MANAGING THE COSTS AND RISKS OF NEW GENERATION

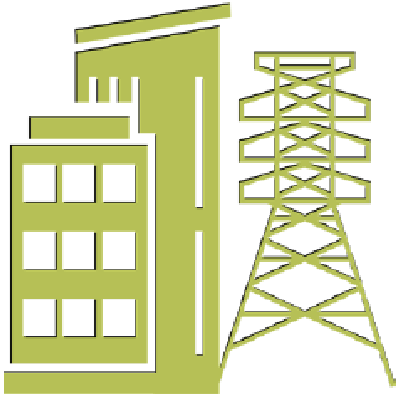
COORDINATION OF GENERATION AND TRANSMISSION INVESTMENT

PUBLIC WORKSHOP
18 OCTOBER 2019

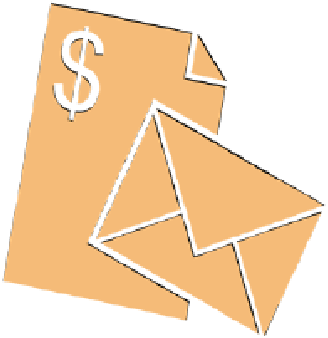
Agenda

1. Welcome
2. Need for reform
3. Overview of proposal
4. How this works in practice
5. Impact analysis
6. Need for renewable energy zones
7. Overview of renewable energy zones
8. Next steps

What the review is tasked with



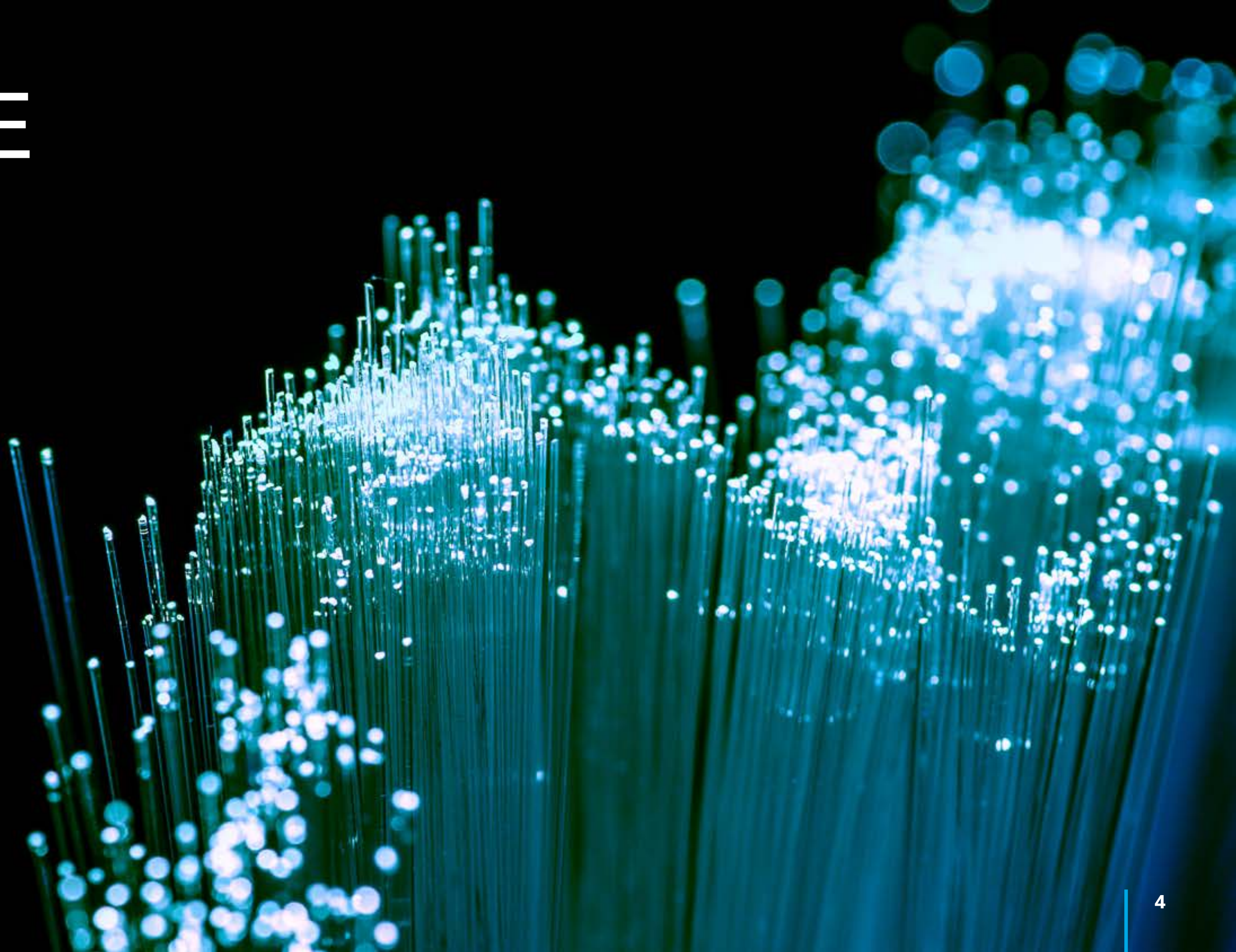
Access reform



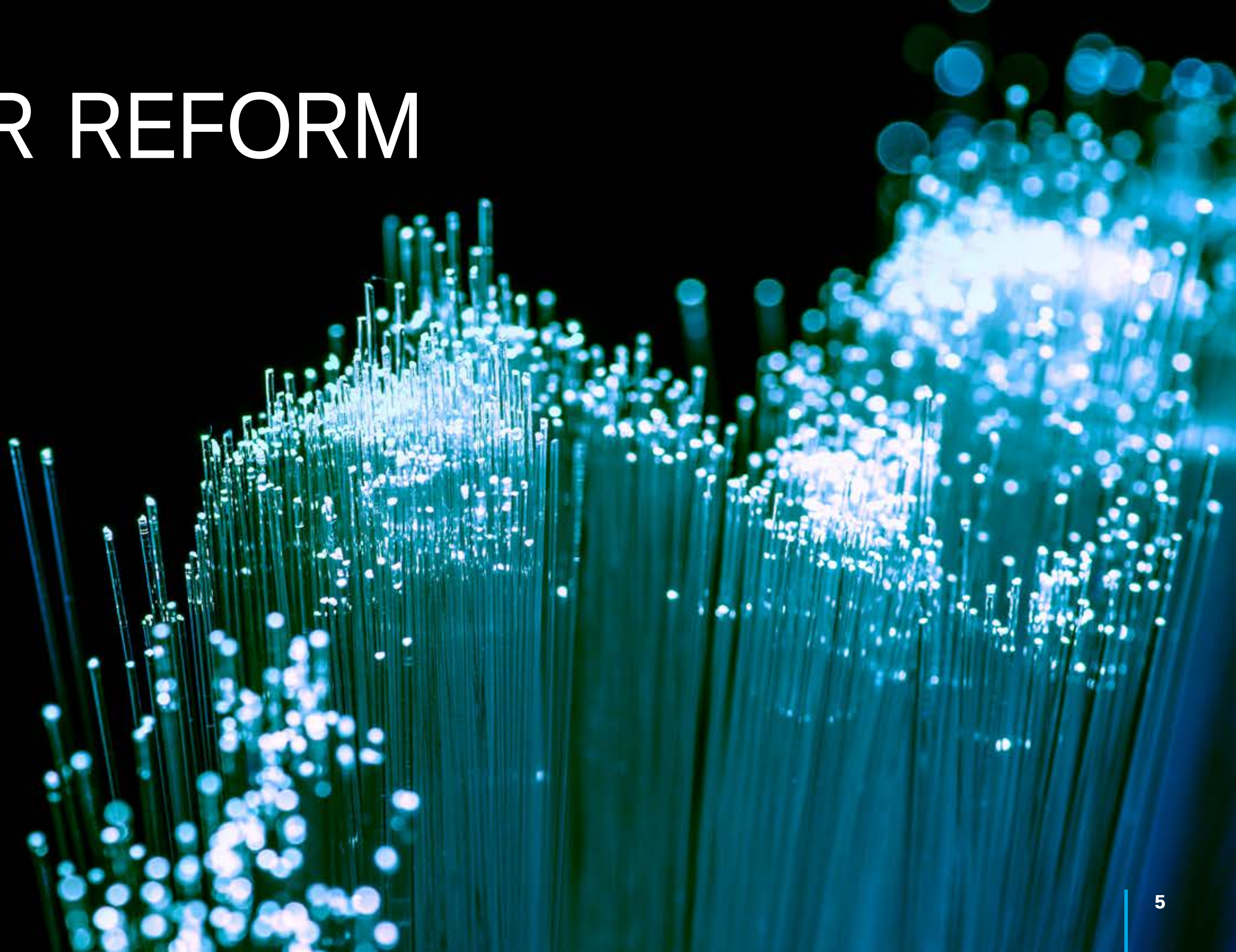
Charging reform

We are prioritising access reform based on stakeholder feedback that it is most urgent

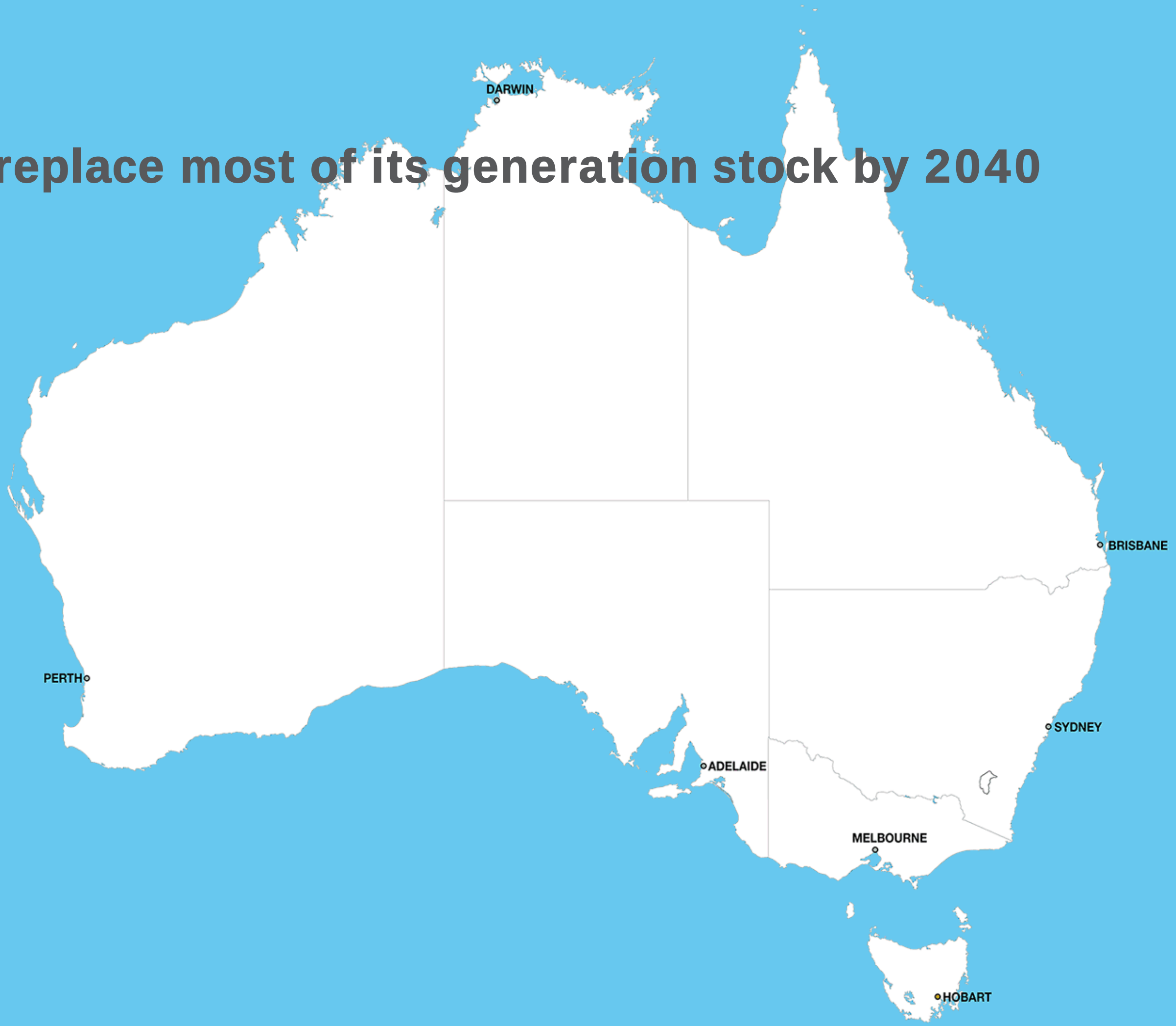
WELCOME



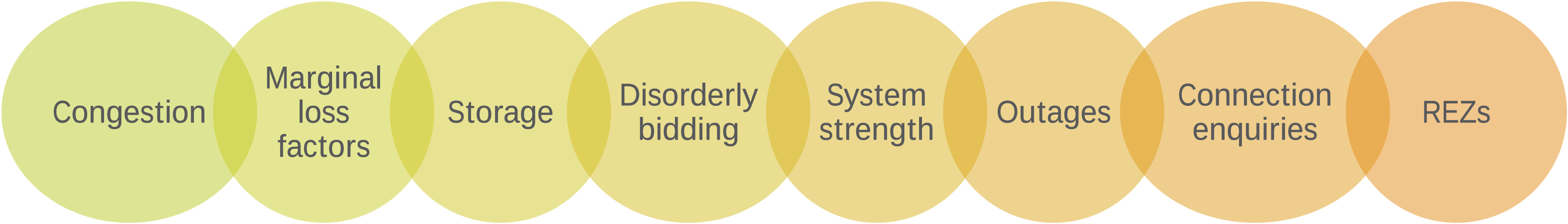
NEED FOR REFORM



The NEM will replace most of its generation stock by 2040



Need for access reform



Generators, consumers and transmission businesses are facing worsening and related issues as the electricity market transitions.

