Exploring regional boundary definition and pricing models in the National Electricity Market

ACCI NEM Research: Task 1

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Executive Summary

Recent federal and state policy developments in Australia's National Electricity Market (NEM) are intended to improve reliability and put downward pressure on prices, while achieving Australia's emission reduction targets. The impetus for these actions is consistent upward price pressures on consumers the last 12-24 months and recent reliability events.

To date, policy developments have not considered a fundamental review of the NEM's regional pricing structure as one of the measures that could assist the market transition to a low carbon future, with increasing penetrations of Variable Renewable Energy (VRE). This report assesses whether alternative market structures for the NEM could be designed to achieve improved cost outcomes and contract liquidity for small to medium enterprises (SMEs).

An assessment of international wholesale electricity pricing models was performed to inform recommendations for the NEM.

The primary objectives of wholesale electricity pricing models are to produce locational pricing signals that promote:

- efficient short term utilisation of the existing network, by delivering electricity from lowest cost generators to customers that value it the most and;
- investment in generation and network infrastructure where it is most valued to the system

The increased market efficiencies from achieving these objectives needs to be assessed against the cost of implementing a different regional boundary regime or pricing models and potential implications to contract liquidity.

The NEM's current regional model provides an individual price signal for each of the five regions. Price differentials are caused by transmission lines between regions, known as interconnectors, reaching their rated capacity and becoming congested, which prevents the lowest cost generators from meeting demand.

The most sophisticated and efficient expression of locational pricing that could be adopted in the NEM is a nodal pricing structure. It can be utilised to correctly account for all transmission constraints (and in some cases, losses) by providing price differentials at all nodes in the NEM, which number in the hundreds. Although nodal pricing is costly to administer and has a lengthy implementation time, it is expected to increase the economic efficiency of the market.

The implementation of a nodal pricing system and the related financial instruments can limit the impact to existing generators, while incentivising more efficient future supply and decisions. Impacts to customers can be minimised by applying weighted average nodal prices across existing state based pricing regions, known as hubs. Hubs provide more stable prices for consumers by removing exposure to localised volatility and promote market liquidity by reducing locational risks to retailer portfolios.

International nodal markets have demonstrated they can have high market liquidity despite exposing generators to nodal price differentials with the development of effective hedging financial instruments. Mechanisms that have been designed and implemented in international markets to mitigate local market power caused by nodal pricing could also be adopted.

Given the flexibility in implementation, protections to consumers and incumbent generators while achieving increased market efficiency and promoting market liquidity, it is recommended that a cost benefit analysis of a nodal market be conducted for the NEM to inform a potential long term transition. This would be anticipated to achieve the best cost outcomes and promote market liquidity for SMEs.

The impact of adopting a nodal market is closely tied to the physical construct of the energy system of the future, that is, the precise nature of the generation and network system itself. Therefore the system studies being conducted by the Australian Energy Market Operator (AEMO) to facilitate the efficient development and connection of renewable energy zones with the oversight of the Energy Security Board, could evaluate whether a nodal market could optimise the intended outcomes for customers.

If further investigation determines the introduction of a nodal market is unsuitable or a shorter term solution is necessary, there is the opportunity for current regional boundaries to be adjusted. These can be adjusted in general terms to be smaller or larger to drive or complement the Energy Security Board's objectives.

In a 'large scale renewable future' based on the premise that state based incentives will drive this growth, network infrastructure within existing regions could become key constraints. The existing regions could be broken into smaller zones as a preventative measure, where new boundaries delineate these potential constraints.

Having analysed information from transmission network service providers, there are existing major power transfer locations within each of South Australia, New South Wales and Victoria that could rationalise a split into three smaller regions while Queensland could have four. Incidental impacts requiring further investigation would be increased market power of incumbents, reduced market liquidity from barriers to hedging between regions and increased price volatility, particularly for those areas with higher penetrations of VRE. Without effective mitigation measures, these negative impacts would flow through to customers in the respective regions.

In a more distributed generation future where rooftop solar photovoltaics (PV) and household battery storage dominate, interconnection between states may no longer be the key constraints. Constraints may also be reduced in the event of increased interconnection between existing regions in the NEM. If this were the case, a move towards larger regions could be proposed on the basis of increased competition and less price differential risk, therefore increasing liquidity.

The international review highlighted that many markets have progressed to being energy and capacity markets, while the NEM is an energy-only market. The increasing penetration of renewables in the NEM, with low marginal costs, is pushing higher marginal cost generation out of the market, generation which has historically been necessary for security and reliability of supply. The implementation of the National Energy Guarantee's Reliability Guarantee is expected to impact wholesale generation costs to the extent that this higher marginal cost generation is required.

The most mature, long term mechanism identified in the international review was a capacity market, however, implementation costs are expected to be high for any move to such a market in Australia. Capacity mechanisms that are market based could be an alternative or long term progression of the Reliability Guarantee. Examples of alternatives to capacity markets were found in the literature, however these require further investigation to determine their viability and applicability to the NEM. The alternative to incentivising new generation is to develop effective demand response measures, which are currently being pursued in the NEM to address near term reliability risks.

The international electricity markets reviewed for this report include the United States markets, PJM and California, New Zealand, Singapore, Great Britain, Ireland and Denmark. Secondary findings from the review included:

- VRE is found only in markets with targeted policies, such as renewable energy targets;
- VRE puts downward pressure on energy market prices in energy-only markets overseas, noting that much higher levels of regional interconnection in those markets mitigates reliability risks that have materialised in Australia;
- Transmission investment signals are most transparent in markets with nodal pricing, however, independent service operators (ISO) are still necessary to provide centralised planning and proposals for regulated assets. In the NEM, AEMO only acts as the ISO in Victoria;
- Significant market share in liberalised markets is held by large, vertically integrated energy utilities

The NEM's pricing structure is inextricably linked to the physical system and should be considered in any future system studies. Given the significant policy developments and transition in the NEM, a cost benefit analysis of a nodal market should be pursued and the opportunities for smaller or larger regions should also be considered as part of a holistic approach to planning its future.

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1 Introduction

The National Electricity Market (NEM) is experiencing price/demand volatility as total demand reduces, thermal generators are retiring and penetration of Variable Renewable Energy (VRE) is increasing. There have been significant reliability and security issues linked to major weather events in both South Australia (SA) and New South Wales (NSW), while retirement of coal generation, among other factors, has led to a significant increase in average wholesale energy pricing over the last two years.

