/04)

Allowable Market Benefits	Description of Benefit
Production Efficiency Benefits	Reduction in fuel consumption of higher-priced sources Reduction in transmission losses Reduction in ancillary services
Capital Efficiency Benefits	Deferral of generation plant that would be required to maintain reliability reserve margins Deferral of generation plant that could be expected to enter the market in response to sustained high pool prices Reduction in capital costs Reduction in O&M costs Deferral of other transmission investments
Consumer Efficiency Benefits	Reduction in voluntary Demand Side Participation Reduction in involuntary load shedding

Transmission pricing
(existing arrangements; under review)

- Allowed annual revenue (AAR) for network
  - Set by regulator (ACCC), based on:
    - 'Optimal deprival' value of the network assets:
      - How would each asset be replaced today if it disappeared?
        - » Considering network & distributed resource options
      - Existing assets and audited five-year expansion plan
    - Allowed rate of return:
      - Depends on the assessed risk of the business
  - Five year reset, (CPI-X) annual adjustment:
    - Pressure to control costs between assessments
    - Incentive to further reduce costs, because profits are retained at least until the next assessment

Transmission pricing within regions

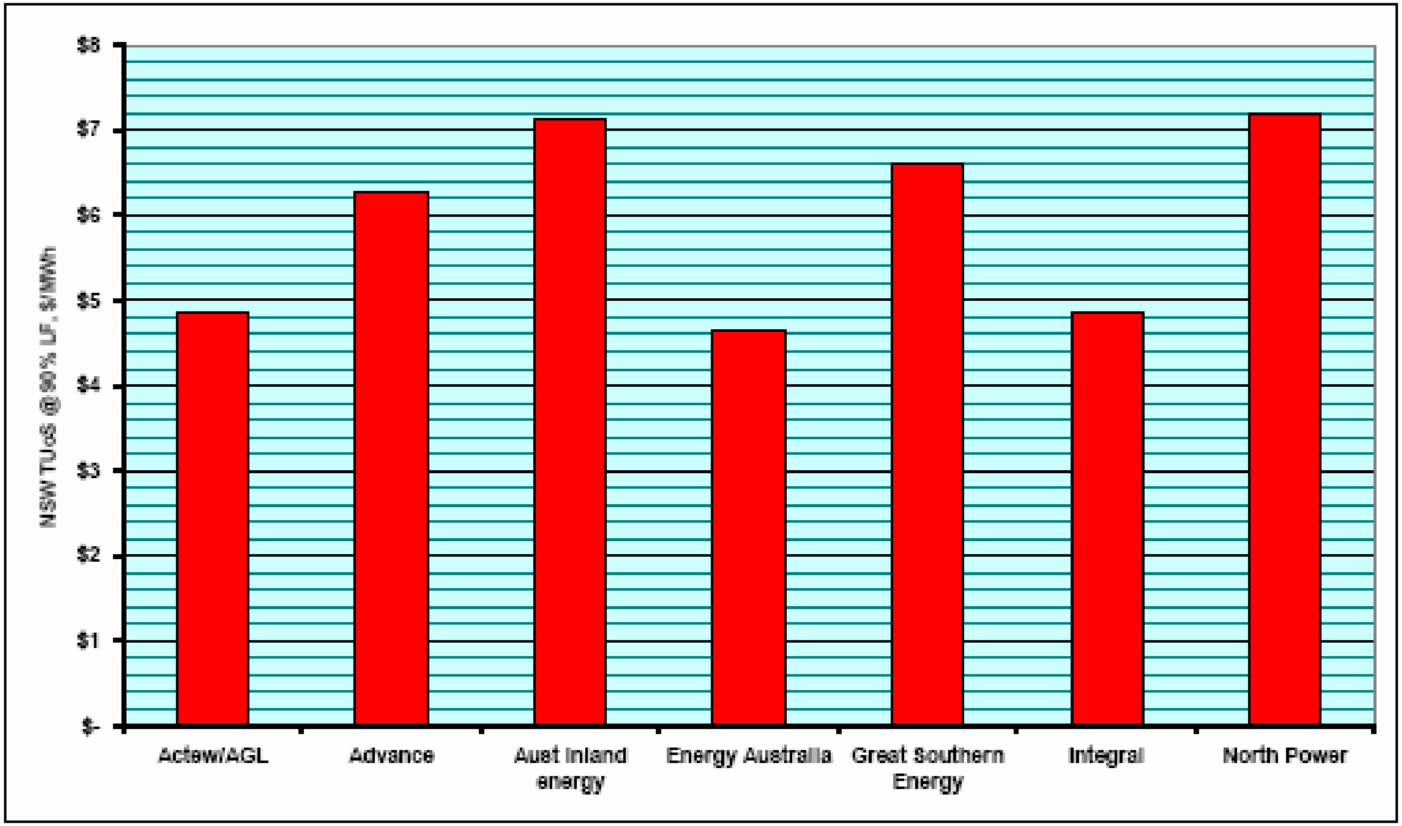
(existing arrangements; under review)

- Recovering AAR from network users
  - Based on assessed use of the network
  - Network elements considered individually:
    - Overall network AAR is assigned to individual elements in proportion to their optimised replacement cost
  - Each network element allocated to a category:
    1. Serve particular network users (*entry or exit*)
    2. Provide a *common service* to all network users
    3. Shared by market customers in an identifiable way:
       - these costs to be allocated in an ‘equitable’ fashion
       - At present using “Cost Reflective Network Pricing”

TUOS charges for customers

- Typically calculated on
  - peak+shoulder hours energy rate
  - Peak demand rate

(BCSE, Cogeneration review, 2001)



Distribution system pricing

- Regulation of distributors under State regulation
  - Eg. NSW: IPART
  - Arrangements differ by State

Distributor investment considering distributed resources

(NSW Demand Management Code of Practice, 2004)