Access reform is needed now because the existing approach is no longer sustainable

OVERVIEW OF PROPOSAL

Our proposal for access reform – adapted for stakeholder feedback

1. **Wholesale electricity pricing**

Generators and storage receive a local price that better **reflects the marginal cost** of supplying electricity at their location in the network

2. **Financial risk management**

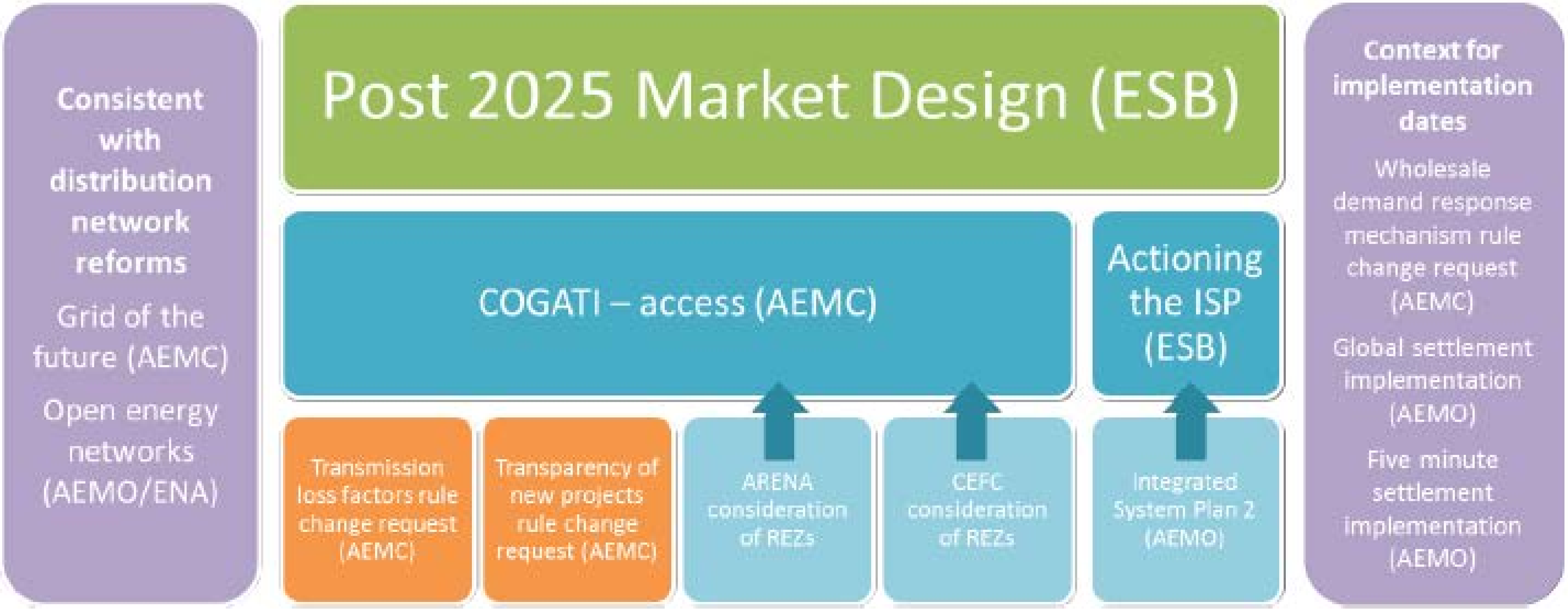
Generators and storage are better able to **manage the risks of congestion** by purchasing a financial transmission right

3. **Transmission planning and operation**

Transmission planning is **informed** by the purchase of transmission hedges, with the cost of transmission investment no longer solely recovered directly from consumers

Based on stakeholder feedback, we are pursuing only the first two elements of the proposed access model

Interaction with other key reforms



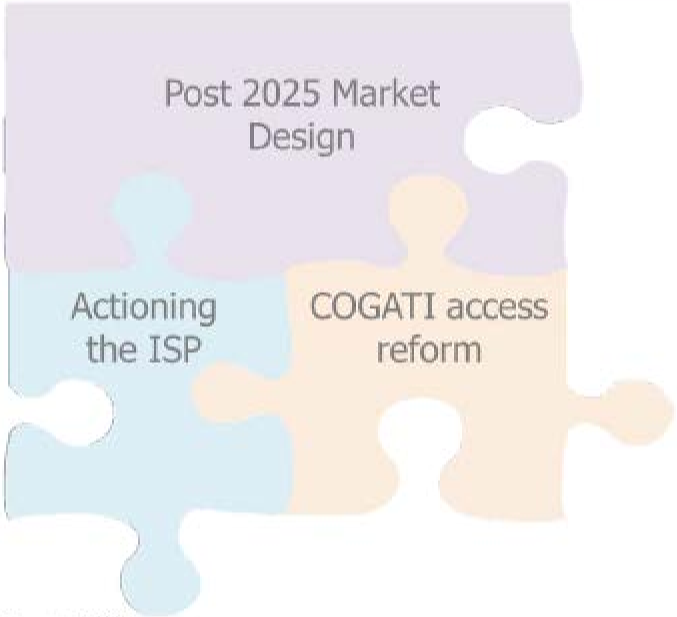
Integration with other reforms

- **Actioning the Integrated System Plan**: The ESB is working to action the ISP, which goes hand in hand with our proposed reforms:
    - ISP and related processes will establish the amount of financial transmission rights available for purchase
    - Subsequent sale of those financial transmission rights provides better information for transmission planning

- **Post 2025 Market Design**: The ESB is undertaking a project for COAG Energy Council on a long-term fit for purpose market framework to support reliability.
    - The proposed reforms also allow sufficient flexibility for different future market designs to be explored under the Post 2025 Market Design work.

- The AEMC is working closely with the ESB on these projects.

Figure 3.4: Integration of market reforms



Source: AEMC

Algebraic representation of the access model

- Current market settlement
  - Revenue = RRP x physical dispatch
- Current effective market settlement
  - Revenue = LMP x physical dispatch + (RRP — LMP) x physical dispatch
- Proposal under reform
  - Revenue = LMP x physical dispatch + (Locational price 1 — Locational price 2) x FTR quantity
- Solves two problems with current market
  - Market participants now settled at LMP, not RRP, a more efficient price signal
  - Market participants' spot market revenue is partially decoupled from physical dispatch, market participants able to manage the risk of congestion by acquiring FTRs. When congestion arises, this creates locational price differences and resulting FTR payments.

Dynamic regional pricing and financial transmission rights

Under the proposed model, large-scale generators and storage would receive a **locational marginal price** that more accurately reflects the cost of supplying electricity at their location on the network, accounting for both transmission congestion and losses.

Retailers would continue to pay a **regional price**.

Settlement residues accrue as a result of the difference between the price paid to generators at locational marginal prices, and the price charged to load at regional prices

Participants will be able to purchase **financial transmission rights** (FTRs).

These products will assist participants in managing the risks associated with network congestion and losses, since FTRs will pay out to participants the difference between local prices and the regional price.

The funds for the FTR payouts come from **settlement residues**.

We have developed a proposed access model containing detail of dynamic regional pricing and financial transmission rights

DRP and FTRs well established overseas

"Locational marginal pricing (LMP) is the electricity spot pricing model that serves as the benchmark for market design – the textbook ideal that should be the target for policy makers."

International Energy Agency, 2007

"Nodal pricing is crucial to ensuring that accurate economic evaluations of engineering decisions can be made."

Singapore Energy Market Authority, 2010

"Financial transmission rights are essential ingredients of efficient markets in wholesale electricity systems"

Prof. Bill Hogan, Harvard University, 2013

"LMP – should encourage short-term efficiency in the provision of wholesale energy and long-term efficiency by locating generation, demand response and/or transmission at the proper locations and times."

US Federal Energy Regulatory Commission, 2002

"Operating alongside the electricity hedge market, the FTR market helps to promote retail competition by encouraging retailers to compete for customers on a nationwide basis, as opposed to focusing primarily on regions close to where they own generation assets."

NZ Electricity Authority website

"The purpose of FTRs to serve as a congestion hedge has been well established."

US Federal Energy Regulatory Commission (FERC), 2017

Summary of key design features for proposed access model

Issue	Proposed Design Choice
What participants will face the local price?	• Large-scale (scheduled) generators and storage would be paid their local price, reflecting the cost of supply at their specific location • Retailers and so customers would still pay the regional price
What is the regional price?	• Ideally, it would be calculated as the volume weighted average of local prices.
How will participants manage the risk of congestion and losses?	• Large-scale (scheduled) generators and storage will be able to purchase financial transmission rights. • These will provide a financial payout when the local price differs from the regional price due to congestion and/or losses. • These rights will only pay out a positive amount.

Summary of key design features for proposed access model

Issue	Proposed Design Choice
What different types of rights can be purchased?	• Payout between: local price & regional price; and regional price & other regional price. • Payout can be continuous or time of use.
How long can they be purchased for?	• Quarterly periods, up to 4 years in advance.
What will the local prices reflect, and so what risks will the rights cover?	• All constraints in NEMDE. • Dynamically calculated loss factors.

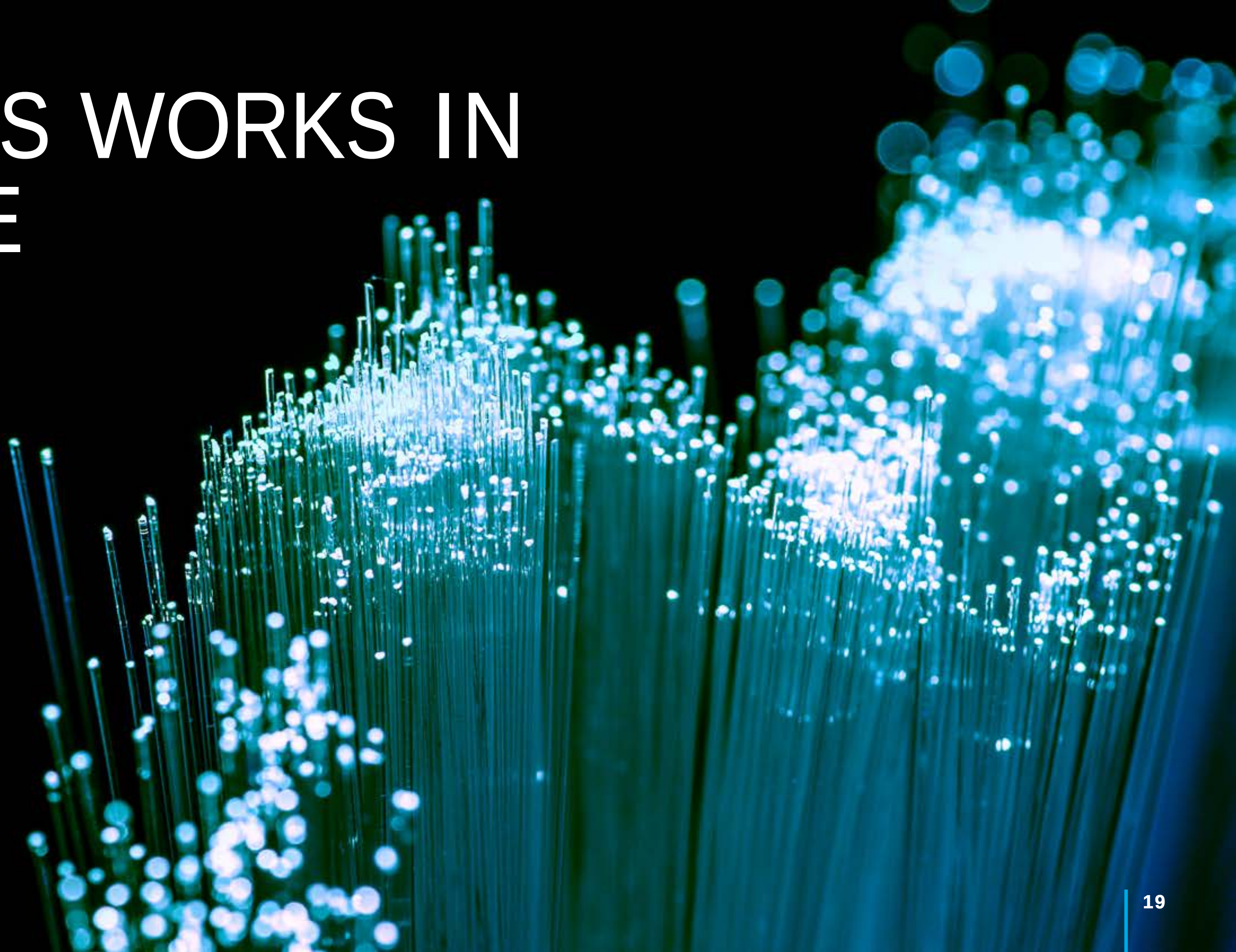
Summary of key design features for proposed access model

Issue	Proposed Design Choice
How can parties purchase the rights?	• AEMO would run an auction – with input from TNSPs – to determine how many rights can be sold. • Large-scale (scheduled) generators and storage would bid for these rights in an auction.
Who can purchase the rights?	• Any physical player
How transparent would the process be?	• AEMO would maintain a register of rights sold, and the sale price.