This report examines whether the NEM's existing regional market structure is capable of facilitating the transition to a low carbon future and whether there might be a case for revised regions of the NEM to be defined in consideration of the existing and future presence of non-firm renewables. International wholesale electricity market pricing models have been investigated and options for alternative pricing models that may lead to better price and affordability outcomes in the NEM for customers are summarised. The international electricity markets reviewed for this report include the United States markets, PJM and California, New Zealand, Singapore, GB, Ireland and Denmark.

The report also presents renewable resource 'hotspots' with viable transmission capacity in the NEM that could be considered viable Renewable Energy Zones (REZs), and considers their impacts under alternative pricing models.

2 Current state of the market

2.1 Wholesale electricity market pricing models

Wholesale electricity markets are generally classified as energy-only markets - such as the National Electricity Market currently operating in east coast Australia, as well as New Zealand, Texas and Singapore - and capacity-plus-energy markets - which are predominantly throughout North America, Europe, Great Britain (GB) and Western Australia (WA).

2.1.1 Energy-only markets

In a wholesale energy-only market like the NEM, generators are paid for the electricity they produce based solely on the wholesale price applicable to each market price settlement period. The least-cost dispatch process used in the NEM means that generators generally bid into the market to cover their short run marginal cost of production, which for fossil fuel sources includes the cost of buying fuel.

In what is termed the merit order, bids are ranked in ascending order of marginal cost with lowest cost generators dispatched first and the more expensive ones brought in as necessary to meet the total load. Fixed capital costs are not specifically taken into account in the bid prices.

The market settles at the point where supply and demand are balanced, with the price of the marginal generator (the last generator dispatched) typically setting the price for all market participants in the trading interval. In a properly functioning short-term wholesale market, the spot price reaches extremely high prices at times of tight supply and very low (or even negative) prices during times of oversupply. By dispatching generation on the basis of marginal cost, the aim is to minimise the overall cost of electricity production.

Texas and Alberta are the only energy-only markets in North America, although Alberta has announced plans to transition to a capacity market in order to attract new investment as the province shifts away from coal-fired power as planned by 2030.

2.1.2 Marginal cost pricing and resource adequacy issues

Renewable generators inherently have low marginal costs (their fuel is free), which enables them to underbid higher marginal cost fossil fuel technologies in the merit order. This helps push higher cost generation out of the merit order which brings down the average marginal cost of production and average electricity prices which is known as the 'merit order effect'.

An energy-only market relies on scarcity pricing to send price signals for new investment. Short periods of extreme pricing volatility are necessary for generators to recover their fixed costs over the long term and to incentivise investment in new generation. A maximum price cap is set to protect energy consumers from very extreme prices, which is currently set at $14,000/MWh in the NEM. A fundamental challenge with the marginal cost energy-only market is that as the proportion of renewables in wholesale markets rises, wholesale prices will be driven so low that generators fail to recover sufficient revenues to cover their investment and signals for new investment stall.

For an energy-only market scenario with high penetration of renewables, pricing volatility must be extreme to ensure capital costs of firm complementary thermal generation or battery storage technologies can be recovered. A 2016 study estimated that under a 100% renewable energy scenario for the NEM, the market price cap may need to rise to between $60,000 and $80,000 per MWh (Riesz, 2016). However, such outcomes would likely lead to risks of financial collapse by participants and higher prices for customers as retailers will rely more heavily on contracts to hedge their risk in the market, which would lead to an increase in the average price of futures contracts.

2.1.3 Capacity markets

Capacity mechanisms are longer-term regulatory instruments whose purpose is to guide generation expansion according to the strategic view of governments and regulators.

In a capacity market, generators are paid through a mix of competitively auctioned contracts which pay their fixed capital costs, and revenue from the spot market. In general, capacity markets provide investors with a more certain revenue stream by providing a payment for capacity availability in addition to revenues obtained through supplying the spot market. Capacity markets can effectively overcome the challenges posed by resource adequacy in energy-only markets. They also enable lower price caps to be introduced to the wholesale energy market, which reduce volatility and price risks for customers and participants.

The UK Government has established a capacity market as part of its Electricity Market Reform policy to help ensure sufficient reliable capacity is in place to meet demand. The capacity market works by offering all capacity providers (new and existing power stations, electricity storage and capacity provided by demand side response) a steady, predictable revenue stream on which they can base their future investments.

In consideration of the NEM's reliability issues, the Finkel Review recommended a Generator Reliability Obligation (GRO). This would set a minimum dispatchable requirement in different regions that would be enforced in generator connection requirements. Since the Finkel Review, the Australian Government has proposed a Reliability Guarantee in its National Energy Guarantee. This mechanism will require retailers to forward contract dispatchable capacity based on minimum requirements set by the AEMC and AEMO.

2.1.4 Market design options to support low-carbon transition in the NEM

Measures to support a market-led transition to a low-carbon NEM that support price stability and reliability of supply are summarised in Table 2-1.

Table 2-1 Measures to support market-led transition to a low-carbon NEM

Option	Description
Capacity markets	▪ Regulated planning approach can define strategic capacity requirements and attract new investment or retain existing generation through capacity payments ▪ Capacity market mechanisms can be used as an alternative to the regulated approach to move risk from customers to suppliers
Auctions and PPAs	▪ Long term power purchase agreements (PPAs) can be used to provide revenue certainty for new generators ▪ Auctions to provide government price support to new generation through Contracts for Difference (CfDs) can be used to make up the difference between the price set by bidding and the market price paid to generators

Option	Description
Demand response	- Cost reflective price signals and a regulatory framework to support demand response can reduce price volatility in wholesale electricity markets - Low price situations can be exploited by flexible consumers which would limit the frequency and depth of low prices, therefore providing the investment signals needed - Putting a cost reflective price on shaving off peak demand would have a similar effect of reducing price volatility and flattening the demand curve - Some power system operators in the US already make extensive and large scale use of demand response. The Electric Reliability Council of Texas (ERCOT) sources approximately 50% of its supplemental reserves from demand response while a third of the new market for provision of electricity capacity in PJM is demand response
Locational pricing (eg nodal marginal pricing)	- Provides the most efficient short and long term price signals by virtue of any transmission congestion leading to differences in the marginal prices at every node - May be effective in assisting the market to transition to a low carbon future by providing more cost reflective signals for transmission constraints associated with REZs
Operational reserve demand curve (ORDC)	- ERCOT has designed their market to allow energy prices to reflect the opportunity cost of providing reserves. This is done using an ORDC which uses a price-adder that is included in the clearing price for energy, closing the gap between the energy market price set through trading and a fuller price that includes the value of security of supply
Two part “variable” and “dispatchable” market	- An innovative alternative advocated by a number of specialists in electricity market design to the existing wholesale market - Includes a two-part market structure that differentiates between variable, or ‘as available’ generation, and dispatchable or ‘on-demand’ generation

The options that are mutually exclusive and aim to incentivise long term investment in dispatchable generation are capacity markets, operational reserve demand curve and a two part variable and dispatchable market. These three options could be considered as alternatives or future market progressions to the GRO and Reliability Guarantee.