Inform the market via annual plan

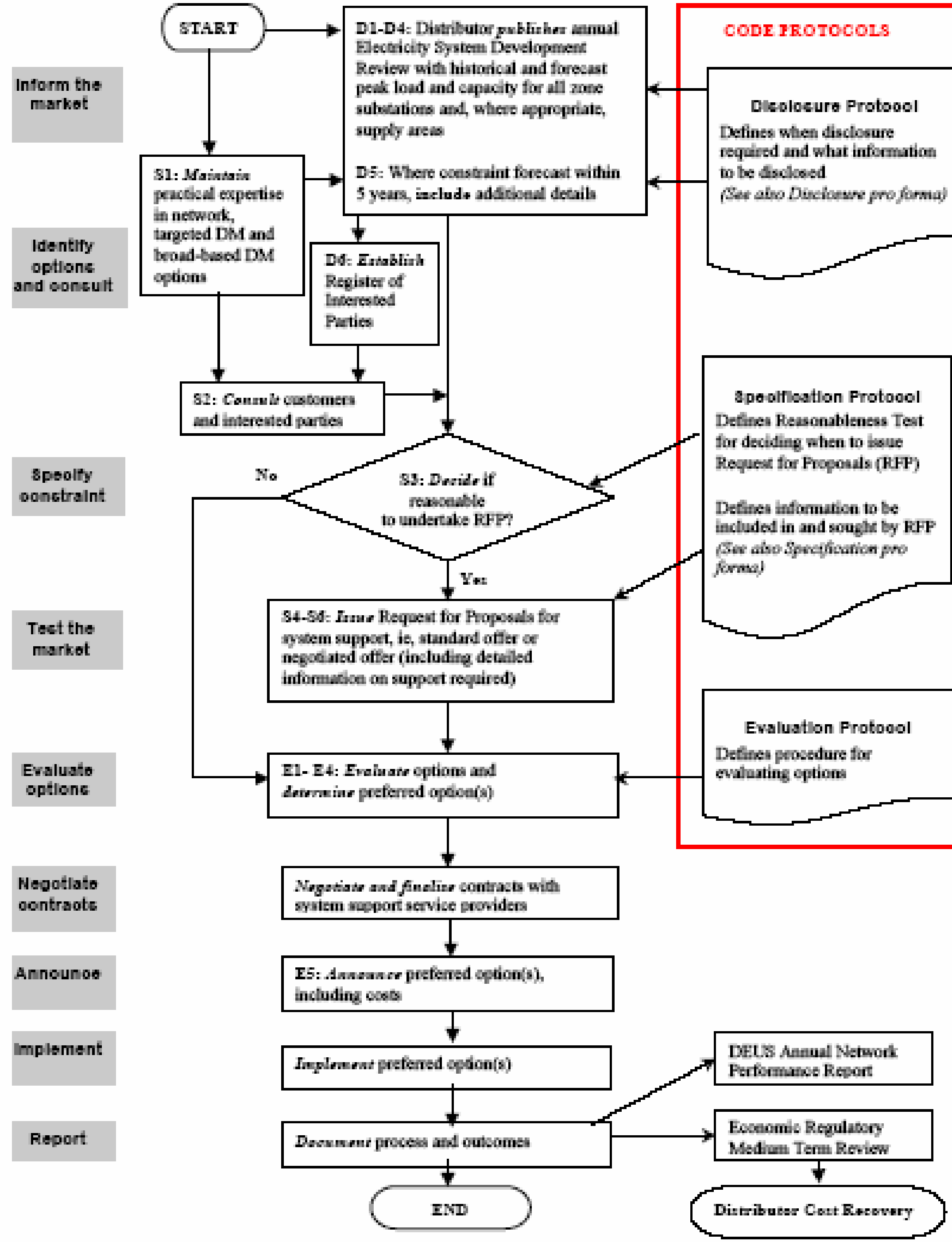
Specify constraints,
test the market &
evaluate options

DR Offer(s) cheaper:
Negotiate contract(s) with DR providers
(revert to network option if negotiation fails)

Network option cheaper:
Proceed with preferred network option

Report outcomes & update plans

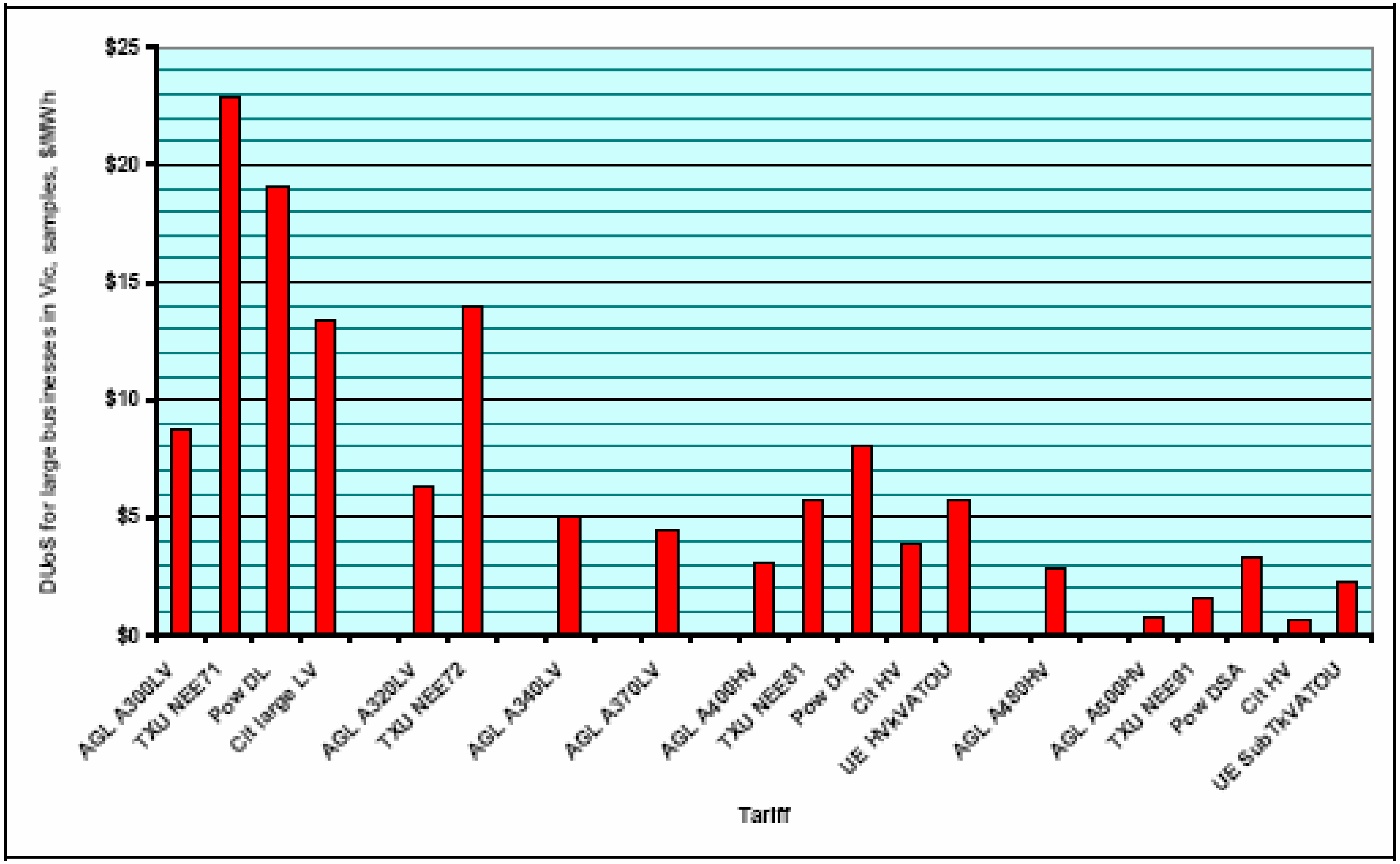
NSW Demand Management Code of Practice for Distributors (May 2004)