Summary of key design features for proposed access model

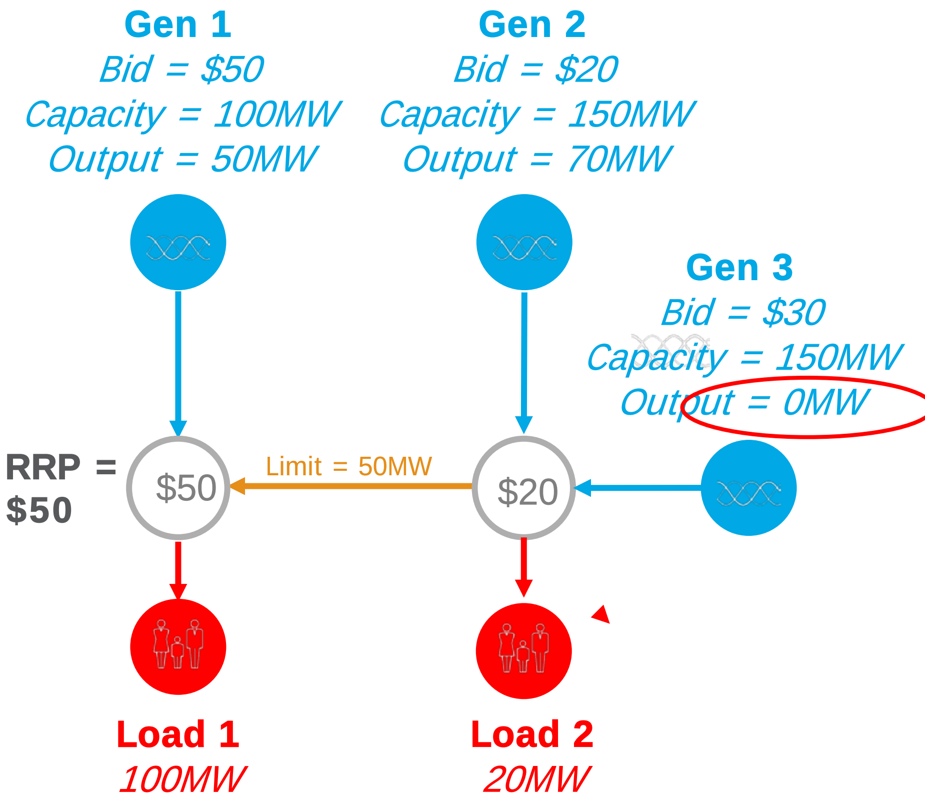
Issue	Proposed Design Choice
How are issues of market power dealt with?	• We do not envisage that market power will be increased. • However, if we do need a market power mitigate measure, then a cap on a generator’s offer would be applied if it was deemed to be pivotal.
Would there be grandfathering?	• There would be a transitional period where incumbent generators would be granted, rather than pay for, rights
When would it be implemented?	• 2022

HOW THIS WORKS IN PRACTICE



Current arrangements, with congestion

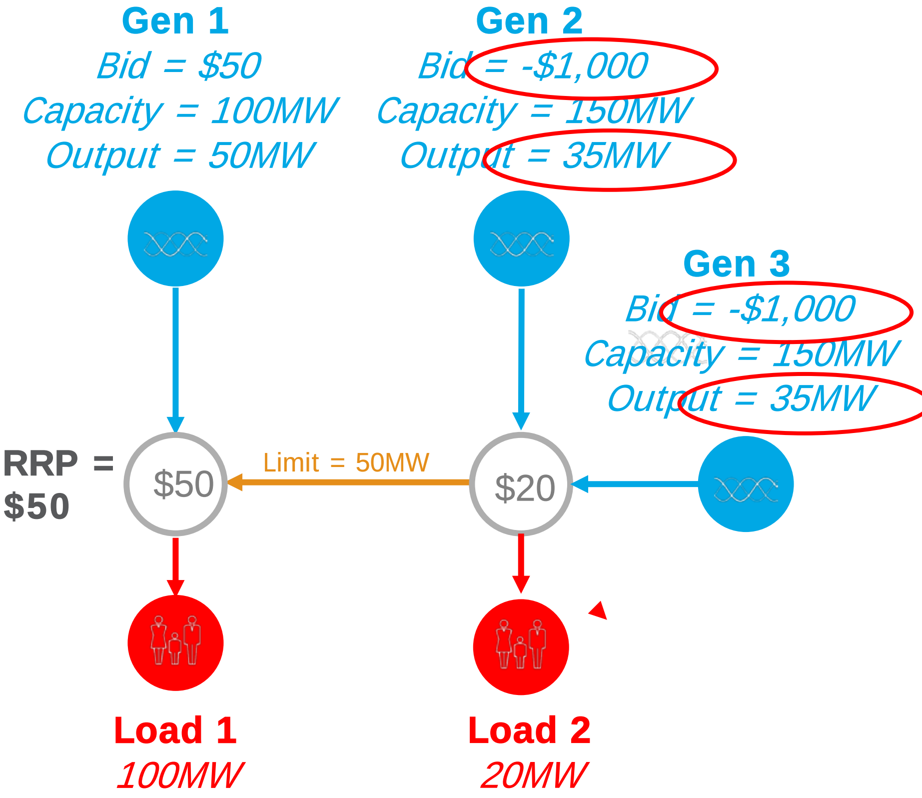
Participant	Energy settlement (RRP x dispatch quantity)
G1	-2,500
G2	-3,500
G3	0
L1	5,000
L2	1,000
Total	**0**



Excludes effects of losses.
Generators are scheduled, load is unscheduled.

Current arrangements, with race to floor bidding

Participant	Energy settlement (RRP x dispatch quantity)
G1	-2,500
G2	-1,750
G3	-1,750
L1	5,000
L2	1,000
Total	**0**



Excludes effects of losses.
Generators are scheduled, load is unscheduled.

Common misconception addressed

Common misconception addressed:
“Disorderly bidding” is a generic term for any type of bidding behaviour which is inconsistent with long term interest of consumers.

Incentives to disorderly bid arise due to, *for example*:

- Regional prices not equaling local prices
- 30 minute prices not equaling 5 minute prices.

These are 2 separate problems with 2 separate solutions. 5 minute settlement is intended to address the latter, COGATI the former.

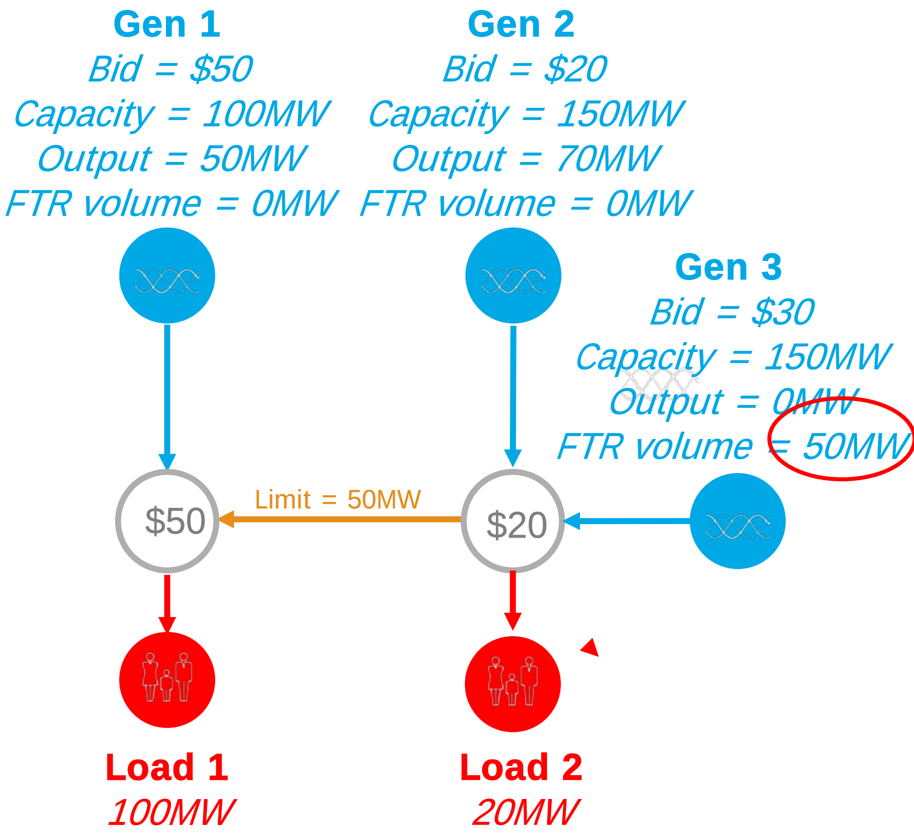
5 minute settlement was never a solution to the former, or vice versa.

Common misconception addressed:
While it is true that dispatch inefficiencies arising from race to the floor bidding behaviour will be minimal if all generators behind the constraint have the same short run costs (eg, zero), this ignores the effect of batteries.

Batteries do not have a short run cost of zero, and so existing incentives will result in inefficient dispatch/charging of batteries.

Arrangements under proposed access model

Participant	Energy settlement (LMP x dispatch quantity)	FTR settlement (price difference x FTR quantity)	Total settlement
G1	-2,500	0	-2,500
G2	-1,400	0	-1,400
G3	0	-1,500	-1,500
L1	What non-scheduled participants pay explained in subsequent slide		
L2			



Excludes effects of losses.
Generators are scheduled, load is unscheduled.

VWAP pricing

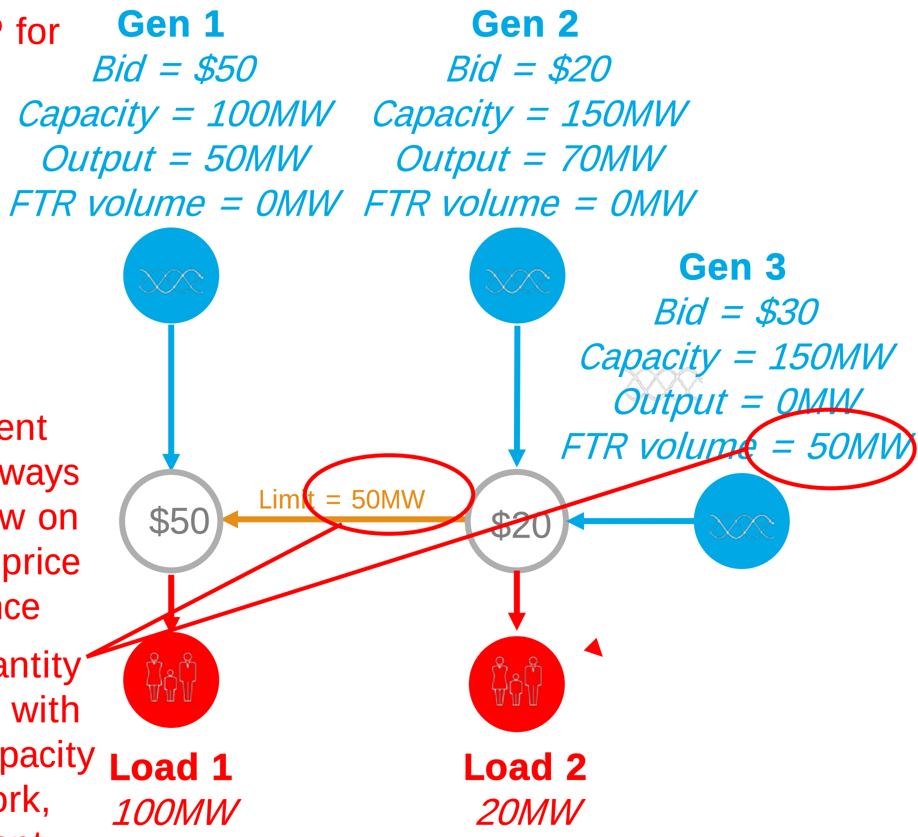
Energy settlement uses LMP for scheduled participants and VWAP for non-scheduled

Participant	Energy settlement	FTR settlement (price difference x FTR quantity)	Total settlement
G1	-2,500	0	-2,500
G2	-1,400	0	-1,400
G3	0	-1,500	-1,500
L1	4,500	0	4,500
L2	900	0	900
Total	**1,500**	**-1500**	**0**

Regional VWAP = $45
(100MW x $50 + 20MW x $20)/120MW

Settlement residue always equals flow on the line x price difference

If FTR quantity consistent with physical capacity of network, settlement balances

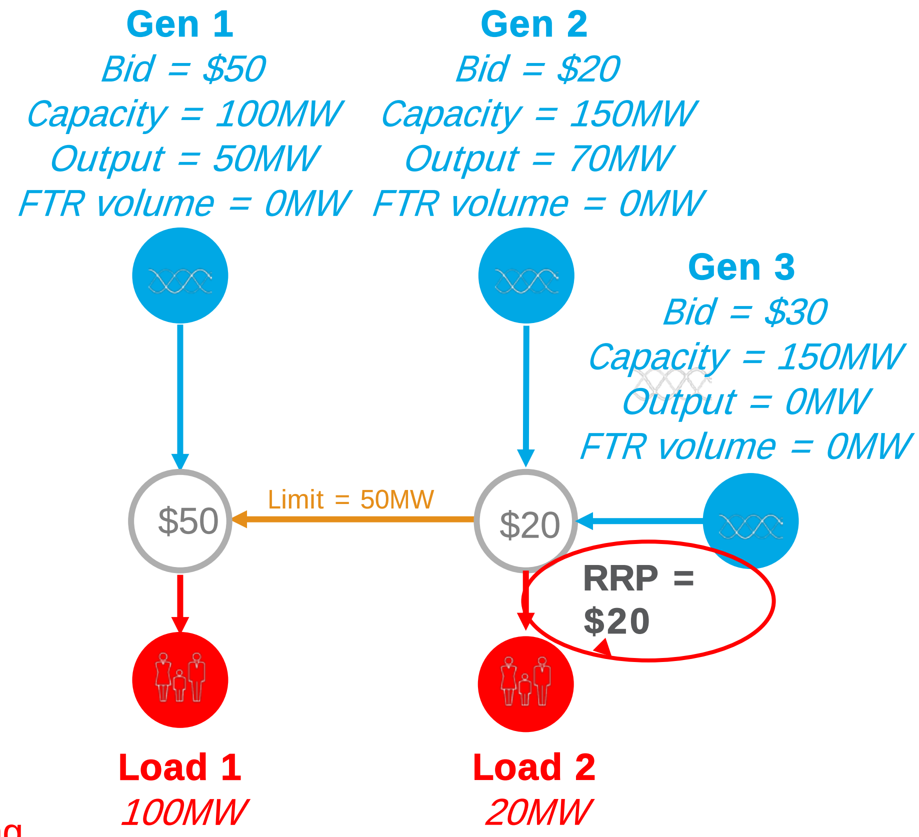


Excludes effects of losses.
Generators are scheduled, load is unscheduled.