The GRO was a short to medium term application measure while the Reliability Guarantee places an implicit value on capacity through existing contract methods. A capacity market with reverse auctions would require new market structures but is a lighter touch regulatory mechanisms that creates a transparent price and market for capacity. It could be an alternative to the Reliability Guarantee or an eventual progression.

An alternative to the GRO and Reliability Guarantee in the NEM would be the implementation of an ORDC similar to the ERCOT market to value secure supply while remaining an energy-only market.

2.1.5 Nodal, zonal and uniform marginal pricing

Wholesale electricity markets determine either a uniform marginal price (UMP), a set of nodal (or locational) marginal prices (NMPs), or a smaller set of zonal marginal prices (ZMPs). The NEM currently operates under a ZMP structure compared to other energy-only markets which operate under a UMP (eg Singapore, Alberta, NZ) or a NMP (Electric Reliability Council of Texas, ERCOT).

Electricity networks convey electricity produced by generators to loads via a network of transmission and distribution lines. Discontinuities in the network may be designated as nodes, which are typically represented by substations where the voltage may be transformed from one level to another.

Nodal pricing represents the most sophisticated and efficient expression of locational energy prices as it correctly accounts for transmission constraints (and in some cases, losses), although it is the most complex to administer. When transmission lines are loaded up to their rated capacity, this leads to congestion in a nodal pricing market which results in differences in the marginal prices at every node, reflecting the scarcity of generation capacity and transmission capacity.

With zonal pricing, the power system is administratively divided into zones, at points where congestion is commonly expected. Zonal pricing only considers transmission constraints between zones, resulting in a single price within a zone and different prices between zones.

In a nodal price market design, all participants located at the same node will face the same price at that particular node, whether a generator or load. However, generators are typically located away from load centres, meaning trading parties end up located at different nodes on the network. This results in price risks due to congestion.

UMP markets are setup similarly to NMPs, however, loads are charged the weighted average of nodal prices across a single market or zone, sometimes referred to as a hub.

In a network without congestion and no network losses, where the lowest marginal cost generator can reach all parts of the network, the least-cost dispatch would be achieved by dispatching as per the merit order, as discussed in section 2.1.1. In reality, network constraints cause congestion, where the least cost energy cannot supply a load because transmission infrastructure has insufficient capacity to deliver that energy – resulting in higher cost energy in the constrained area being selected out of merit order and dispatched.

Dispatch in nodal electricity markets is determined by locational marginal pricing (LMP) by a Full Network Model (FNM). The model incorporates all physical characteristics and limitations of transmission elements in service at any point in time to create the merit order from lowest cost to highest cost (Gregan & Read, 2008, p. 3). This allows the dispatch price at each network location to reflect the marginal cost of supply at that point in time, given the network conditions i.e. congestion and loss factors (Gregan & Read, 2008, p. 3) caused by transient factors such as weather and outages.

The dispatch price used to determine dispatch volumes is the price used to financially settle transactions at the location (Gregan & Read, 2008, p. 3). The congestion pricing risk created for market participants who are typically buyers and sellers in different locations has resulted in the formation of many financial instruments that allow the hedging of this risk.

Nodal pricing markets can vary, in terms of how cost reflective they are for generators and customers. The price utilised to settle loads, who are retail electricity customers, can be load-weighted nodal average prices across many nodes in a hub (Frontier Economics, 2008, p. 29). The settlement for customers are similar to regions/zones used in the NEM, however, the hubs are typically smaller than the pricing regions utilised in the NEM (Frontier Economics, 2008, p. 29).

2.2 NEM market design

The NEM is divided into five regions and the wholesale spot price is settled at the Regional Reference Price (RRP) in which a market participant is located. The RRP is set as the marginal cost of supply at a Regional Reference Node (RRN), which are shown in Figure 2-1. The NEM can be conceptually considered to be in a hub and spoke structure, where the RRN is the hub and a spoke exists for any generation or load within the region (Gregan & Read, 2008, p. 4). The NEM rules define the RRN as the nodal price near the largest load or generation centre in a region (Gregan & Read, 2008, p. 43).

Regional boundaries in the NEM are selected such that transmission constraints are rare within a region and frequently occurring constraints are placed on region boundaries. The NER allows for boundaries to be reset as required whenever a constraint occurs for greater than 50 hours per year.

Trading between regions, known as inter-regional trading, occurs across theoretical links between RRNs (Gregan & Read, 2008, p. 5) – i.e. trading between NSW and VIC occurs between a theoretical link between Sydney West and VIC's Thomastown substation. The difference in RRPs creates a financial trading risk for participants if they contract energy from another region (AEMC, 2008, p. 57).

NEM dispatch aims to minimise total dispatch costs, by calculating a pseudo nodal price for all supply locations across the network, however, prices are settled at the RRP (Gregan & Read, 2008, p. 5). The pseudo nodal price implemented in the NEM is identical to the nodal price that would be implemented in an equivalent nodal model (Gregan & Read, 2008, p. 5).

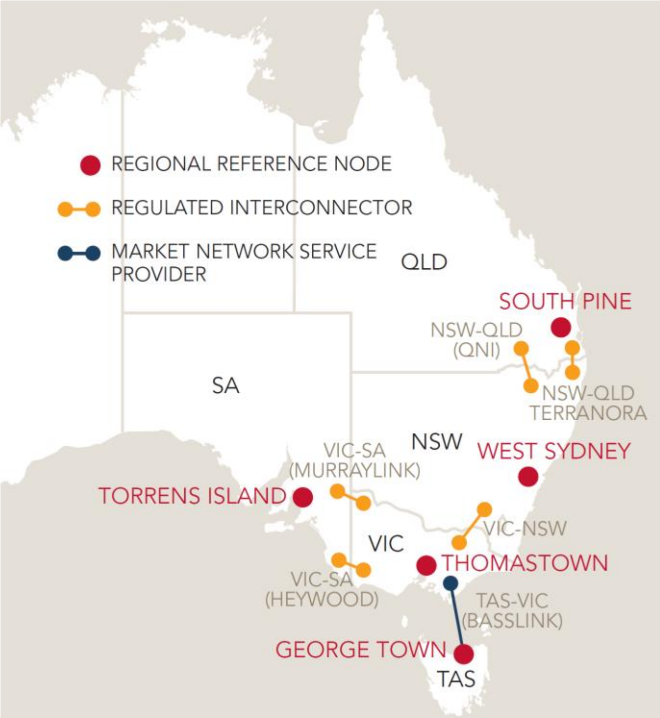

Figure 2-1 Regional reference nodes and interconnectors in the NEM
Source (AEMO, 2010)