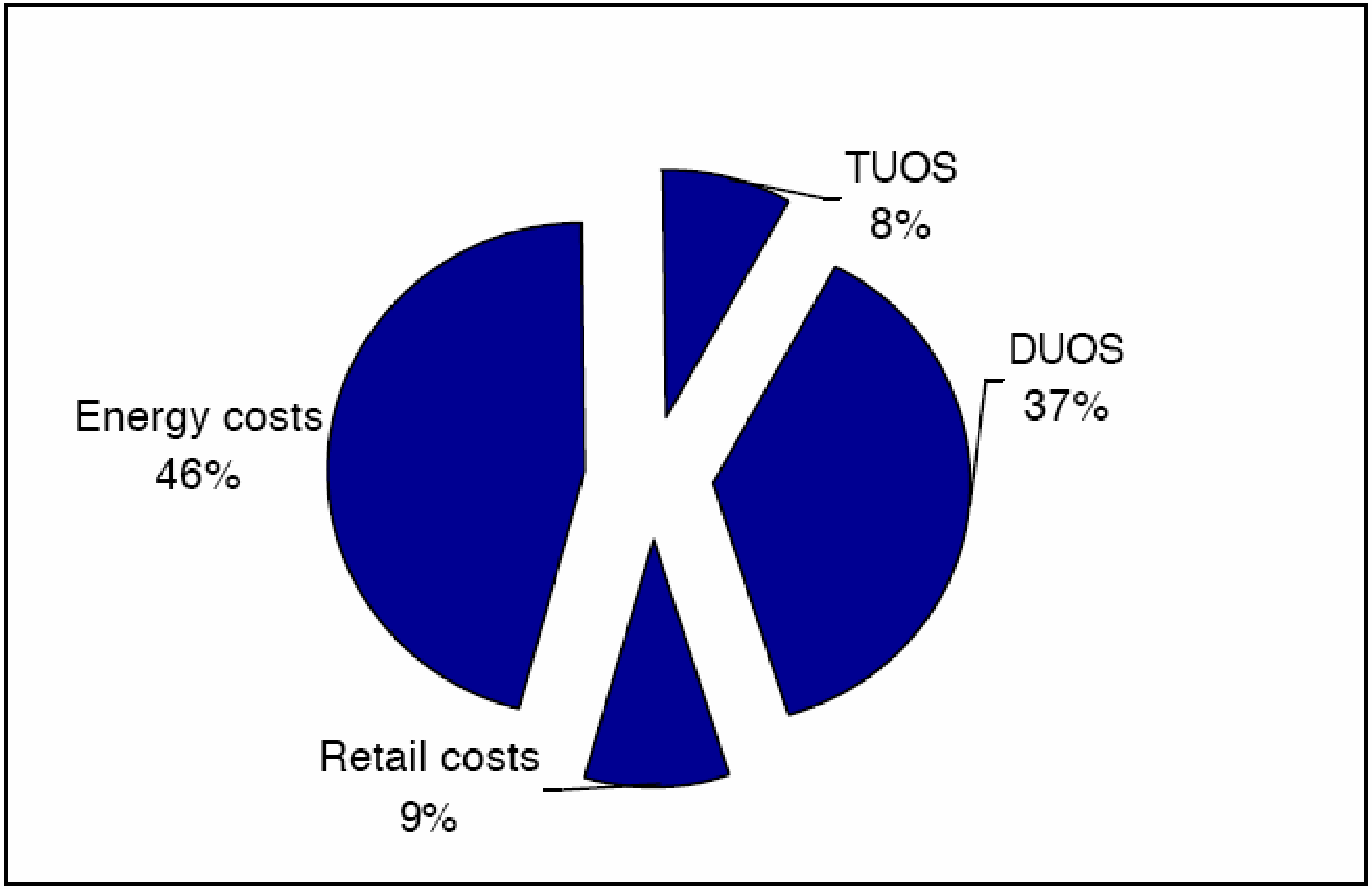
DUOS charges for customers

(BCSE, Cogeneration review, 2001)