Why ideally do we change from the RRP to VWAP?

Participant	Energy settlement	FTR settlement (price difference x FTR quantity)	Total settlement
G1	-2,500	0	-2,500
G2	-1,400	0	-1,400
G3	0	0	0
L1	2,000	0	2,000
L2	400	0	400
Total	**-1,500**	**0**	**-1,500**

If we use regional reference node pricing then we don't have enough income to settlement energy, let along FTRs

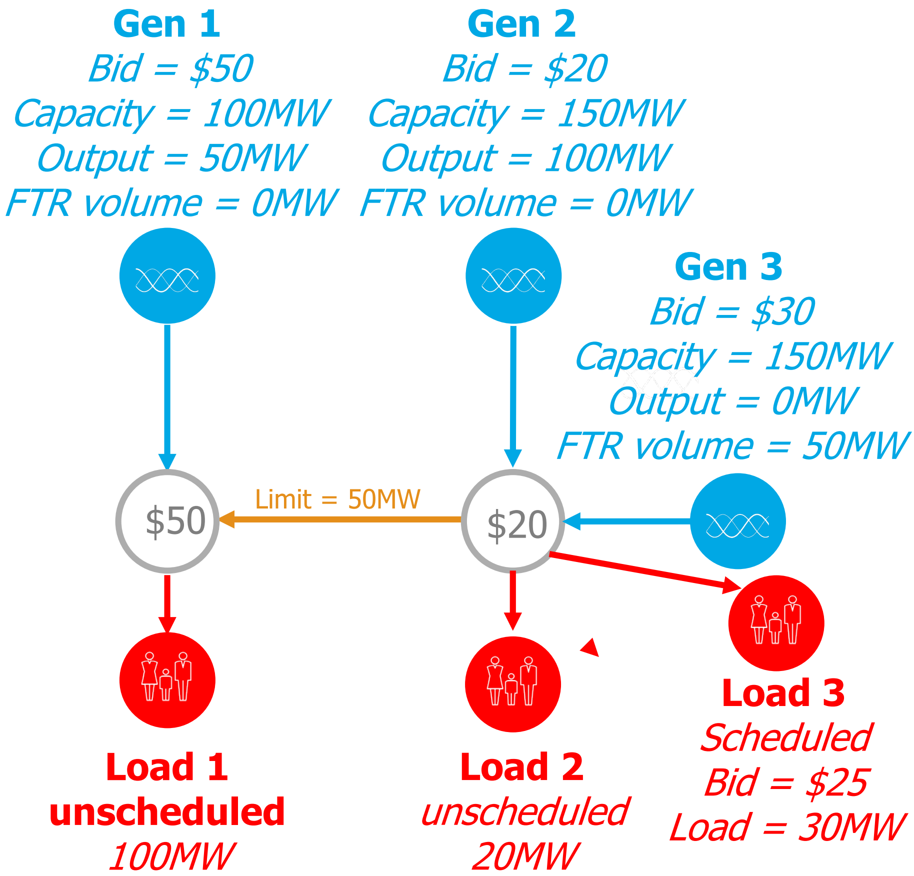


Excludes effects of losses.
Generators are scheduled, load is unscheduled.

VWAP pricing for non-scheduled participants; LMP pricing for scheduled participants

Participant	Energy settlement (LMP x dispatch quantity)	FTR settlement (price difference x FTR quantity)	Total settlement
G1	-2,500	0	-2,500
G2	-2,000	0	-2,000
G3	0	-1,500	-1,500
L1	4,500	0	4,500
L2	900	0	900
L3	30 x 20 =600	0	600
Total	**1,500**	**-1500**	**0**

Regional VWAP = $45
(100MW x $50 + 20MW x $20)/120MW



Excludes effects of losses.
Slide updated 28/10/2019 to correct mathematical errors

Link to commodity market

Revenue from spot market	= LMP x dispatch quantity	[1]
Revenue from FTR	= (VWAP – LMP) x FTR quantity	[2]
Revenue from swap contract	= (Strike price – VWAP) x swap quantity	[3]
Short run cost	= Short run marginal cost x dispatch quantity	[4]

Short run profit = [1] + [2] + [3] – [4]
= dispatch quantity x (LMP – SRMC)
+ FTR quantity x (VWAP – LMP)
+ Swap quantity x (Strike price – VWAP)

No constraints
VWAP = LMP
Dispatch quantity can equal contract quantity, so:

Short run profit = Swap quantity x (Strike price – SRMC)

Constraints bind
Dispatch quantity = 0 (due to constraint)
If FTR quantity = contract quantity, then:

Short run profit = Contract quantity x (Strike price – LMP)

But we know that SRMC ≥ LMP (or else dispatch quantity not zero, had the generator bid at SRMC), so short run profit *at least* as large as if there were no constraints.

Excludes effects of losses.

Common misconception addressed

Common misconception addressed:

LMP pricing does not introduce a new risk to the sector.

Instead, it makes the existing risk of congestion, which manifests in lower dispatch quantities, more transparent.

FTRs enable that risk to be hedged.

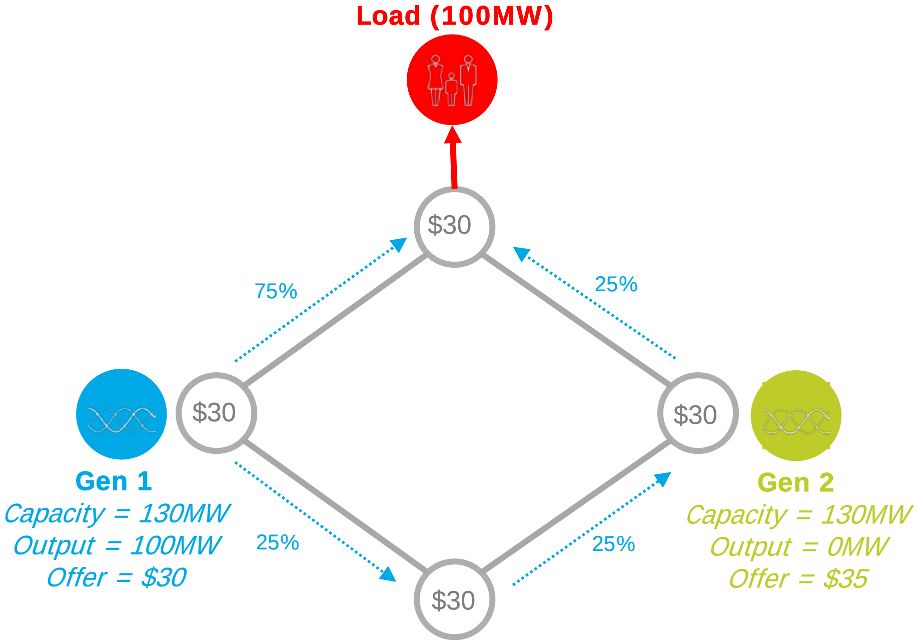
Common misconception addressed:
Introduction of the reforms is likely to increase not decrease contract market liquidity.

Currently, generator’s that have a contract risk being “short” as a consequence of transmission constraints. They reduce their contract quantity accordingly, to reduce the downside risk.

Inter- and intra-regional FTRs provide generators the ability to manage this risk, and hence offer more contracts.

Dynamic regional pricing – meshed network without constraints

Participant	Energy settlement (LMP x dispatch quantity)	FTR settlement (price difference x FTR quantity)	Total settlement
G1	-3,000	0	-3,000
G2	0	0	0
L1	3,000	0	3,000
Total	**0**	**0**	**0**



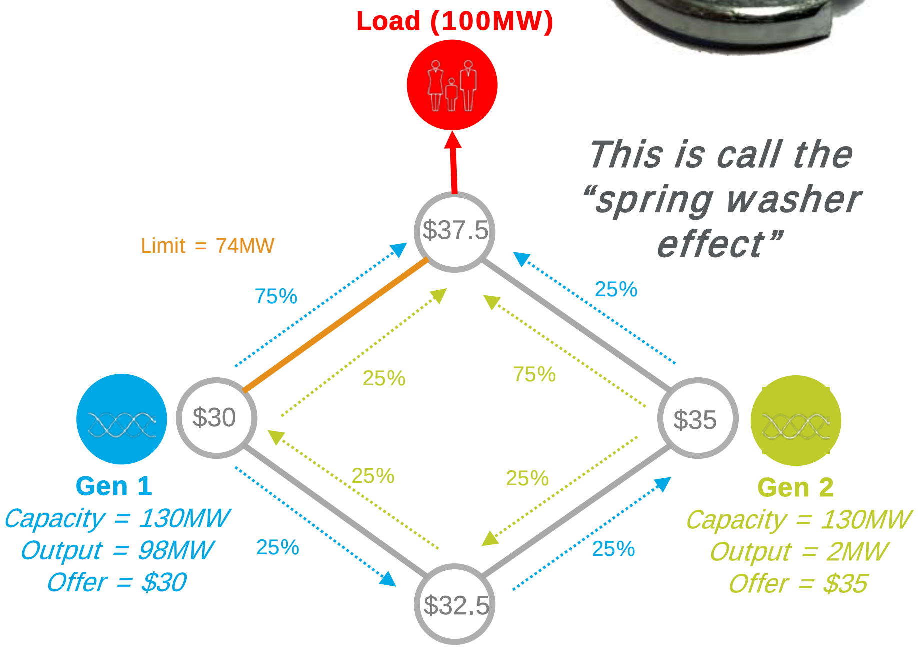
Assumes all lines have equal impedance.
Excludes effects of losses.

Dynamic regional pricing – meshed network with constraints

Participant	Energy settlement (LMP x dispatch quantity)	FTR settlement (price difference x FTR quantity)	Total settlement
G1	-2,940	0	-2,940
G2	-70	0	-70
L1	3,750	0	3,750
Total	**740**	**0**	**740**

Settlement residue equal to flow on each of the lines, multiplied the price differences between the nodes

This is call the "spring washer effect"

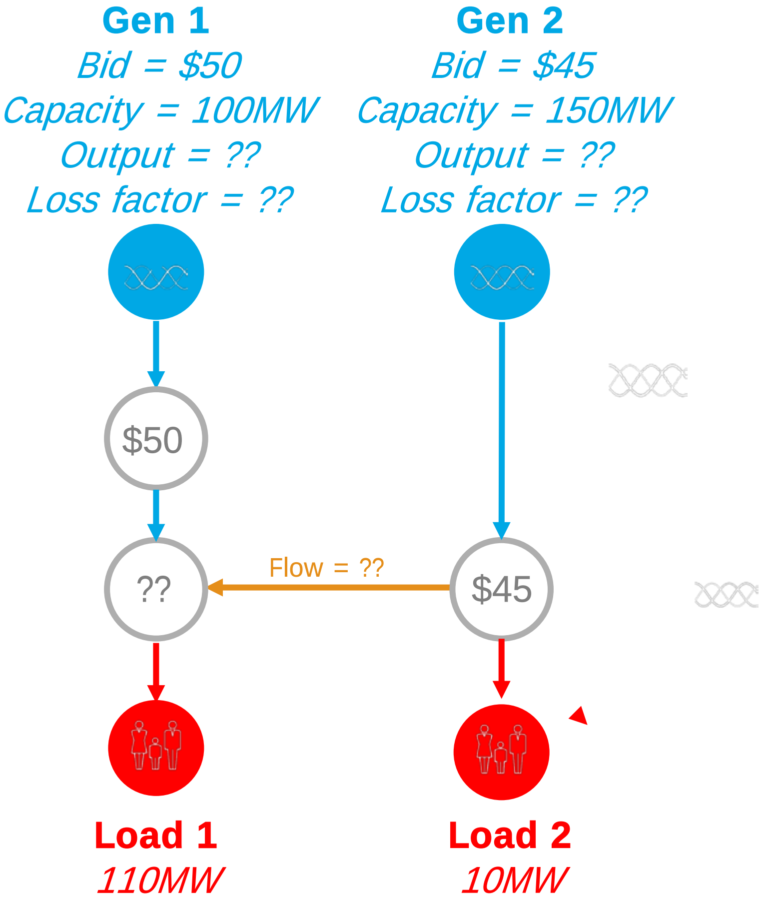


Assumes all lines have equal impedance.
Excludes effects of losses.