Participants in the NEM are typically dispatched when their bid price is below their local pseudo nodal price (AEMC, 2008, p. 57), however, this is not always the case because of network constraints. There are situations where a generator is constrained-off – this is where it is dispatched less than the volume it bid, regardless of its bid being lower than the local pseudo nodal price (AER, 2012, p. 6). This generator is not dispatched because generators higher up the merit order have been dispatched due to congestion. When this situation occurs, a generator is incentivised to rebid at a lower price, potentially below its short run marginal cost (SRMC), to reduce the extent to which its dispatch levels will be decreased (AER, 2012, p. 6). When the dispatch model is determining the optimal dispatch to reduce congestion, it takes into account the generator's bid price as a proxy for cost (AER, 2012, p. 6). Consequently, if congestion persists it will dispatch higher volumes of the generator now that it is at a lower cost to alleviate the congestion. The generator can take a risk at offering below its SRMC because it will receive the RRP, which will be higher unless it is the marginal cost of additional supply region.

The RRP is set at the bid price of the generator who is last in the merit order to be dispatched, unless there is congestion where a generator is constrained-on – this is where a generator is dispatched for a quantity greater than the amount it is willing to produce for the settlement price (AEMC, 2007, p. 57).

The NER state the dispatch offer of a constrained-on generator **may not** be taken into consideration when determining the dispatch price (AER, 2012, p. 6). This rule is in place to prevent an individual generator having undue influence on RRP due to a constraint in the network. When a generator is constrained-on, it has the incentive to rebid its capacity in a higher price band or as unavailable to reduce the possibility/volume of it being continued to be constrained-on by the dispatch model (AER, 2012, p. 7).

Disorderly bidding by constrained generators, at a large scale, can result in pricing volatility that reaches the NEM's price floor and ceiling. It can also result in more generators being constrained than necessary, when generators closest to the constraint with the largest impact engage in disorderly bidding, resulting in generators further away having to be constrained to a greater extent.

Typically inter-region flows occur between a high-price region to a low-price region. These create surplus inter-regional residues when it is across a regulated interconnector (AEMO, 2010). A financially speculative auction process is run by AEMO for the rights to these residues, which enables Market participants to hedge against the inter-regional price risk.

The method used to model the transmission network constraints in the NEM is dependent on the location of the RRN, so if the RRN were to be changed the constraints would need to be re-formulated which affects the allocation of economic rents associated with congestion (Gregan & Read, 2008, p. 5).

3 International market review

International markets were investigated to determine whether the existing regional structure of the NEM is suitable for transitioning the market to a low carbon future. The specific aspects of international markets that were explored are:

- Regulatory context
- Value chain and participant profile
- Penetration of renewables
- Pricing volatility and absolute price levels
- Contract market
- Signals for transmission investment; and
- Customer impacts

The electricity markets investigated for this report were New Zealand, Singapore, GB, Ireland, Denmark and the US markets of PJM and California.

A high level 'traffic light] analysis was performed on the specific category of the market being assessed and is presented as an Appendix.

3.1 Electricity market contexts

The electricity markets examined exhibit significant variation in geographies, consumer base and connectivity.

- European markets have significant interconnection with other countries and have ongoing plans to improve this connectivity.
- The Californian and PJM, markets are of a scale larger than many countries – the Californian market serves approximately 30 million customers and is interconnected with several other adjacent regional markets. The PJM market serves a customer base of 61 million, covering 13 states and one district.
- Singapore's electricity market is dominated by gas powered generation (GPG) with gas being supplied by pipelines from Malaysia and Indonesia.
- New Zealand is the only electricity market that has a similar geographical isolation as the NEM, however, the population is significantly smaller.
- Interconnection to adjacent regional or national markets provides additional security and competition. It provides geographical diversity of generation and additional redundancy to the extent of the capacity of the interconnector.

3.2 Regulatory context

All the markets examined have full retail contestability except for the National Electricity Market Singapore (NEMS) which aims to introduce it in 2018. The GB market was the first to introduce retail contestability, as a means to put downward pressure on electricity prices offered to consumers.

California was the first US state to introduce market contestability but it experienced shortages of electricity in 2001, subsequently termed the 'Western power crisis'. Following this crisis, California transitioned to a nodal market and introduced a capacity market, which is discussed in more below.

The penetration rates of variable renewable generation are dependent on government incentives. Denmark, the GB and Ireland have high penetrations of variable renewable generation that have been driven by national renewable energy targets.

New Zealand has high penetrations of dispatchable renewables in hydro and geothermal, assets originally built by state owned enterprises that were since privatised. Other than recent expansion and refurbishment of ageing geothermal generators, no new hydro has been constructed in decades.

The US appears is similar to Australia in that in the US, states tend to have specific renewable energy targets under Renewable Portfolio Standards (RPS). California in particular, has targets for high penetration of VRE that exclude large-scale hydro while in the PJM, 9 out 13 jurisdictions have mandatory renewable targets.

3.3 Renewable penetrations

Renewable penetration has traditionally been dependent on availability of dispatchable renewable resources. A summary of the penetration of renewable energy, both total and VRE, as well as targets, is shown in Figure 3-1.

New Zealand has high penetrations of renewables from its abundant hydro and geothermal resources.

Denmark and California have high penetrations of variable renewable generation penetrations from being early supporters of government legislation promoting renewables. The Californian renewable energy target is more ambitious than other jurisdictional targets because it specifically excludes its large-scale hydro capacity. GB and Ireland also have national targets, which have incentivised construction of renewables.

Singapore is constrained largely by land area and less than ideal renewable resources.

The PJM only has mandatory state based targets across 9 out of 14 jurisdictions, resulting in a low average target. The penetration of renewables in the market cannot be analysed in isolation due to the flow on affects to price and security.