- Figure 20 Sample of typical Victorian distribution charges

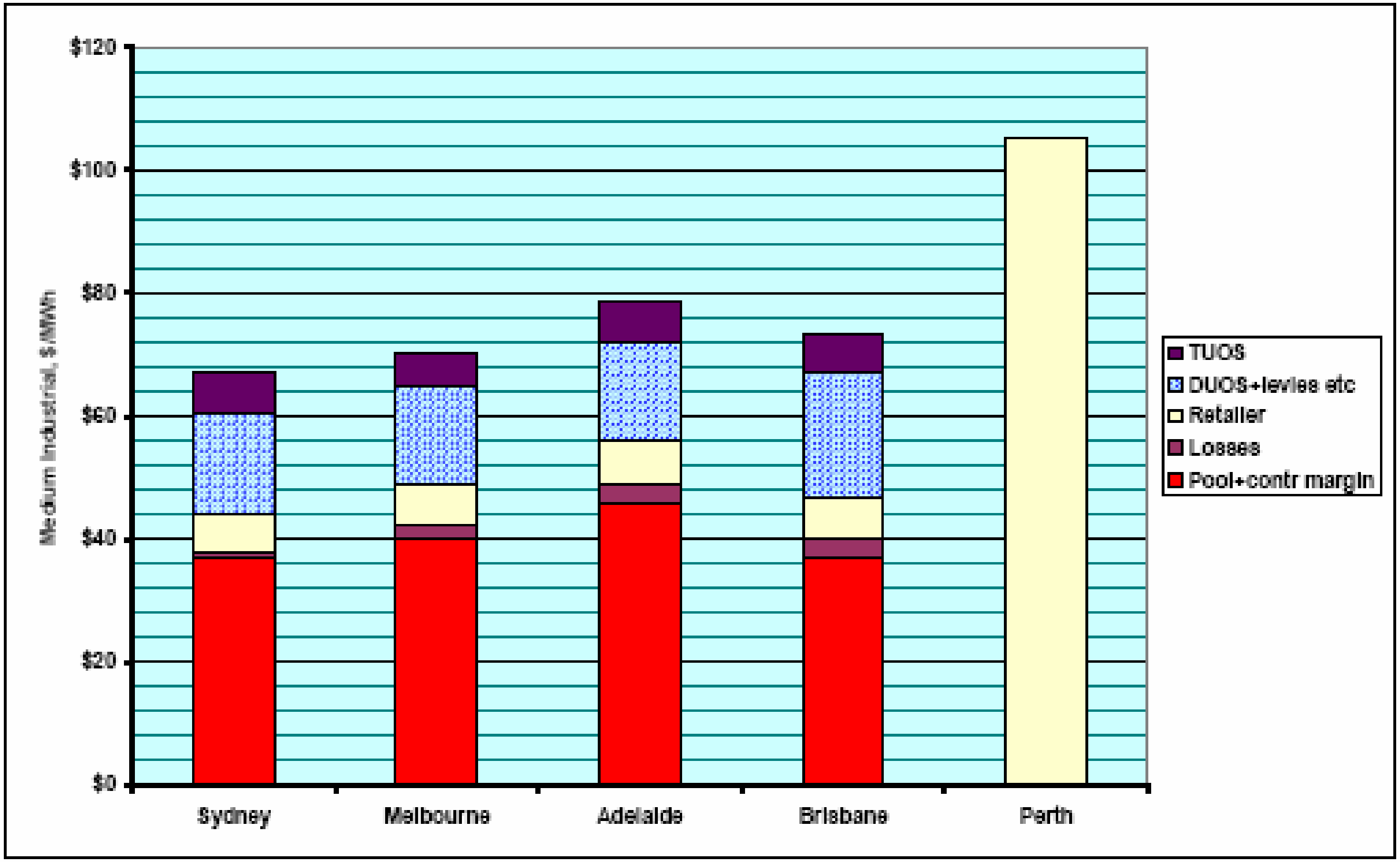


Typical NSW residential electricity bill (IPART, DNSP Review Issues Paper, 2003)



Typical charges for medium industrial customers

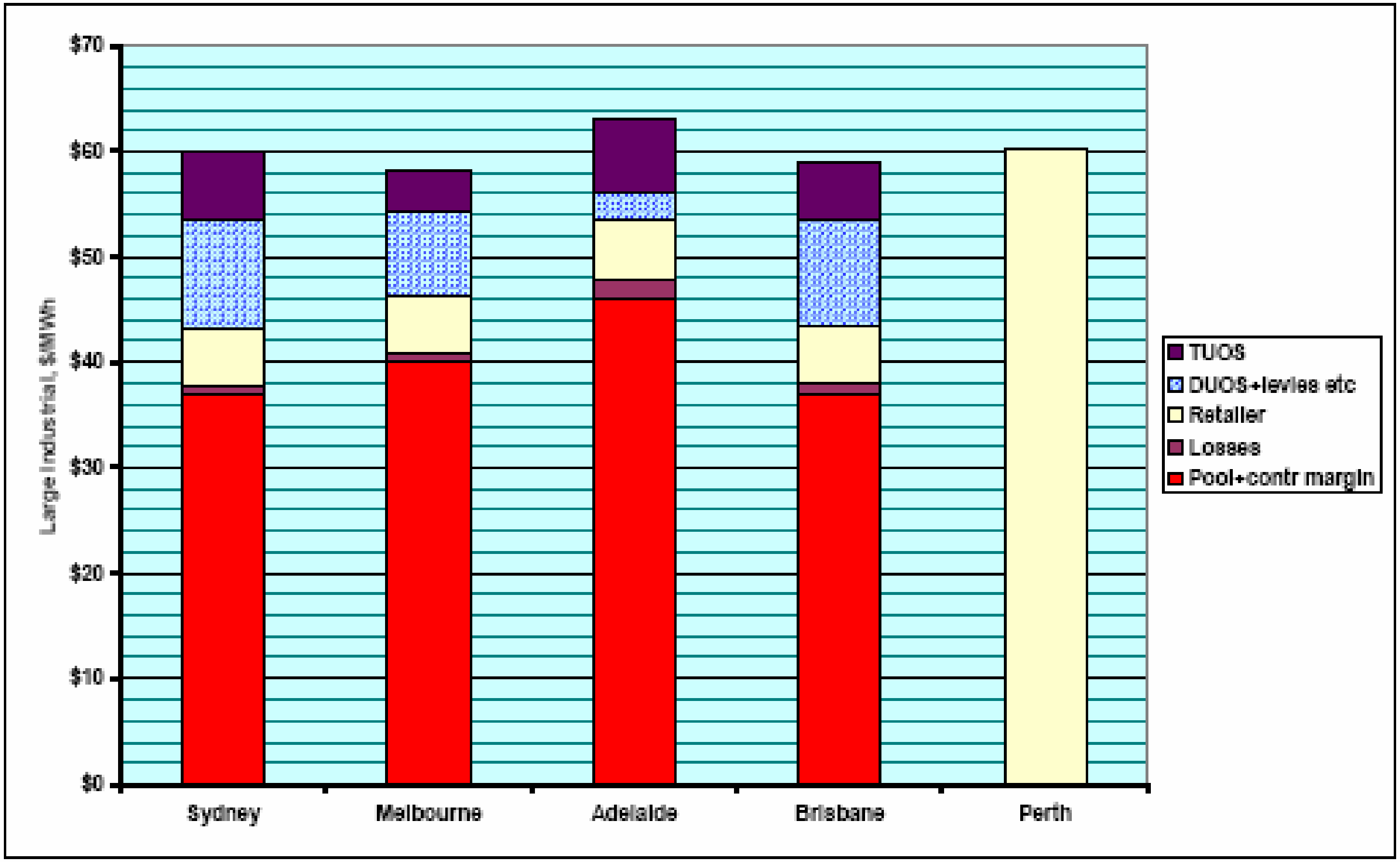
- Figure 30 Indicative delivered electricity charges - medium industrial