Marginal loss factors and dispatch efficiency

Participant	Static MLF	Loss adjusted bid	Output
G1	0.9	50 / 0.9 = 55.6	0
G2	0.85	45 / 0.85 = 52.9	120
LMP at load 1 = $52.9, flow across orange line is 110MW			

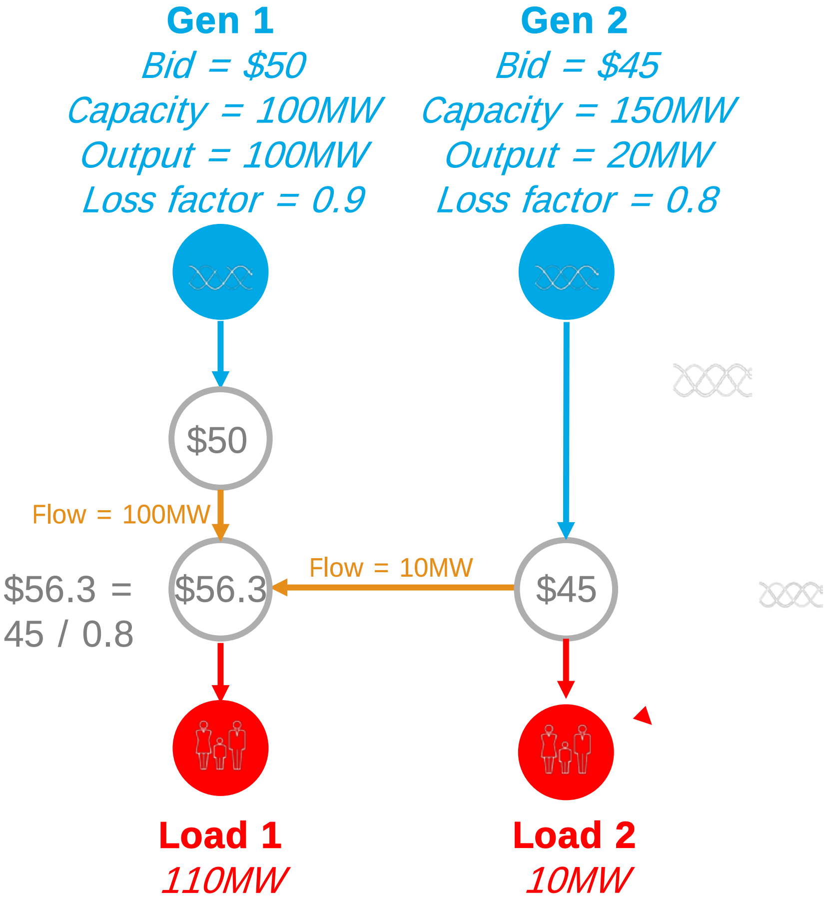
Participant	Actual MLF	Loss adjusted bid	Output
G1	0.9	50 / 0.9 = 55.6	100
G2	0.8	45 / 0.8 = 56.3	20
LMP at load 1 = $56.3, flow across orange line is 10MW			



DRP and dynamic marginal loss factors

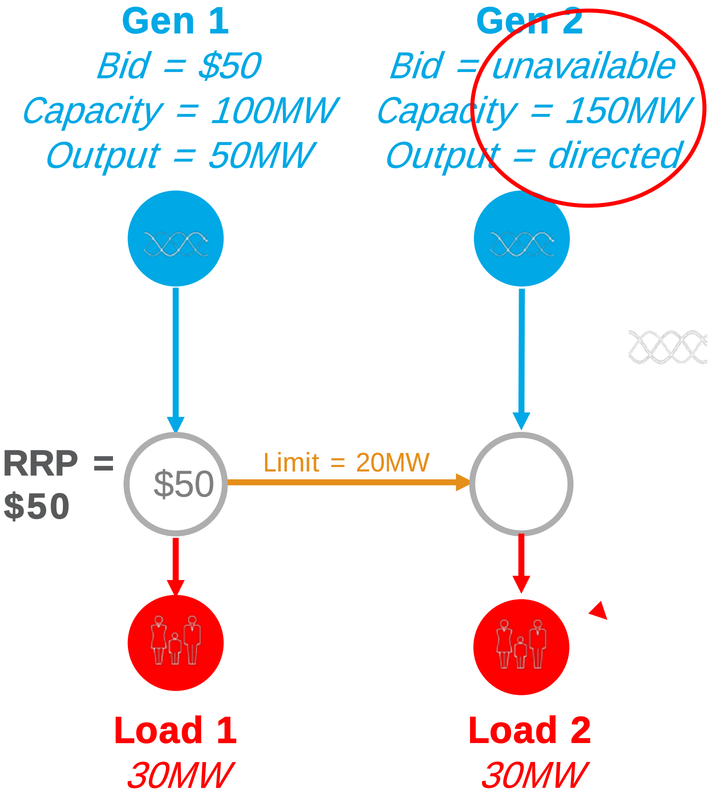
Participant	Energy settlement (LMP x dispatch quantity)	FTR settlement (price difference x FTR quantity)	Total settlement
G1	-5,000	0	-5,000
G2	-900	0	-900
L1	6,084	0	6,084
L2	553	0	553
Total	**738**	**0**	**738**

Regional VWAP = $55.4
(110MW x $56.3 + 10MW x $45)/120MW
Reflects MLFs in local prices at unscheduled participant nodes



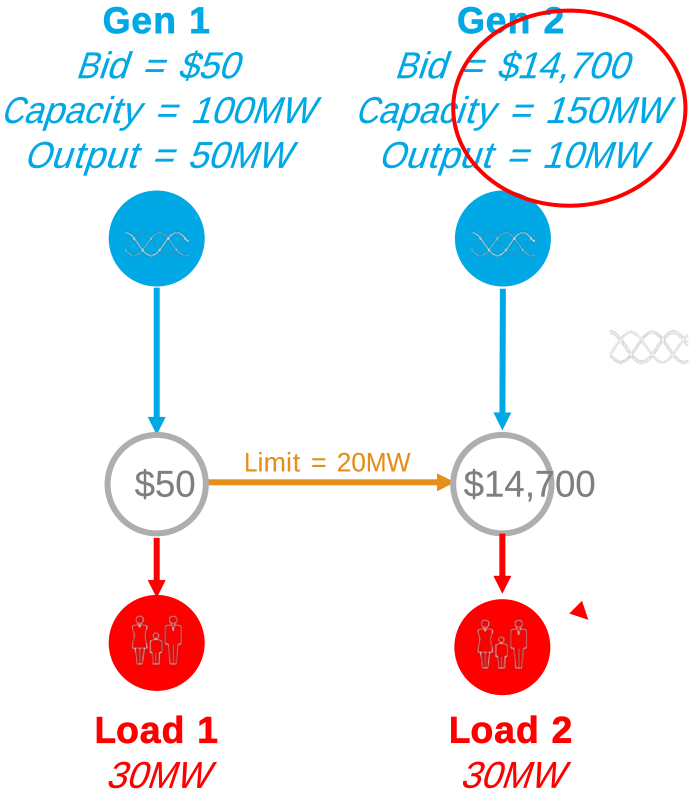
Generators are scheduled, load is unscheduled

Market power in a load pocket – current arrangements



Excludes effects of losses
Generators are scheduled, load is unscheduled

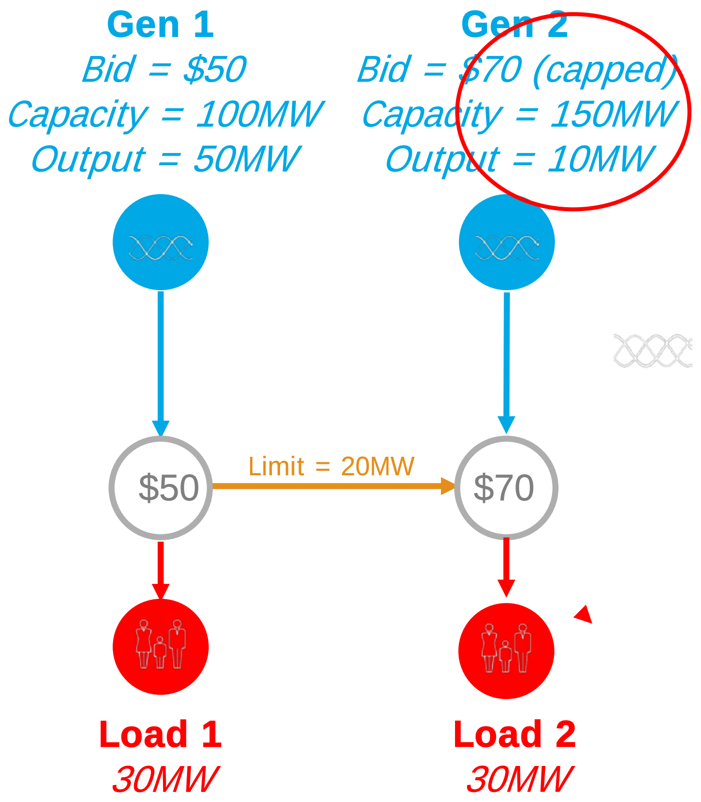
Market power in a load pocket – dynamic regional pricing



Regional VWAP = $7,392
(30MW x $50 + 30MW x $14,700)/60MW

Excludes effects of losses
Generators are scheduled, load is unscheduled

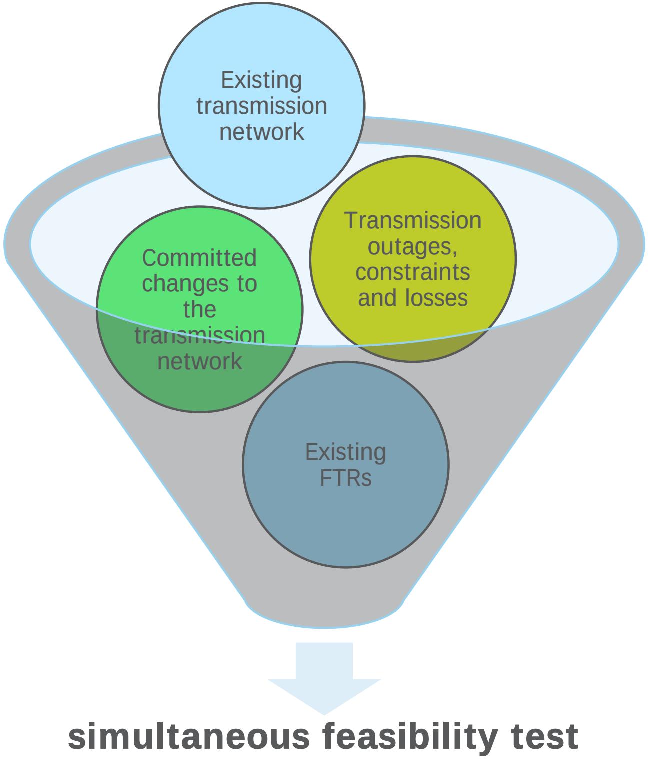
Market power in a load pocket – under dynamic regional pricing, w bid cap



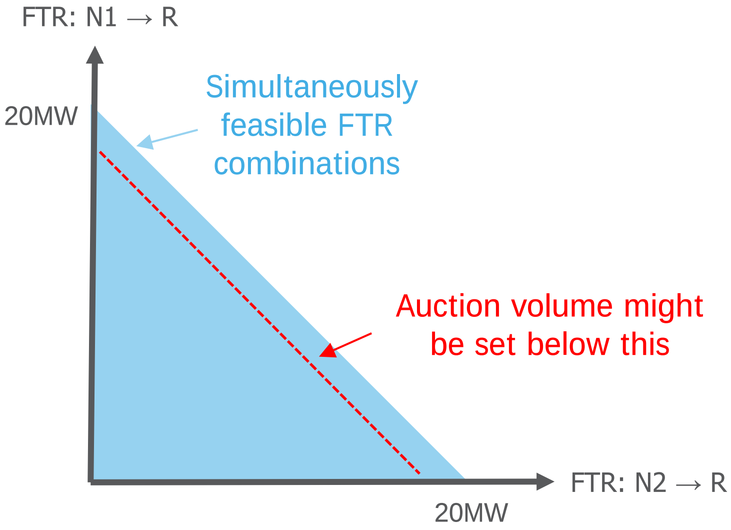
Regional VWAP = $60
(30MW x $50 + 30MW x $70)/60MW

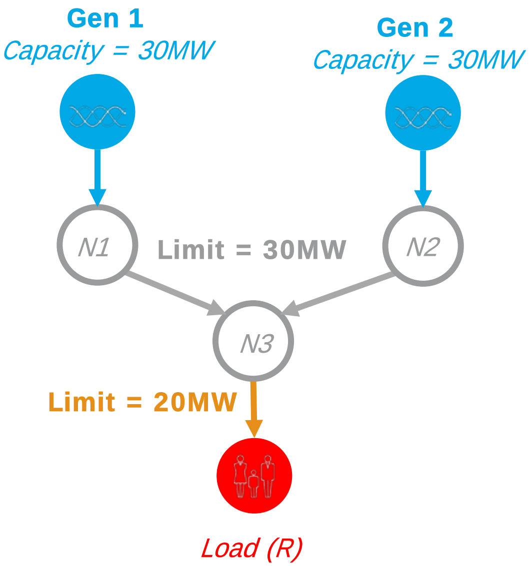
Excludes effects of losses
Generators are scheduled, load is unscheduled

FTR auctions – simultaneous feasibility auction

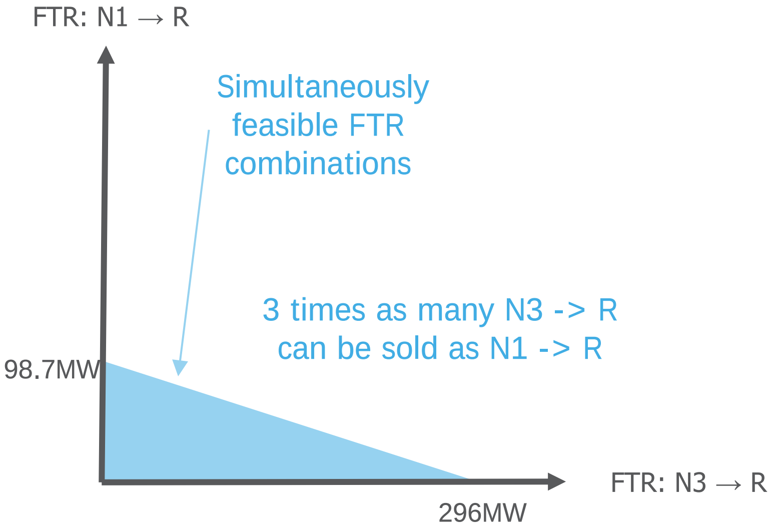


Simultaneous feasibility – simple example

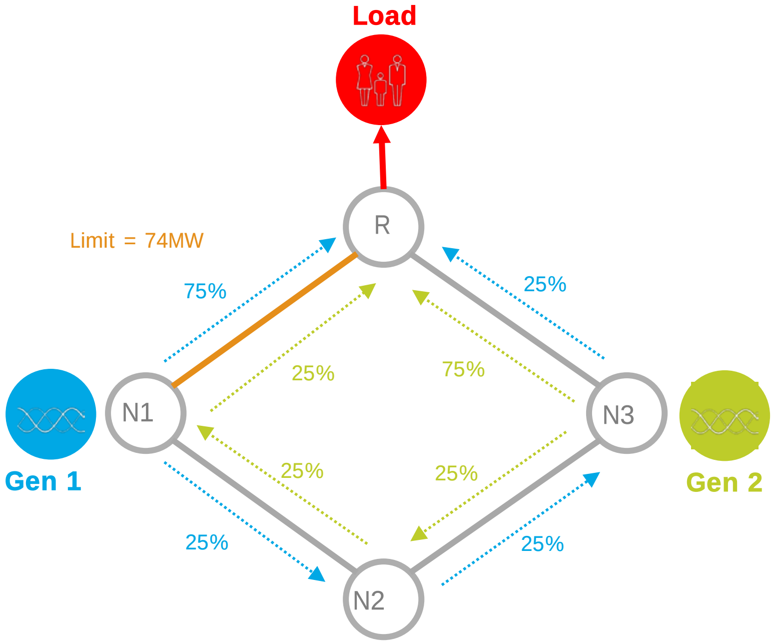




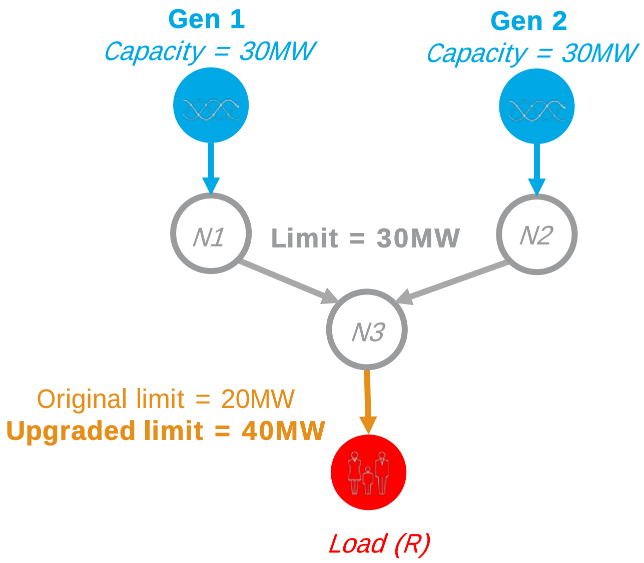
Simultaneous feasibility – meshed network example