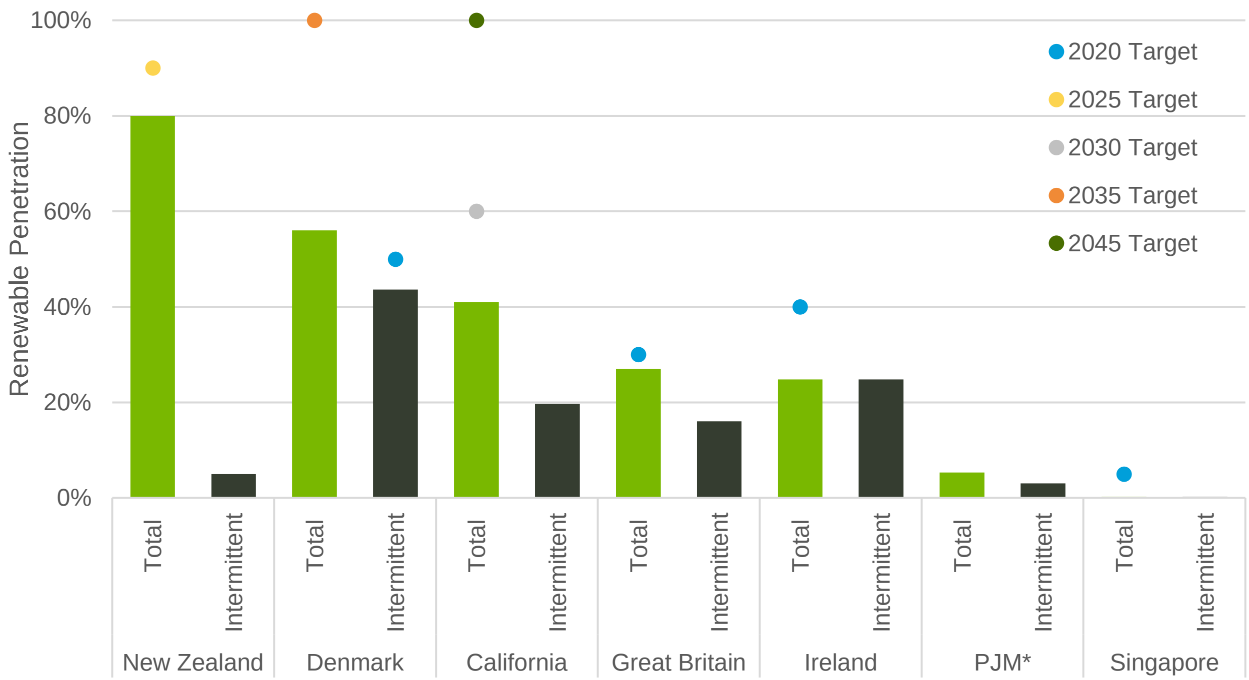

Figure 3-1 Total and intermittent renewable generation penetrations with 2030 targets

3.4 Value chain

Large, vertically integrated companies dominate the electricity markets investigated. These are either government owned or privately owned.

- The US, GB and New Zealand electricity markets have large vertically integrated energy utilities controlling large shares of energy generation and retail markets. The ownership and operation of the transmission networks tend to be managed differently between markets.
- In the PJM, the 9 largest companies generate 77% of the real-time market and 54% of the day-ahead market's load weighted average pricing.
- The day-ahead market forecasts demand on historical data and matches bids from generators and loads, while the real-time market is used to balance the differences between the forecast and real demand. This

is in contrast to Australia's NEM where it only has a real-time market. The day-ahead market is a financial market while the real-time market is a physical market (Cain & Lesser, 2007).

- Despite the concentrated ownership of generation, the PJM appears competitive in aggregate. Competition in the peaking segment of supply and local markets is lower, created by transmission congestion. The ability to leverage this localised market power is prevented by price caps that are enforced when congenstion is identified. The PJM transmission operator is independent of asset ownership – this enables ownership of transmission infrastructure by private companies.
- The GB market has three companies supplying 48% of electricity and six retailers accounting for 83% of the market in 2017, it was concluded that this segment of the market was moderately concentrated. Transmission is owned by three private companies across the market.
- The New Zealand generation and retail markets are both predominantly owned and controlled by five generation companies. The transmission network is owned and operated by a state owned enterprise, while there are 29 private distribution companies.
- The Danish, Singaporean and Irish markets appear to have less contestability and are predominantly controlled by government departments or corporations.
- The Ireland electricity value chain is primarily controlled by the government with little contestability in the retail segment. The transmission system operator and distribution operators are government owned companies while the retail market has been evaluated to be highly concentrated; meaning retail choice is limited for customers.
- The National Electricity Market Singapore (NEMS) has 13 generator market participants, with the share of the three largest reducing to ~58%. Retail contestability is limited to customers with demand greater than 200 kWh per year. The transmission and distribution network is wholly owned and operated by SP Group (SP), which is a private corporation with investments in Australia's network and retail markets. SP has a regulated revenue for its network infrastructure.
- The Australian NEM more closely reflects the value chains of US, GB and New Zealand than Denmark, Ireland and Singapore. In the NEM, transmission networks are now typically owned and operated by private companies with the exception of Powerlink in QLD.

3.5 Transmission investment signals

The transmission network in many electricity markets is a natural monopoly consisting of one large integrated network. The ownership and operation of the transmission network varies in different markets.

In Australia's NEM the Transmission Network Service Providers (TNSPs) in QLD, NSW and SA are responsible for planning and proposing transmission upgrades. Due to the TNSPs' revenues being based on their regulated asset base there is a conflict of interest, which requires regulatory oversight.

The regulatory process to approve a transmission network upgrade is called a Regulatory Investment Test (RIT-T). In VIC, the Australian Energy Market Operator (AEMO) is responsible for transmission planning. There has been ongoing debate as to whether there would efficiencies from AEMO becoming the single NEM wide transmission planner. The Finkel Review postulates there may be merit in future by having a single NEM wide transmission planer, with the logical choice being AEMO.

The more developed markets of CAISO and PJM both have independent service operators who are responsible for transmission planning. The PJM regional transmission organisation has reliability criteria that are used to propose new projects and fast track projects. The cost of transmission congestion in nodal markets can be easily calculated by the difference in nodal prices and the amount of energy flowing between the nodes when a constraint binds.

The necessity for an independent transmission planning authority or regulatory process is because the obvious conflicts of interest in the TNSP wanting to increase their regulated asset but and inability to identify a transparent or clearly defined mechanisms that enables transmission upgrades to directly compete in an open market. Ideally companies would be able to utilise transmission upgrades to compete with proposed generation to relieve congestion and meet demand.

Great Britain established the Transmission Investment for Renewable Generation mechanism, which supports renewable energy projects by reinforcing the network. In Addition Great Britain has a Transmission

Investment Incentives scheme, to fund transmission investment that may be needed to meet the Government's low carbon and renewable energy targets.

3.6 Electricity prices, contract markets and customer benefits

A direct comparison between the electricity prices between international markets needs to adjust for macro-economic factors (i.e. exchange rates, inflation, purchasing power, income, government policies and fuel markets). Considerations of these factors were beyond the scope of this project so it is advised that conclusions are not drawn from direct comparisons. Nonetheless, to provide an indication of the order of magnitude of electricity prices, the average price in the NEM for CY 2016 ranged between AUD$46 and $62 /MWh for VIC, NSW, QLD and SA in order of lowest cost to highest cost. TAS had higher costs because of localised issues. CY to date has seen substantial increases in average prices with the price range having increased to AUD$67 /MWh to AUD$109 /MWh with SA having highest costs.