(BCSE, Cogeneration review, 2001)

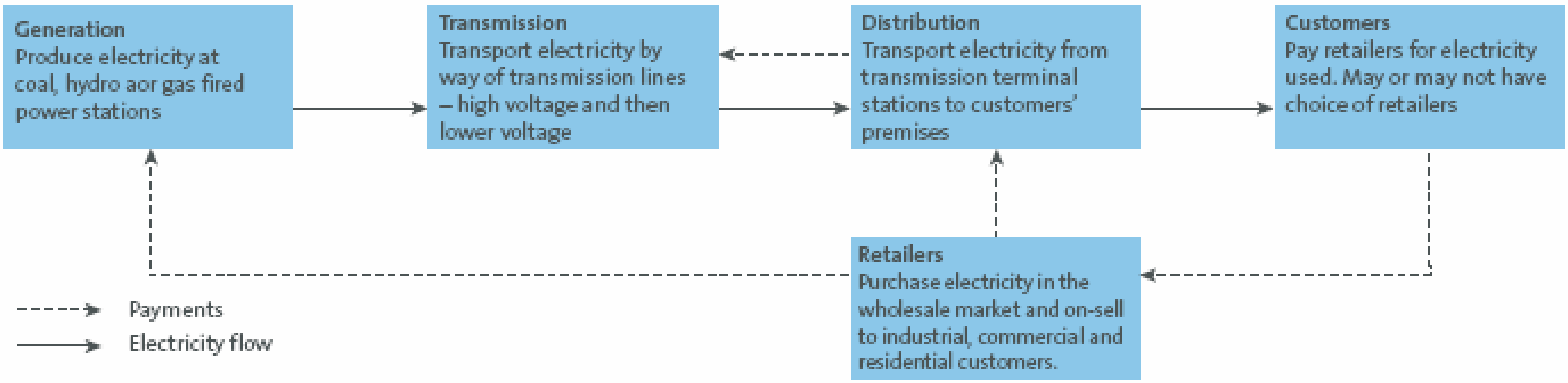
Typical charges for large industrial customers

- Figure 31 Indicative delivered electricity charges - large industrial



(BCSE, Cogeneration review, 2001)

Financial flows for network services in NEM



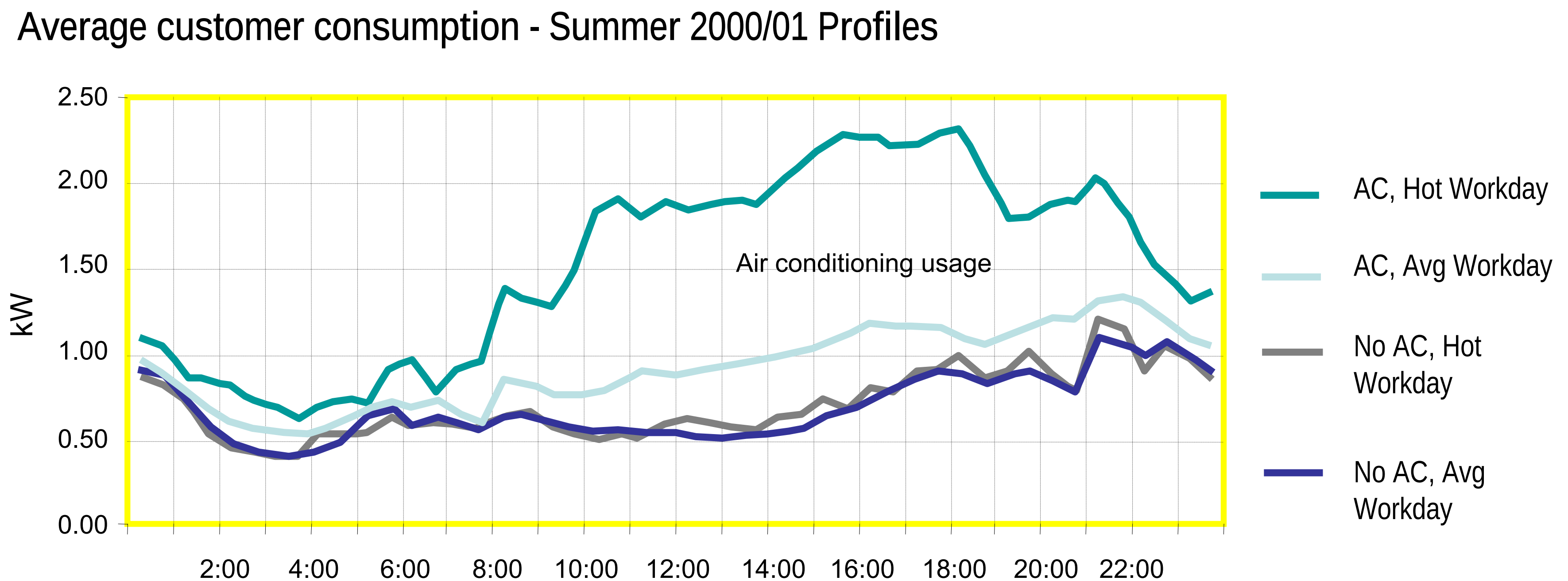
(AMP Capital, 2002)