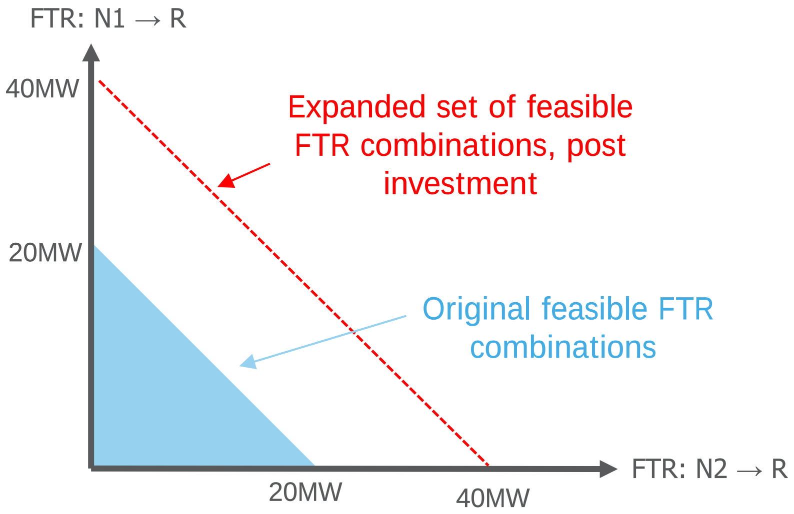


98.7MW = 74 / 0.75
296MW = 74 / 0.25



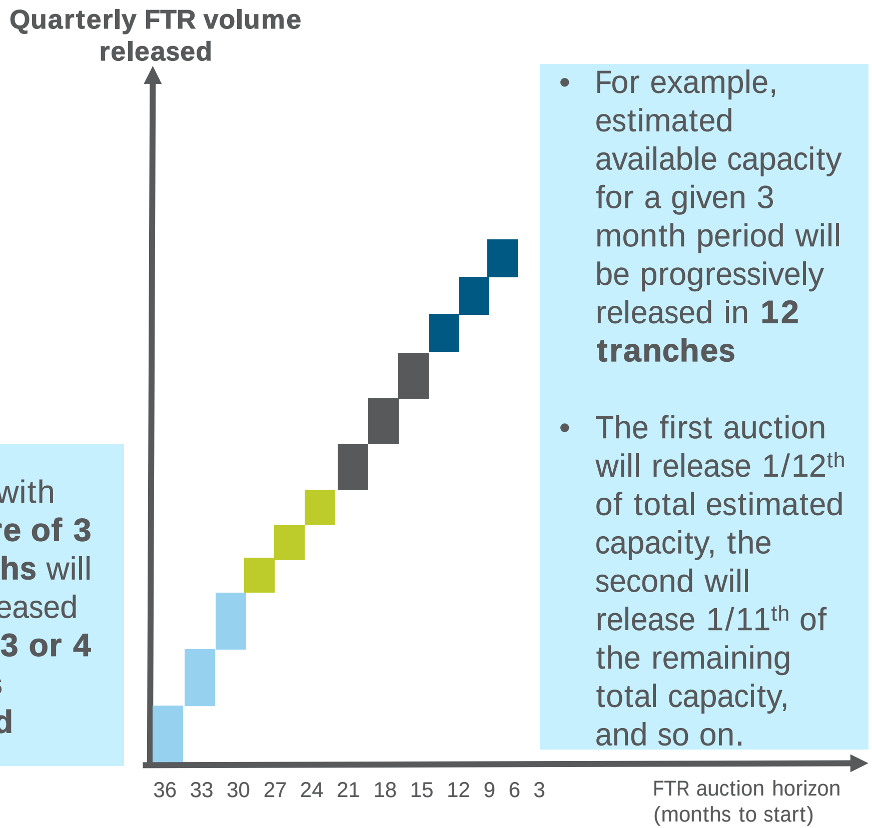
Impact of network investment



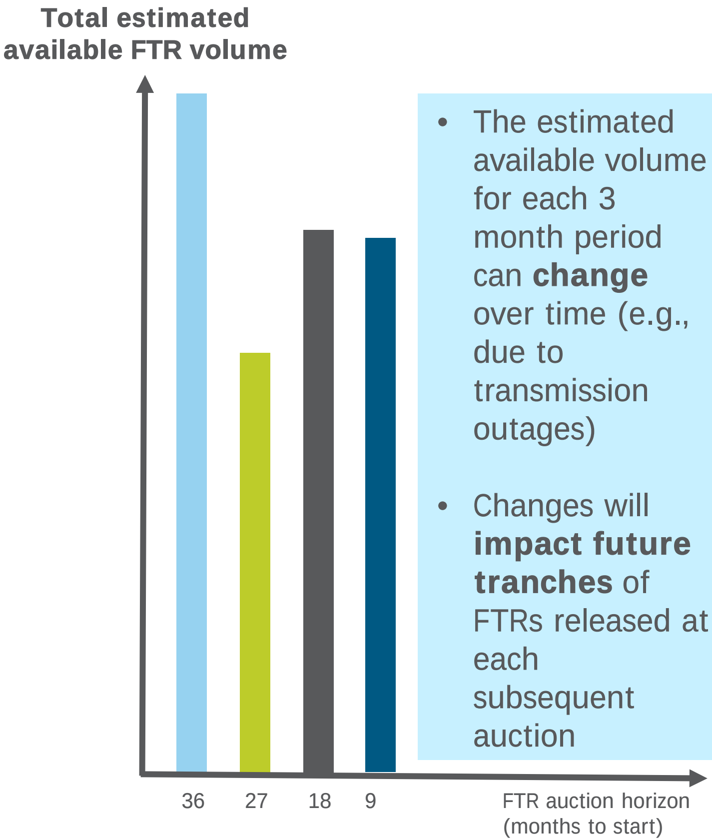


Progressive release of FTR capacity

- FTRs with **tenure of 3 months** will be released up to **3 or 4 years ahead**



- For example, estimated available capacity for a given 3 month period will be progressively released in **12 tranches**
- The first auction will release 1/12th of total estimated capacity, the second will release 1/11th of the remaining total capacity, and so on.



- The estimated available volume for each 3 month period can **change** over time (e.g., due to transmission outages)
- Changes will **impact future tranches** of FTRs released at each subsequent auction

FTR auctions – types of products

FTRs would be **options**, that only ever result in a positive payment. **Swaps** – that can result in a liability – would not be offered initially. They could be introduced later if valued by market participants.

FTRs would allow market participants to hedge price differences between **any local price and any regional price** and between **any two regional prices**.

FTRs would be both **continuous hedges** (active at all times of the day) and **time of use hedges** (active only during specific pre-defined time periods).

Product choice aims to achieve a balance between **complexity** and matching **market participants' hedging requirements**

FTR options and swaps

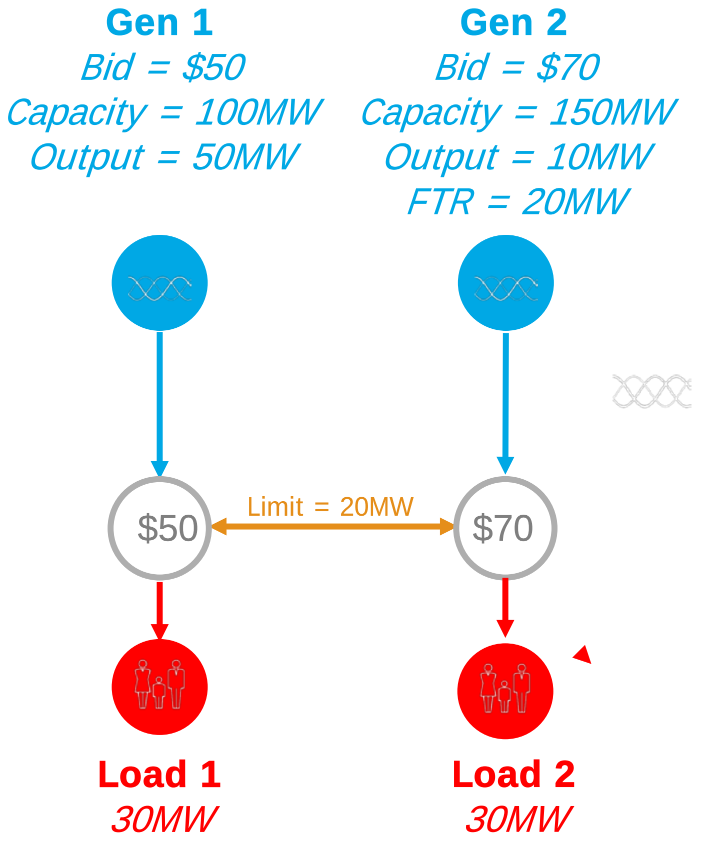
Regional VWAP = $60
(30MW x $50 + 30MW x $70)/60MW

FTR settlement (option)

Generator 2	= max(0,(VWAP- LMP)) x FTR volume = max(0, -10) x 20MW **= $0**

FTR settlement (swap)

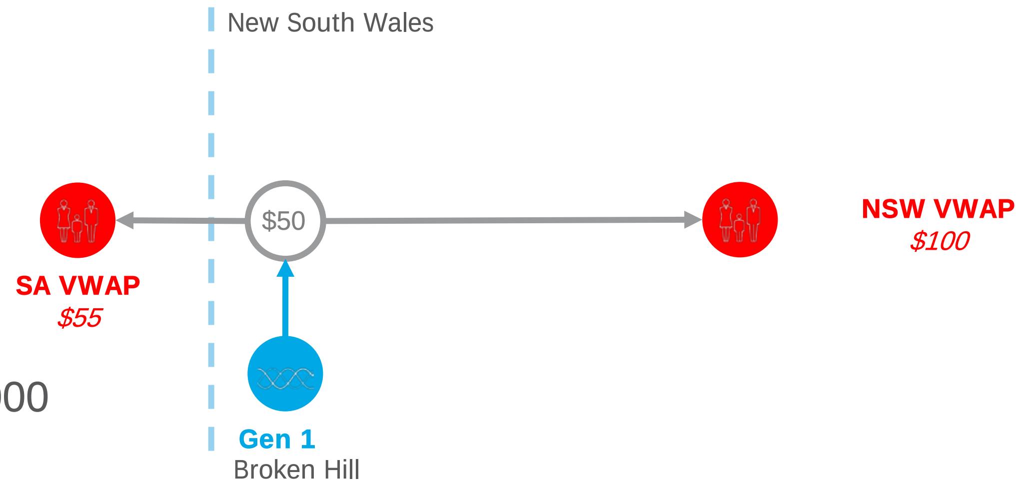
Generator 2	= (VWAP - LMP) x FTR volume = -20 x 10MW **= -$200**



FTR coverage – any local price to any regional price

- Generator 1 has:
  - 100MW FTR between its local price and the SA VWAP
  - 100MW swap settled against the SA VWAP, at a strike price of $60.