The causation of general trends within each international market can be highlighted – particularly in light of the transitions to higher penetrations of intermittent renewables.

The PJM passes nodal pricing onto generators but averages prices across many nodes called hubs. Generators have been found to be responsive to changes in prices while retail customers have been fairly unresponsive to electricity prices. The pricing hubs also help facilitate trading which increases market liquidity.

In the PJM, loads have the option to elect nodal pricing in lieu of the load weighted average price. A load would choose this if their node was lower on average than the load weighted average and if they had the financial capital to ride out high priced periods. Customers in the PJM have experienced decreasing electricity prices since 2008, when accounting for inflation.

A significant driver for downward prices in the PJM has been the decrease in gas prices and the increase in penetration of zero-marginal cost resources i.e. variable renewables. Coal fired power plants are more commonly becoming the marginal resource to meet demand with upward price pressures from environmental regulation.

The volatility of the PJM energy market is price constrained with a market cap but the cost of the capacity market also needs to be taken into account. A capacity market is a market mechanism whereby generators are paid for being available for dispatch despite not generating. Capacity markets are implemented to ensure resource adequacy to meet peak demands.

Nodal markets are typically considered to have less liquidity than zonal markets, given the large number of nodes. An alternative view is that market liquidity is driven by efficient transmission use and a diverse ownership of generation and retailers. The latter appears to be supported with the PJM's Western Hub reported to likely be the most liquid forward electricity market in the world; and the total PJM having 55% of load contracted one year ahead, 33% for two years ahead and 11% for three years ahead (Climate Policy Initiative, 2011). Risks to nodal pricing differentials are effectively hedged by the highly competitive auction for forward transmission rights (FTRs), which are discussed in more detail later.

The experiences of the Californian and Texas electricity markets have also found no impact to market liquidity (Goldthau, 2017). The Californian market implemented a similar capacity mechanism to ensure sufficient resource adequacy. Load serving entities (i.e. retailers) are required to purchase 115% of their peak load a year in advance in the capacity market. The Californian market has seen downward pressure on wholesale prices from increasing penetrations of solar in peak hours, falling natural gas prices and low congestion rates. The market cap in the Californian market restricts volatility to a lower price than the PJM market.

The Danish market has two pricing zones, similar to the Australian market with 95% of prices being fairly stable in a price range of AUD$30/MWh. The price cap and floor in the Danish market are lower and higher respectively compared to the US markets.

GB has a single zone which enables all market participants to contract across England, Wales and Scotland. Historically, up to 50% of energy is sold through bilateral exchanges. The liquidity of the market was in decline between 2001 and 2014 was found to be lower than other energy commodity markets, which was a cause for concern as it created a barrier to entry into supply markets (Ofgem, 2016). Liquidity was improved by market reforms implemented in 2014 where there were increased reporting and transparency on forward products offered by the largest vertically integrated companies.

The electricity is traded on two power exchanges that feature day ahead and spot price markets. When a constraint binds the market operator performs redispatch operations to balance the market due to the zonal based system. One power exchange utilises a double blind auction process where offers and bids are made by buyers and sellers. The other market has a clearing price set by the highest marginal price generator dispatched. The Market introduced a competitive capacity market based on the PJM model in 2013 (Finkel, Moses, Munro, Effeney, & O'Kane, 2017).

The Irish market has traditionally found the price of electricity to be highly correlated with the price of natural gas. As renewable penetrations increase the price of electricity will be more increasingly influenced by the availability of wind power.

The Singaporean pricing volatility appeared to be largely influenced by security network constraints that were enforced to prevent the risk of oversupply on the NEMS. Retail choices are limited for small retail customers.

4 Potential NEM applications

The market design of the NEM has provided low prices historically since its implementation in 1997 (AEMC, 2007, p. 203). In recent years there has been consistent upward pressure on wholesale spot prices due to a range of factors including: increasing peak demand, decreasing overall demand, retirement of low-cost thermal generation, increasing penetration of variable renewable energy and high gas prices.

The current zonal market model in the NEM limits the exposure of price differentials within individual states on the east coast of Australia. This protects businesses that buy and sell within the pricing regions, however it exposes those across regions to pricing differentials.

The role of the differential in the short term is to signal for generation to be reduced in low-priced regions and increased in high-priced regions (AEMC, 2008, p. 56). In the longer term, the price differential signals for upgrades in transmission and investment in new generation for high priced regions (AEMC, 2007, p. iv).

Despite regional pricing signals, there have been recent security of supply events in SA and NSW. Price pressures were growing in SA as well as calls for a state-wide review leading up to the 2016 blackout. Following this, the Council of Australian Governments (COAG) commissioned the *Independent Review into the Future Security of the National Electricity Market* (2017), known as the Finkel Review.

The Finkel Review made recommendations on the basis of low cost and efficient implementation to address immediate concerns regarding security, reliability and long term policy for transitioning to a low carbon future (Finkel, Moses, Munro, Effeney, & O'Kane, 2017).

This section explores the long-term application of nodal pricing including the potential configuration of these nodes and the restructuring of the current regional boundaries.

4.1 Nodal pricing

High shares of VRE may lead to an increasingly constrained transmission system, particularly if new generation is clustered together around certain geographical areas to harness a common or correlated renewable resource. Since it typically takes much longer to plan, get approval for and build a high voltage transmission line than it does to build a solar or wind farm, transmission reinforcements are often significantly delayed. Therefore, it is reasonable to assume that a shift towards nodal pricing using a more accurate network representation over zonal pricing may result in greater efficiencies for the wholesale electricity market.

The intention of transitioning to a nodal market is to improve the efficiency of the market with more cost reflective price signals for the location of new generation, demand response and transmission upgrades. The intra-state risks caused by these pricing differentials can be managed with financial instruments, called forward transmission rights (FTRs). The method utilised to introduce FTRs can protect existing generators as the market transitions to the new model. Australia could utilise the learnings from other markets that transitioned to nodal pricing.

The cost of introducing nodal pricing as a regulatory reform would be unavoidable. The extent of the cost reflectivity of a new nodal market to generators and consumers can be designed to varying levels of degree. Generators could initially be protected while consumers could be charged at a trading hub price; where this equals the weighted sum of all nodal prices in the region (Gregan & Read, 2008, p. 43). This is similar to the 20 hub prices implemented in the PJM. In addition a load could be provided the option to receive its hub price, similarly to the PJM.