Av. small consumer profiles in Sydney 2000/1 Summer

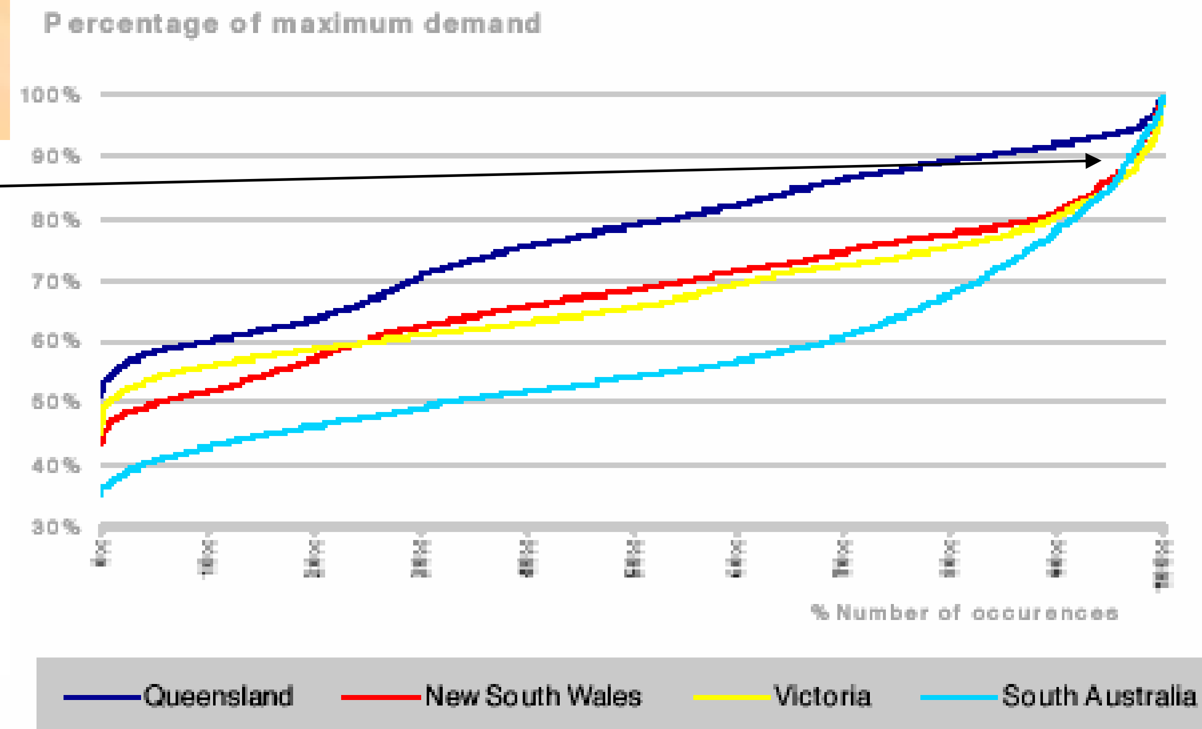
(H Coleburn, Energy Australia, August 2001)

Air-conditioning load is very temperature sensitive:

- A/C load on hot summer day much greater than on average summer day
- Load for consumers without A/C show much less temperature sensitivity



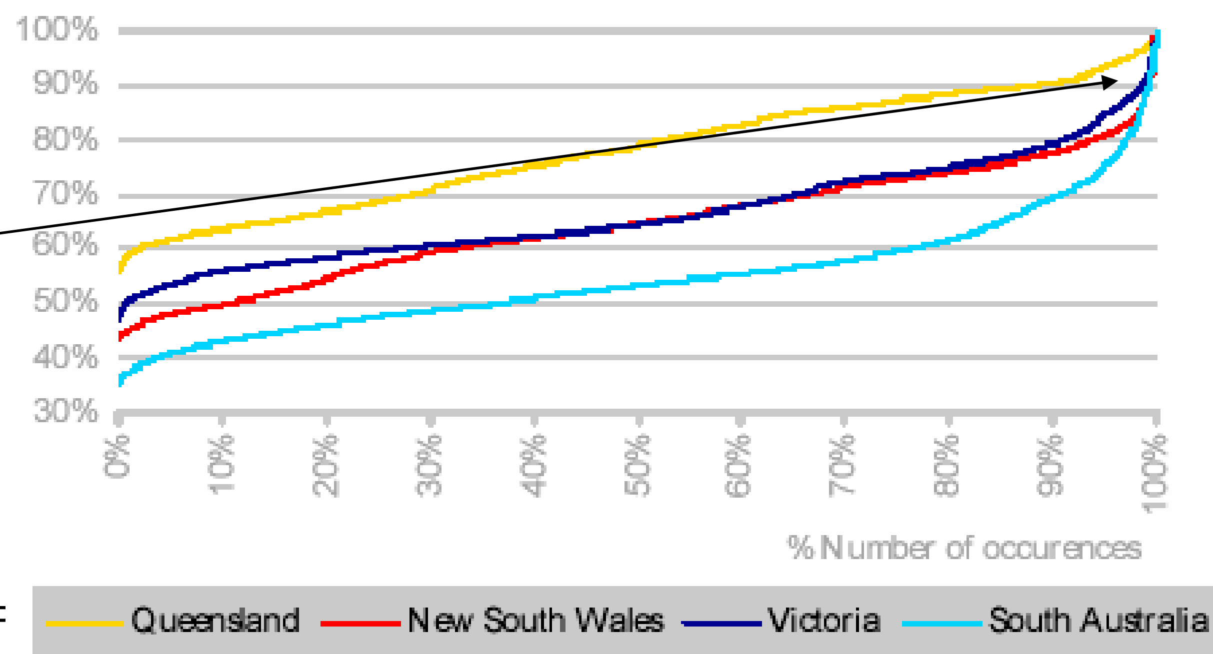
In 2001 NSW load >90% peak for ~5% of time