- It generates 100MW



Spot energy settlement = 50 x 100 = 5,000

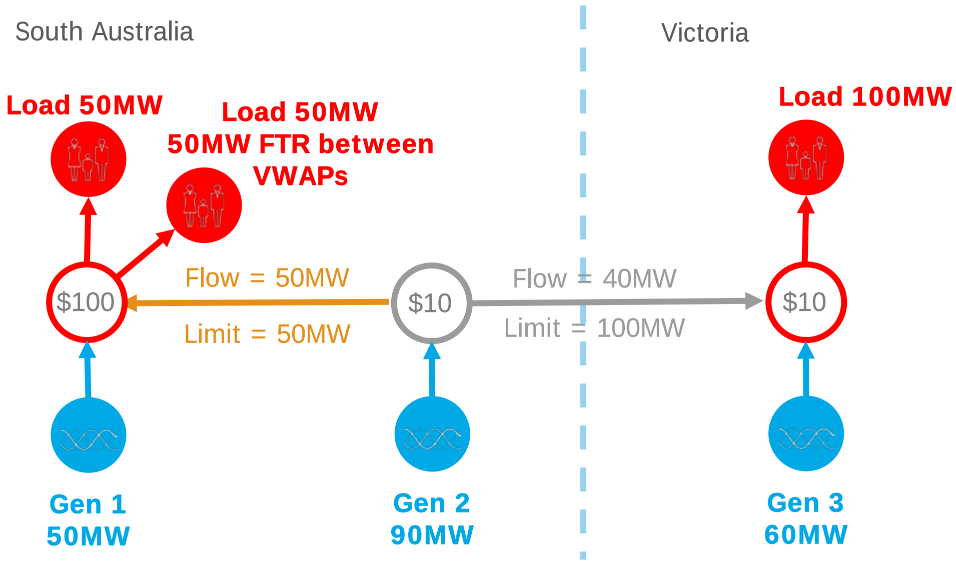
FTR settlement = (55 – 50) x 100 = 500

Contract settlement = (60 – 55) x 100 = 500

Total settlement = 6,000 (which is equal to 100 x 60)

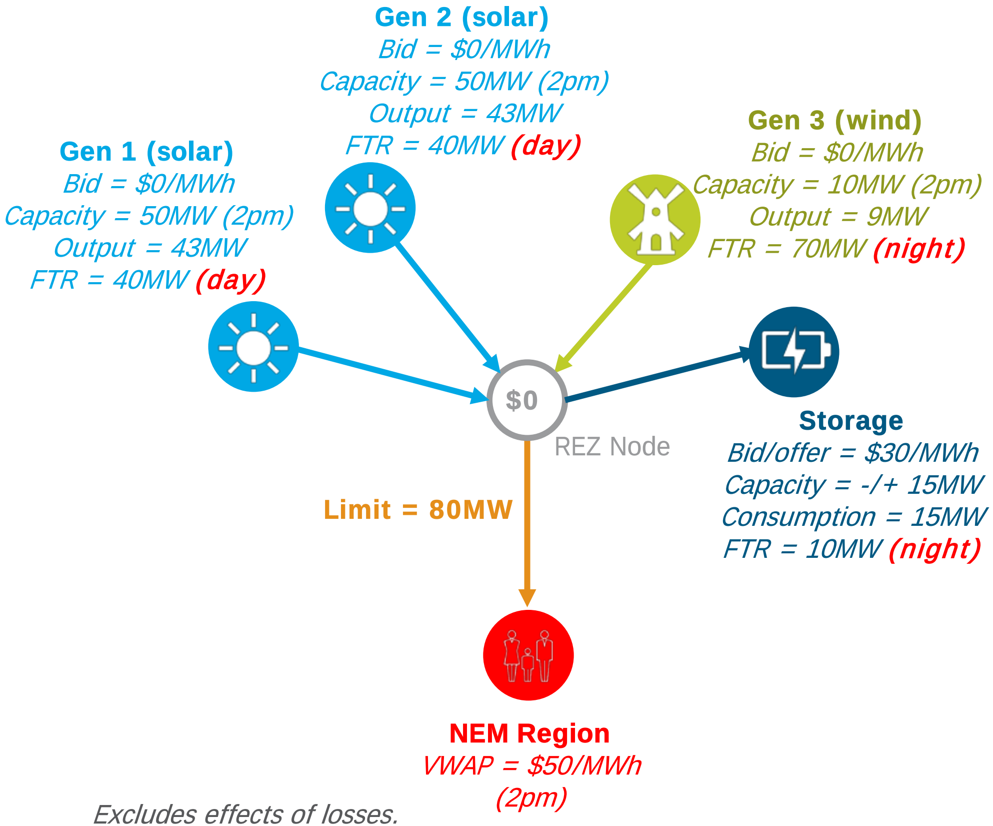
FTR coverage - any two regional prices

Participant	Energy settlement (LMP x dispatch quantity)	FTR settlement (price difference x FTR quantity)	Total settlement
G1	-5,000	0	-5,000
G2	-900	0	-900
G3	-600	0	-600
Load SA1	5,000	0	5,000
Load SA2	5,000	-4,500	500
Load Vic	1,000	0	1,000
Total	**4,500**	**-4,500**	**0**



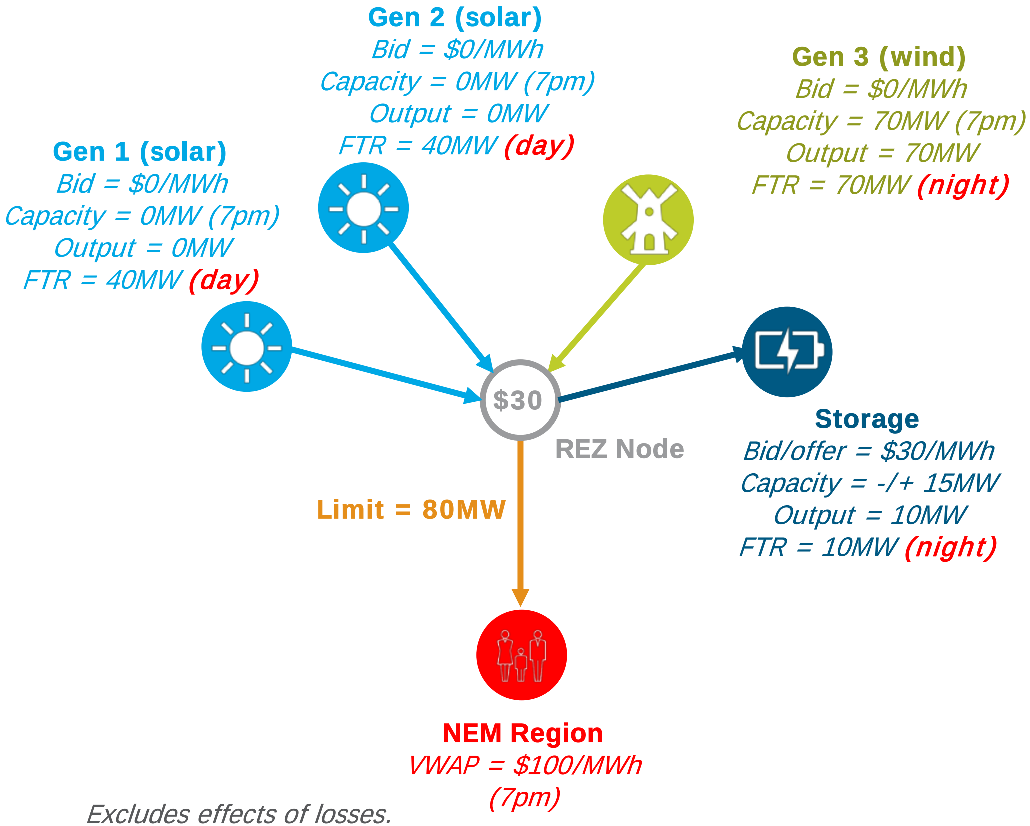
Excludes effects of losses.
Generators are scheduled, load is unscheduled.

Use of time-of-use FTRs in a REZ (day-time, 2pm)



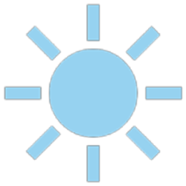
Excludes effects of losses.
Generators are scheduled, load is unscheduled.

Use of time-of-use FTRs in a REZ (night-time, 7pm)



Excludes effects of losses.
Generators are scheduled, load is unscheduled.

Time-of-use FTR settlement



2pm
LMP = $0
VWAP = $50

Participant	Dispatch	Spot revenue	Day-time FTR volume	FTR revenue
Gen 1 (solar)	43MW	$0	40MW	-$2,000
Gen 2 (solar)	43MW	$0	40MW	-$2,000
Gen 3 (wind)	9MW	$0	0MW	$0
Storage	-15MW (charging)	$0 (payment)	0MW	$0

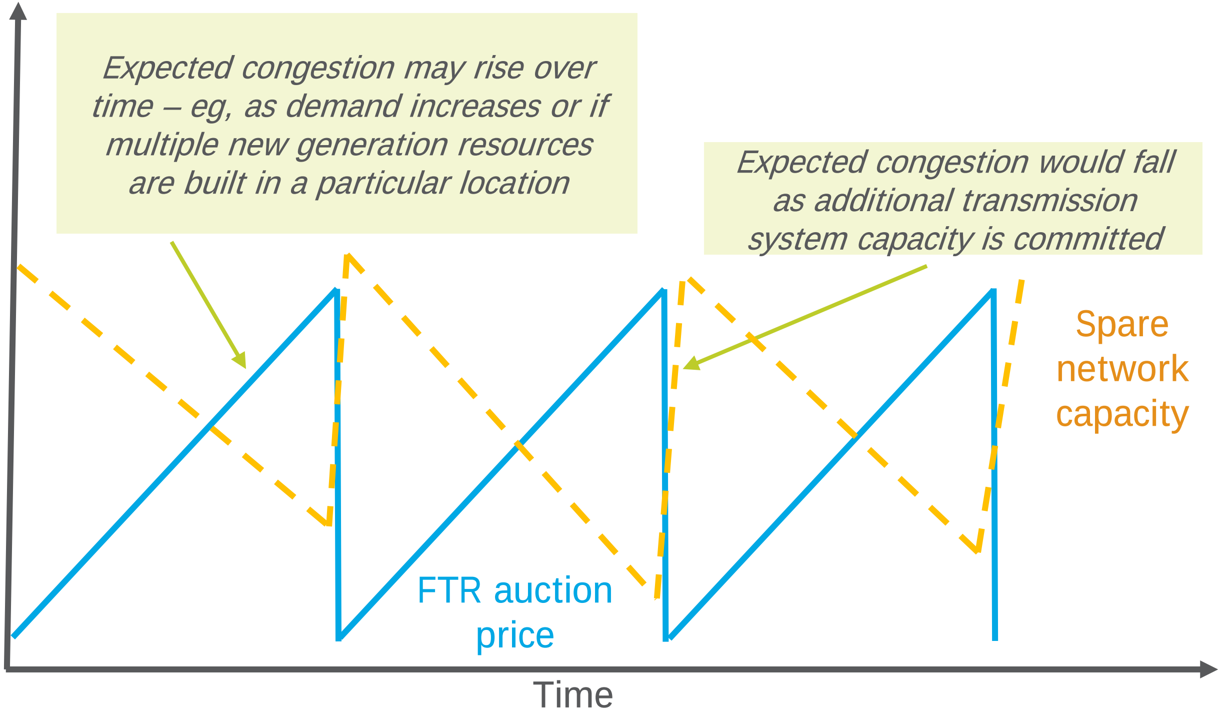
7pm
LMP = $30
VWAP = $100

Participant	Dispatch	Spot revenue	Night-time FTR volume	FTR revenue
Gen 1 (solar)	0MW	$0	0MW	$0
Gen 2 (solar)	0MW	$0	0MW	$0
Gen 3 (wind)	70MW	-$2,100	70MW	-$4,900
Storage	10MW (exporting)	-$300 (revenue)	10MW	-$700

Drivers of FTR auction outcomes

Factor	Impact
Expected congestion	Participants will be willing to pay more for an FTR for locations and times when expected congestion risk (expected FTR payout) is higher.
Contract positions	Participant demand for FTRs may be influenced by their contract position and the allocation of congestion risk in their contracts.
Technology type	Different generation technologies might expect their maximum preferred output to occur at different times (for example, during daylight hours for a solar farm). The mix of generators in particular parts of the network may therefore influence competition for particular FTR products.
Outages	Both scheduled loads and semi-/scheduled generators might consider planned outages, when an FTR may not be needed.
Number of participants	Auction prices could be expected to be higher if there are more participants bidding for particular FTRs.
Other risk management options	Demand for FTRs could be influenced by the cost and availability of other options to manage congestion risk (e.g., vertical integration, physical location)

Drivers of FTR auction outcomes



IMPACT ANALYSIS

Objectives of impact analysis

Stakeholders in response to the **June 2019 directions paper** suggested some form of quantitative analysis should be undertaken on the proposed model. Key objectives include:

- An evaluation of the **costs and benefits** of the proposed reform and whether it is likely to promote the NEO.
- Provide evidence to inform **specific design decisions.**
- Demonstrate the **distributional impacts**.
- **Communicate** what the reforms will look like in practice.

Proposed approach

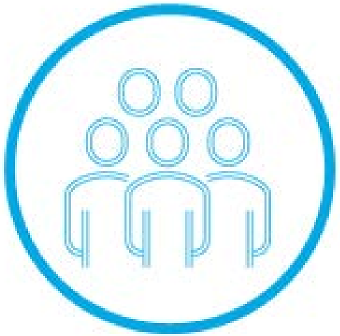
Category	Nature of task	By December 2019	By Mid-2020
1. Costs of reform	Implementation and ongoing costs	Comparable models	Survey of market participants, AEMO, AER
2. Benefits of reform	Benefits of reform	Comparable models	
	Risk management	WACC benefit	Survey of generators
	Operating incentives	Race to floor review	Forward modeling cost of race to the floor bids
	Dispatch efficiency	Benefits of dynamic loss factors	
	Locational incentives to invest	Historic costs of congestion - size of prize	
3. Policy Design	Market power	Zonal study of network - market power potential	
	Settlement residue to back FTRs		Simultaneous feasibility study - payout for FTRs
	Effect of VWAP pricing	TBD	TBD
4. Distributional impacts	Parties likely to benefit more or less		Distributional impacts, informed by 1 and 2
5. Communication	Simplified model of operation		Paper trial, 10 nodes

Cost of implementing proposed model

Costs for industry and market bodies take two forms:

- **Implementation costs**
- **Ongoing costs**

We propose to assess costs in two stages:



First stage: Research into cost of comparable reforms overseas, and revisit costing exercises in the NEM for comparable reforms.

Second stage: Survey of market participants and market bodies to understand implementation and ongoing costs. To be conducted later in the reform process, when the proposed model is more advanced and responses to the survey can consider these more detailed proposals.

Benefits of reform

Benefits of reform

- Research into comparable models (Dec 2019)

Risk management

- Improved investment certainty (Dec 2019)
- Survey generators and developers on the impact of FTRs on risk management (Mid-2020)

Improved operating incentives

- Race to floor bidding research (Dec 2019)
- Forward modeling cost of race to floor bidding (Mid-2020)

Dispatch efficiency

- Initial estimate of benefits of dynamic loss factors (Dec 2019)

Locational Incentives for investment

- Initial estimate of historic cost of congestion (Dec 2019)

Benefits are harder to model than costs

Policy design

Modelling of the proposed model could inform **three key areas** of policy design.