Larger hubs result in more stable prices for customers by averaging fluctuations through cross subsidisation of higher price nodes by lower price nodes. Cross subsidisation has been supported because consumers have been found to be unresponsive to changes in price. New technologies however, are providing the opportunity for demand response activities. Demand response would reduce prices but the price signals for these activities would be masked by larger hubs. Demand response availability and access by varying consumer groups would need to be carefully investigated before making decisions that will greatly impact future electricity pricing.

The implementation of nodal pricing in California has been found to provide better price signals and more liquidity in comparison to the previous zonal model, however, it took 7 years to transition and is a more complex model requiring significant commitments in time and resources (London Economics, 2014, pp. 62-63). The key advantage of the framework for local generation and delivery costs at 3,000 system nodes, is that it improves economic efficiency through cost reflectivity and provides a platform for the California Independent System Operator (CAISO), to address transmission congestion (London Economics, 2014, p. 62).

Nodal pricing can help relieve congestion by attracting new generation from higher nodal prices (London Economics, 2014, p. 62). Congestion relief would have been in the order of years for the procurement of new generation plant, however, developments in batteries and solar PV could respond in periods of 6 to 18 months.

Nodal models were investigated by the Australian Energy Market Commission (AEMC) in 2008 as a method of reducing congestion. The recommendation was made by Gregan and Read (2008, p. 31) for the NEM to adopt the same dispatch model utilised in a nodal market, known as a full nodal model, regardless of implementation of nodal pricing for the following reasons:

- Generation can be dispatched on a nodal basis while still interpreted from a RRP
- Congestion pricing regimes could be introduced as desired
- Nodal prices to be used directly rather than the calculation of pseudo nodal price.
- A full nodal model would provide a more accurate approximation of power system conditions (Frontier Economics, 2008, p. 70).

The application of nodal pricing would require the inclusion of a market that enables market participants to hedge against local marginal pricing differences, similar to the inter-region residue auction.

In the NEM, generators currently hold the implicit right to be settled at the RRP, which protects them from congestion price risks within the region (Gregan & Read, 2008). If a nodal market were implemented, generators would lose this right, which provides some justification of the allocation of free or grandfathered FTR (Frontier Economics, 2008, p. 70).

Where price differences between a local trading hub and the reference node of a generation or demand asset are significant, generators can use FTRs to hedge the locational price difference. Financial Transmission Rights (FTRs) entitle the holder to a stream of revenues (or charges) for differences between energy prices at source and delivery nodes (Climate Policy Initiative, 2011).

FTRs are point to point instruments according to their power injection point and power withdrawal point (Frontier Economics, 2008, p. 32). In the PJM, they are available for any nodes for which posts a Day-Ahead Congestion Price (Frontier Economics, 2008, p. 32). The holder of an FTR receives/pays the difference in price between the nodes multiplied by the amount specified in the FTR, depending on the price difference between the nodes (Frontier Economics, 2008, p. 32).

FTRs do not grant rights of physical transport of electricity. Instead, they grant the holder access to financial compensation equal to the congestion and/or loss rent associated with the locational price differences. They represent a critical hedge to nodal price risk for generators and ensure service rights to customers (Climate Policy Initiative, 2011).

The PJM was the first market to introduce FTRs and initially allocated them to incumbent participants (Frontier Economics, 2008, p. 33)**.** This allocation mechanism was found to detract from competition as well as the subsequent model. The current model, auctions off all FTRs in annual and monthly processes where transmission customers, as the payers of regulated transmission charges, receive the Auction Revenue Rights (ARRs) (Frontier Economics, 2008, p. 34). When new control zones are added to the network, participants are eligible to receive an allocation of FTRs for the first two years. Following this, they are only eligible for AARs, which they need to purchase as FTRs if they wish to self-schedule (Frontier Economics, 2008, p. 34).

Additionally, ARRs are allocated in parallel to FTRs as a long term risk hedging tool, typically for a 10-year period but can go up to 30 years in case of a transmission expansion. They are intended to encourage participation in the FTR markets and increase liquidity. The winning participants in the FTR auctions are granted ARRs to ensure liquidity of the congestion/transmission market and increase competition. (Climate Policy Initiative, 2011).

Mechanisms for controlling local market power, from transmission congestion, could be reconsidered in the NEM with the adoption of nodal pricing. The constrained-on and off mechanism introduces market inefficiencies from disorderly bidding. The PJM demonstrates the requirement for regulatory measures to manage localised market power. The PJM market introduced the Three Pivotal Supplier Test, which determines whether there is adequate supply available to relieve a constraint whilst still being competitive (Keech, 2014).

The energy price caps in the US markets are set at lower amounts because the energy markets are intended to cover variable costs while the fixed costs are remunerated by capacity markets (Frontier Economics, 2008, p. 6)

Nodal pricing still has some challenges with the reliance of bid-based dispatch rather than actual generator costs, which may provide opportunities for the exercise of market power (Frontier Economics, 2008, p. 36).

There has been significant debate in the benefits attributed to the PJM moving to nodal pricing (Frontier Economics, 2008, p. 37).

4.1.1 Potential node and hub locations in the NEM

Table 4-1 lists locations in each NEM state region that represent the major load transfer points within the market and generator connections. These could be potential locations for a less granular application of nodal pricing to ensure reflective pricing of the key intra-regional constraints for generators.

The financial impact to incumbent generators could be minimised by the implementation of hedging products, while still incentivising more efficient bidding behaviour, similarly to the PJM. Impacts to customers could be minimised by applying weighted average nodal prices across the existing state based pricing regions, with the potential option for customers to opt out and receive their local marginal price. State based allocation is rational with existing interconnector constraints and current cross-subsidisation of customers within states. If interconnection no longer presented primary constraints, alternative delineations for hubs could become preferable i.e. combining adjacent nodes across states with similar average prices to provide more protection from volatility.

Customers at lower priced nodes could elect to opt out, while those at higher priced nodes could be presented with the opportunity to participate in demand response activities. These opportunities would promote economic efficiency by reducing the extent of cross subsidisation, by customers capable of responding. Given the potential market efficiencies that could be achieved and protection measures, it is recommended a cost benefit analysis be performed, despite the complexities and cost of implementation.

Table 4-1 Potential locations for NEM State nodes

South Australia	Victoria	New South Wales	Queensland	Tasmania
South East Robertstown Davenport	Ballarat Moorabool Hazelwood Loy Yang	Armidale Bayswater Wallerawang Yass Wagga 330 Canberra/Queanbeyan Buronga/Red Cliffs	Ross Strathmore Nebo Broadsound Bouldercombe Calliope River Callide Tarong Braemar South Pine Middle Ridge Bulli Creek	George Town

4.2 NEM regional boundaries

4.2.1 Background and regional changes to date

The NEM originally had 5 regions in its formation in 1997, set along state boundaries, before Tasmania joined in 2005 (AEMC, 2007, p. 203). The Snowy region was abolished in 2007 by the AEMC.