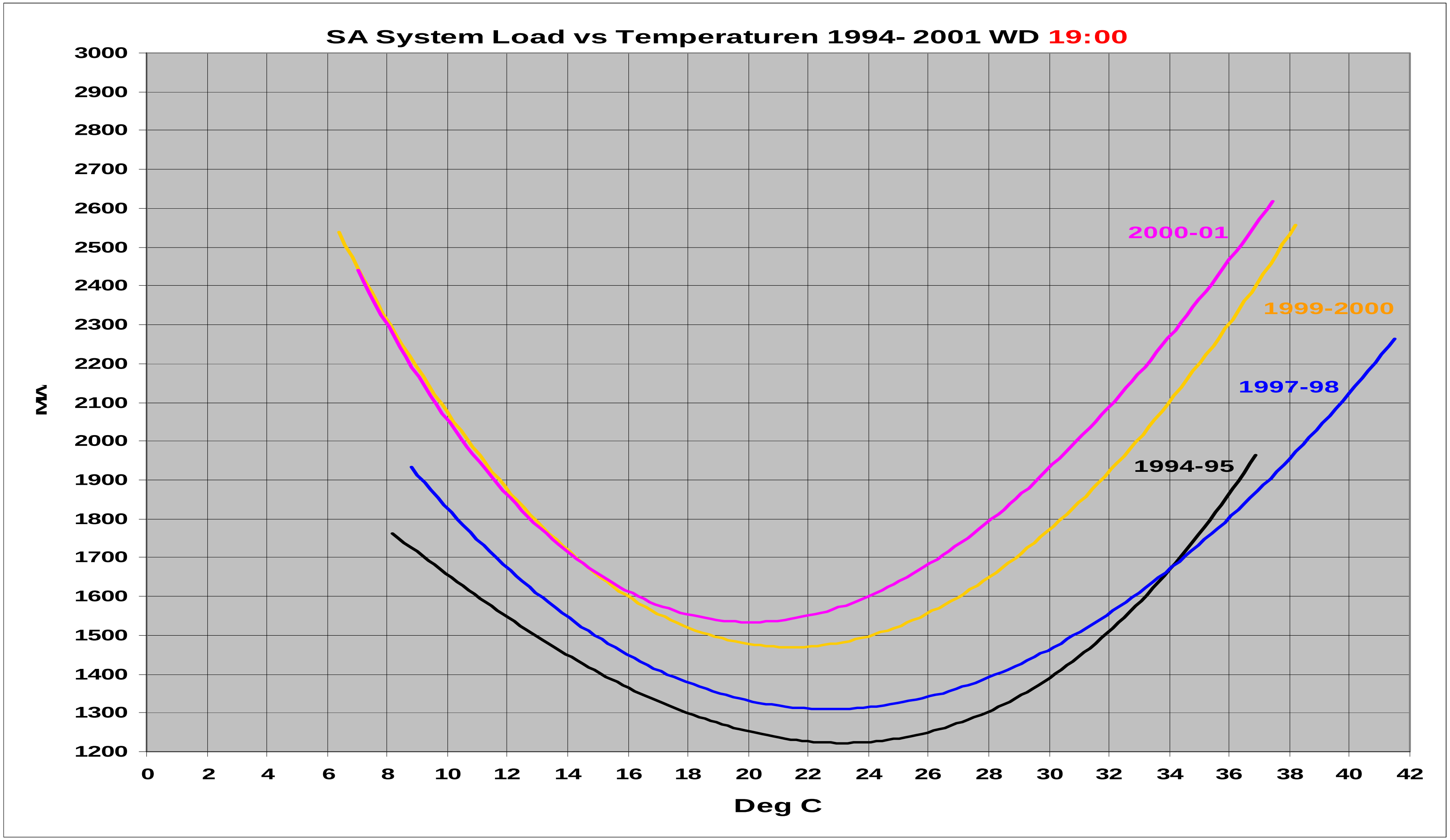
NEM load duration curves, January-March 2001 & 2003

(NECA quarterly Market Statistics)

In 2003 NSW load >90% peak for <2% of time



Growing temperature sensitivity of demand in South Australia (SA DM Taskforce, 2002)



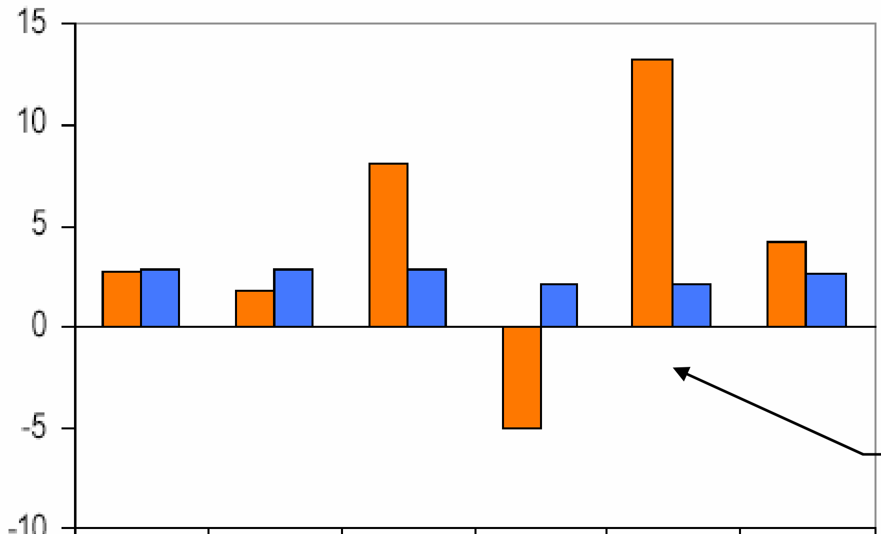
EnergyAustralia summer peak demand

(EA submission, IPART DNSP review, 2003)

Summer peak actual vs forecast

1999 - 2003

Annual Growth (%)



	1999	2000	2001	2002	2003	Avg
Actual	2.8	1.7	8.1	-5	13.3	4.2
1998 Forecast	3	3	3	2	2	2.6