Market power

- Study of the network to determine the share held by any one generator in each zone, and potential market power issues that might arise (Mid-2020).

Revenue adequacy of FTRs

- feasibility study of simultaneous FTRs across key shared transmission assets in the NEM (Mid-2020).

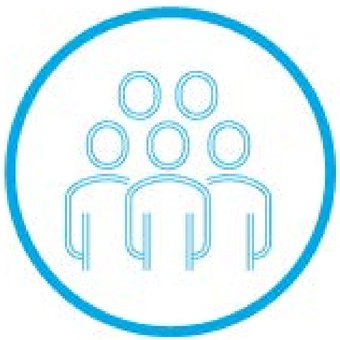
The effect of VWAP pricing

- Modelling VWAP would involve a full nodal model which the Commission does not plan to conduct at the current time.

Distributional impacts and a trial model

DISTRIBUTIONAL IMPACTS

Assessment of the broad categories of the market that are expected to benefit from the model, and those that are expected to be worse off.



TRIAL MODEL

Paper trial of the proposed model, for example using **10 nodes** over a limited timeframe. This will help demonstrate how the model will work in practice.

A basic simulated network will be constructed, providing simulated local prices and FTRs.

Stakeholder feedback on modelling

- Some stakeholders are in favour of **one cost-benefit exercise**.
- We have not identified an appropriate approach that would be robust

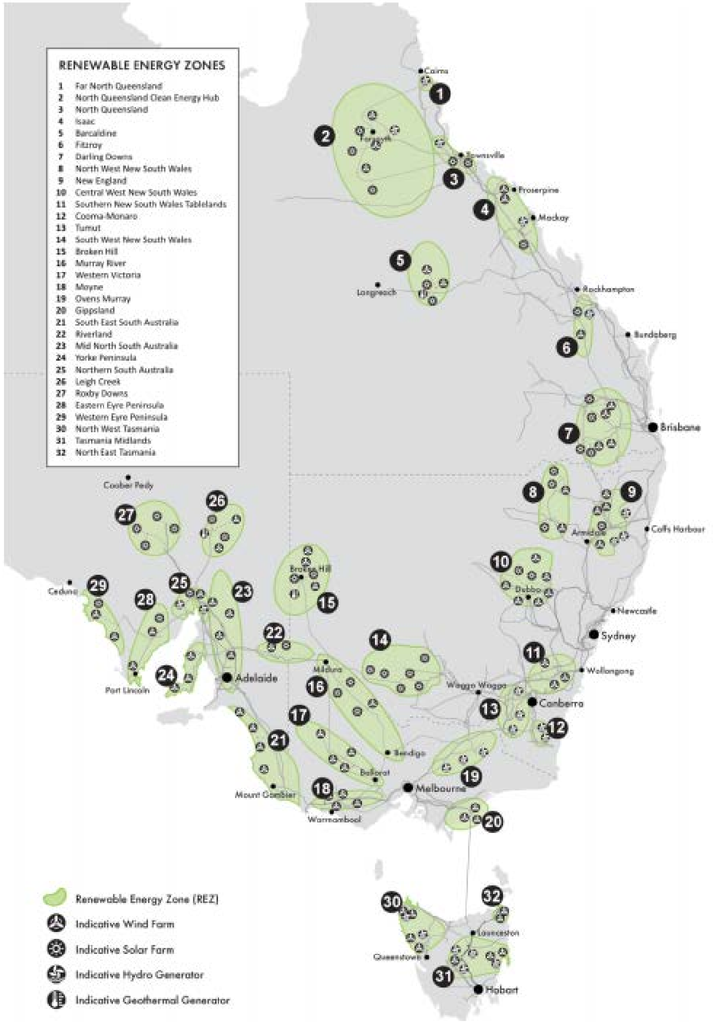
Model	Attributes	Positives	Negatives
Agent Based	Individual actions of profit maximizing agents	Models incentives and distributional impacts	➢ High costs. ➢ Highly uncertain to assume bidding strategies. ➢ Does not cover all modelling requirements (risk management)
Central Planner	Minimizes system costs to meet an objective (for example reliability)		➢ High costs. ➢ No account of bidding ➢ Does not model benefits of more efficient price signals for operations and investment ➢ Fails to model risk and impact on generator risk management and investment ➢ Assumes cost increases it seeks to determine
General Equilibrium	Macroeconomic model of the economy as a whole		➢ Changes in electricity sector are an input to the model. ➢ Assumes answer it seeks to find ➢ Fails to address policy design issues

RENEWABLE ENERGY ZONES

Need for renewable energy zones

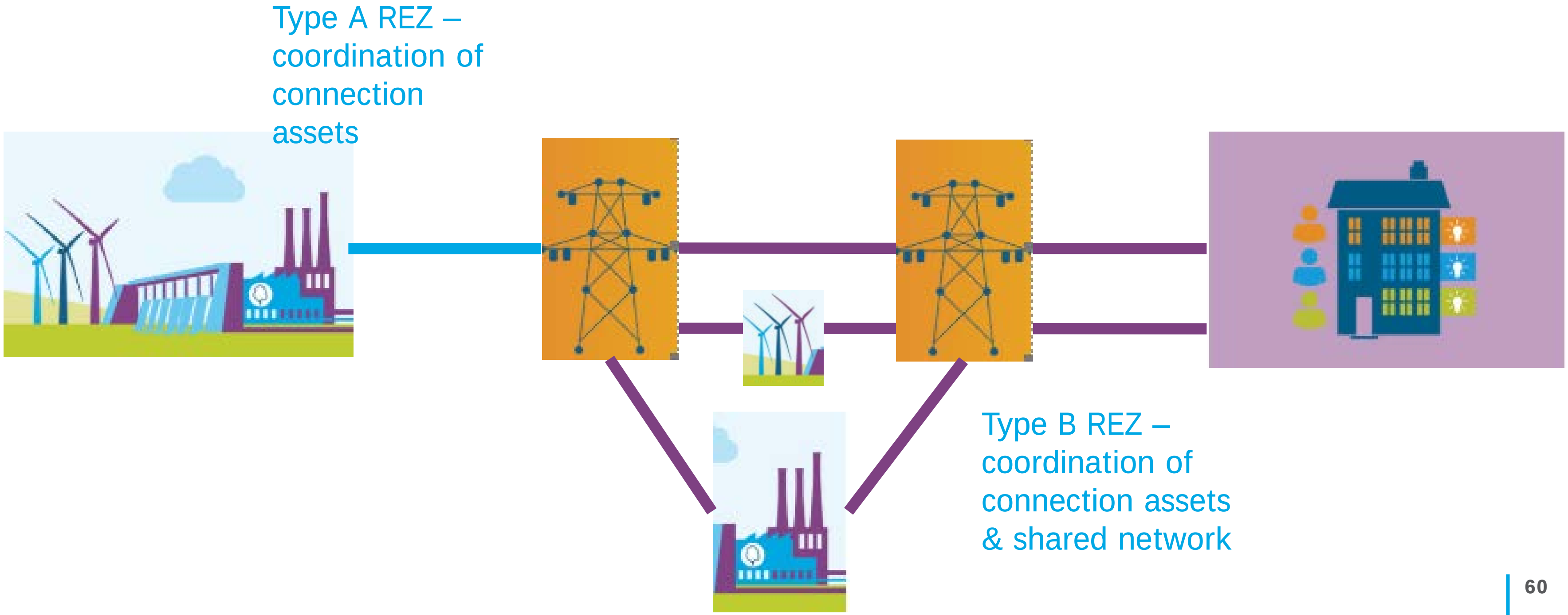
Renewable energy zones are areas with ***high resource potential*** *where* ***better coordination*** *can enable the connection and dispatch of generators at a* ***lower cost****.*

Figure 10 REZ candidates



What is a REZ?

The concept of a ‘renewable energy zone’ is not defined in the existing regulatory framework, and is used by different parties to describe different ideas and concepts, depending on what a particular party wants to achieve and do.



Ways in which REZs can currently be facilitated

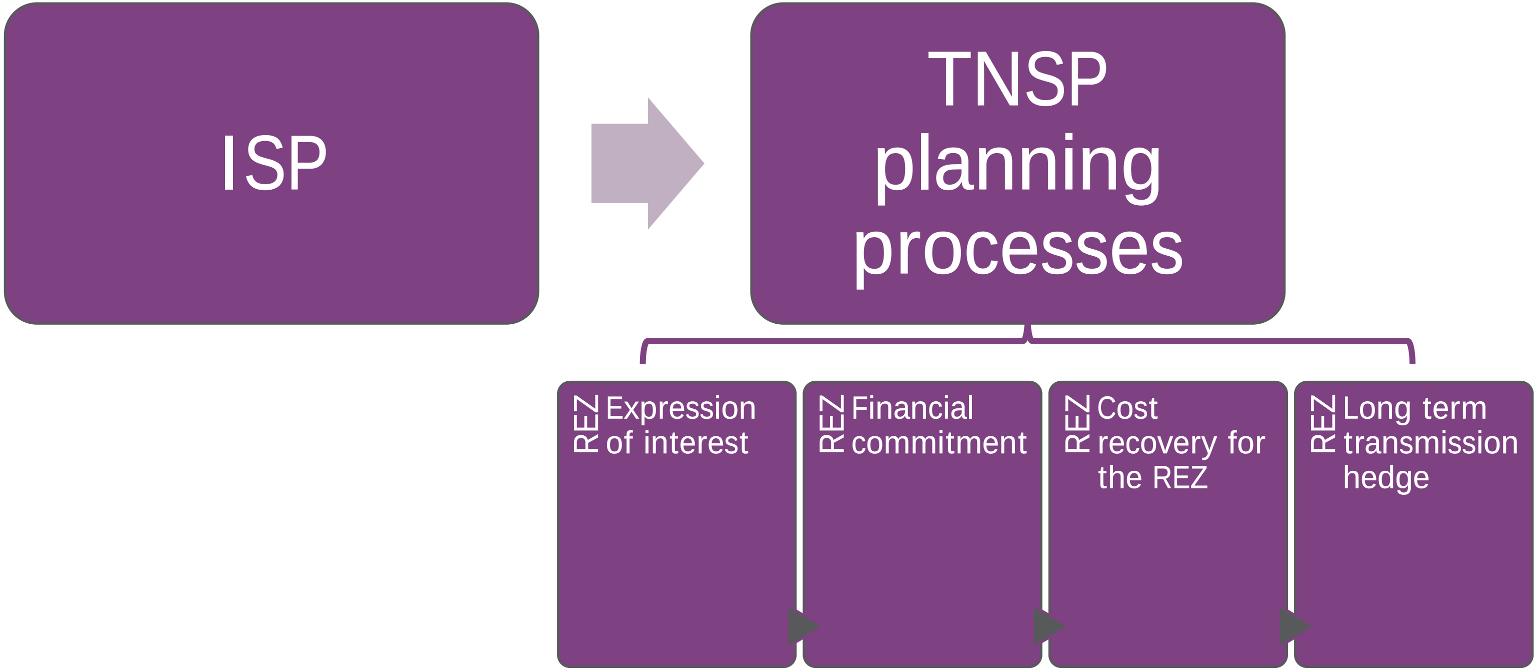
Type A REZ

- Connection framework
- SENE framework
- Information provision

Type B REZ

- Planning and investment process
- Funded augmentation

Proposed model for renewable energy zones



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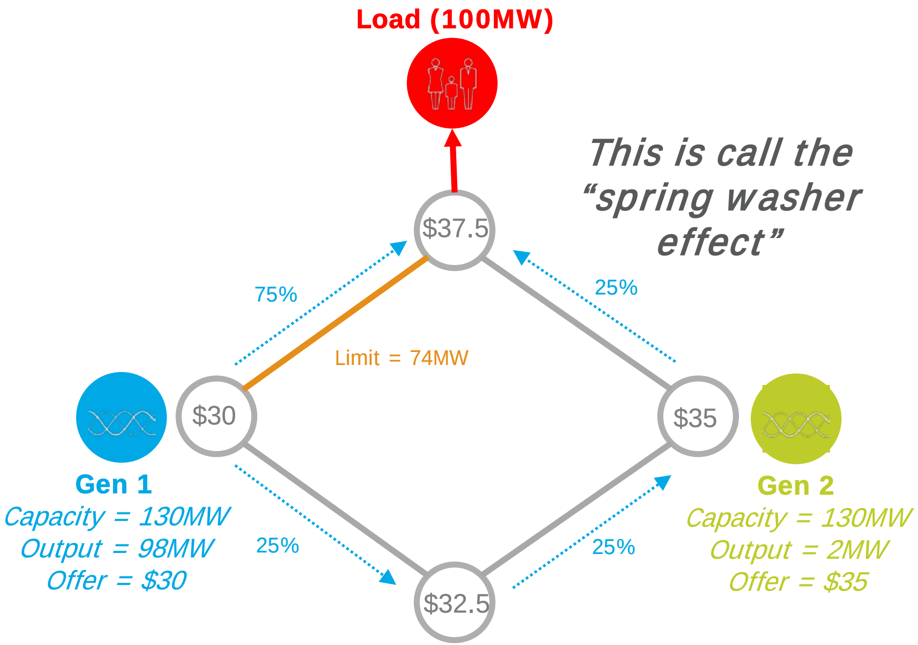
Dynamic regional pricing – detailed working

- To satisfy Kirchoff's laws, supplying an additional MW would require the generators to be **redispatched**
- For example, at the node where load is situated, the lowest cost way to supply the 1MW is to:
  - Reduce Gen 1 output by 0.5MW
  - Increase Gen 2 output by 1.5MW
  - Flow on orange line remains at 74: 0.5 x 75% - 1.5 x 25% = 0
  - LMP = 1.5 x \$35 – 0.5 x \$30 = \$37.5 (i.e., cost of increasing Gen 2 less saving from reducing Gen 1)



Assumes all lines have equal impedance.
Excludes effects of losses.