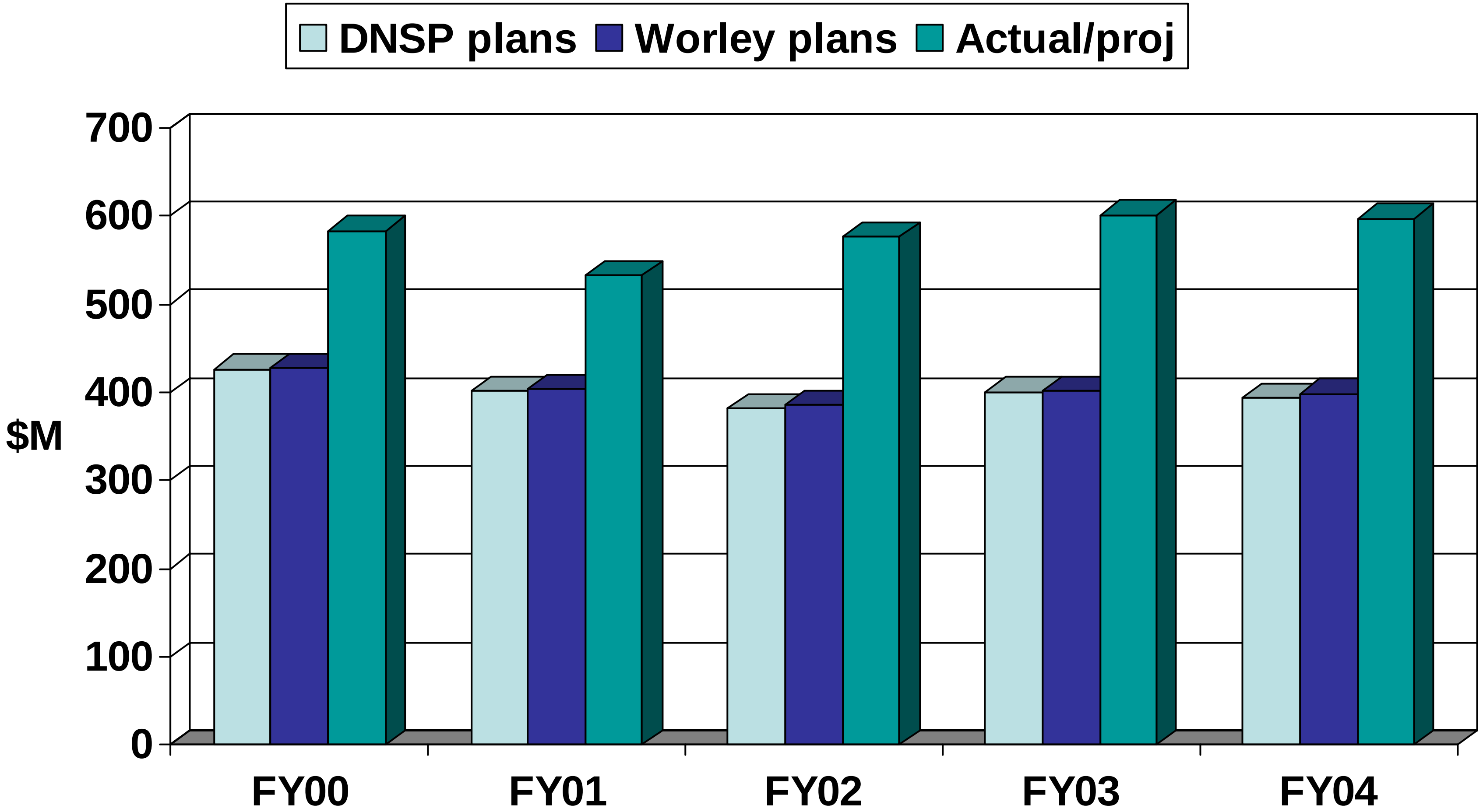
Summer of Year

Actual summer demand growth

- EnergyAustralia moving to summer peaking
- Shape of summer demand de-rates existing capacity.

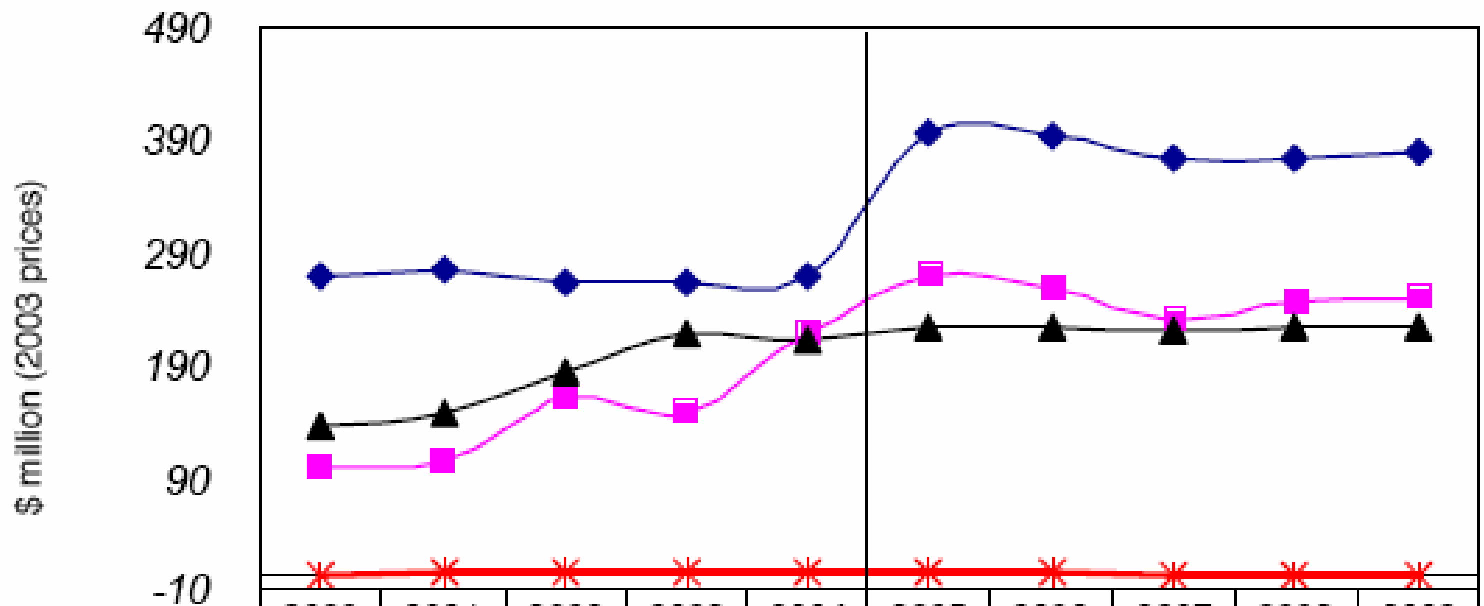
Uncertain weather-driven needle peak demand

Actual & projected DNSP capital expenditures (IPART, DNSP Review, 2003)



Capital expenditure greater than expected due to unanticipated growth in demand

NSW distributor actual & forecast capital expenditure (IPART, Dist Pricing Draft Rpt, 2004)



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Energy Australia	271	275	264	263	270	398	394	374	375	379
Integral Energy	101	106	162	148	218	270	257	230	248	249
Country Energy	138	148	185	218	213	225	224	222	224	224
Australian Inland	3	3	4	3	5	3	3	3	2	2

Conclusions

- Network services:
  - Vital to an electricity industry but hard to separate from generation & demand-side services
- Network services in a restructured industry:
  - HV transmission services can be:
    - Modelled in an electricity market
    - Made partly competitive
  - Sub-transmission & distribution:
    - Regulated at present, likely to remain so
    - Can be partly contested by distributed resources