The AEMC concluded that investment was unlikely to address the congestion in the short or medium term, due to the high market cost of taking lines out of service to upgrade them and the environmental issues associated with the development of transmission lines or generation in a national park (AEMC, 2007, p. 19).

The AEMC chose to abolish the Snowy region by allocating Murray generation to the Victorian region and Tumut generation to the NSW region because quantitative modelling found it to achieve the best dispatch efficiency out of the alternatives considered (AEMC, 2007, p. 21). Major considerations were the incentives for Snowy Hydro to engage in disorderly bidding and withholding generation to prevent congestion and maintain access to higher market prices (AEMC, 2007, p. 20).

The decision on the appropriate region boundaries was based on technical criteria in the National Electricity Code regarding the design of regions and modelling losses ((NEMMCO - TIRC, 1997) as referenced in (AEMC, 2007, p. 203)). The selected configuration was based on current transfer flow measurement points (AEMC, 2007, p. 216).

The region division was intended to allow market prices to reflect the real-time cost of transmission congestion (AEMC, 2007, p. 203). The original version of the National Electricity Code envisaged region boundaries would be revised annually and changed as required to reflect new points of “material congestion” (AEMC, 2007, p. 203). Materiality was to be assessed on technical criteria, which included whether optimal dispatch was disturbed for more than 50 hours by constraints in a financial year (AEMC, 2007, p. 203).

The AEMC (2007, p. iv) reformed the criteria and process for region change in Chapter 2A of the National Electricity Rules to require the following process steps (AER, 2017, pp. 51-52)[1]:

- Identify a congestion problem
- Present a preliminary case as to the economic efficiency of a proposed region solution
- Be technically competent
- Appropriate having regard to alternative means for managing congestion
- Propose an implementation period

The sizing of zones requires implies a trade-off between more efficient spot price signals and contract liquidity. Smaller zones provide more efficient spot price signals for short run utilisation of the network and potentially long term investment but may reduce hedging opportunities and increase the cost of hedging. Larger zones on the other hand, increase inefficiencies by reducing spot price signals but yield more efficient hedging. Merging zones that rarely experience pricing differences from congestion, may prove beneficial from the efficiency gained in liquid forward markets (THEMA Consulting Group, 2013).

4.2.2 The case for larger regions

The precedent set by the Snowy region abolition resulted in the Process for Region Change, Rule Determination, where the circumstances required to justify larger regions in the NEM under the National Electricity Rules were found to be as follows:

- There would need to be an identified congestion problem that has significant barriers to removal and a solution with a better economic dispatch solution. There would need to be short to medium term barriers to new generation entrants and transmission upgrades to prove the congestion is material and enduring.
- There would need to be a solution that results in a more economic outcome for consumers – the barriers to congestion relief means the proposed solution would need to create a situation where it improves

[1] There are additional requirements if the congestion problem has been considered within a 5 year period (AER, 2017, p. 52).

efficiencies of dispatch in respect to bidding incentives and dispatch outcomes, forward contracts, the spot market and long term dynamic efficiency (AER, 2017, p. 52)

- The proposed region change would need to be justified as superior to alternative market activities.

There do not appear to be any short to medium term barriers between any existing NEM regions. At present there is significant direct intervention and policies by federal and state governments to increase generation capacity. Examples of direct intervention are the South Australia's lithium-ion battery and concentrated solar thermal power plant, Snowy Hydro 2.0 and state government renewable energy targets in all regions.

A further counter argument to the enduring nature of the inter-region constraints are the interconnector augmentation plans in the latest National Transmission Network Development Plan for each region of the NEM (2016, p. 28).

Under the current National Electricity Rules there does not appear to be a case for merging existing regions that fulfil all requirements. The main justification for merging regions from the international review would be to increase market liquidity – either as a response to critical shortages in forward contracts or due to a lack of congestion between regions. There would also be alternative market reforms that could occur to increase liquidity, such as those implemented by GB to reverse the trend of reducing liquidity.

There could be future scenarios where interconnectors between existing regions are no longer key constraints in the market. If this were to occur due to a more distributed future market or upgraded interconnection there could be a case for larger regions.

4.2.3 The case for smaller regions

Smaller regions could provide pricing signals for intra-regional congestion along the proposed borders. The smaller regions would provide more localised RRP that would be inherently more cost reflective and signal investment for new generation or interconnection.

Having analysed the intra-network constraints identified by AEMO in the NTNDP and the individual transmission Annual Planning Reports the following potential region breakup was proposed:

- SA could be divided into three regions around the nodes South East, Roberts Town and Davenport.
- VIC could be divided into three regions along the Victorian Alps, Melbourne & Latrobe Valley and in the west
- NSW could be split into three regions, around the north, Sydney and the Snowy Mountains
- QLD could be broken into four regions with north, central, south east and west.
- TAS – single zone due to scale of load

The high level analysis of the networks took into account that zones should have load and generation centres to enable market liquidity.

Given the development of renewable energy zones, smaller regions could be proposed as a preventive measure of intra-regional constraints becoming key congestion locations in future.

The case for smaller regions would need to be carefully considered in light of the international and literature learnings.

GB assessed the case for smaller regions on the basis that inappropriate bidding zone delineation was resulting in increasing costs for the system operator and potentially sub-optimal investment decisions. More reflective short run price signals for network users encourages more efficient use of the existing network capacity – through generator dispatch and demand. A study concluded smaller zones in the Nordic market to result in overall socioeconomic benefits that would be distributed evenly between stakeholders. A similar study in Germany found minimal difference on the effectiveness of congestion management when number of zones were increased (Ofgem, 2014). Despite this it was concluded that there should be an overall fall in average prices for consumers across all zones due to increased net market efficiency. Prices will likely fall in export-constrained regions and increase in import constrained regions with high demand.

Smaller zones could reduce market liquidity without efficient hedging instruments. This could result in investment inefficiency from increased risk and transaction costs. Nordic markets have been found to be small zones with strong levels of liquidity, however, smaller zones have still been noted to typically have poor liquidity of hedging instruments (Ofgem, 2014). The potential welfare losses resulting from impacts to liquidity would need to be carefully considered when further assessing the case for smaller regions, given the lack of consensus in the literature.

Pricing signals that provide a more accurate reflection of congestion constraints would be intended to incentivise investment in generation where it is most valued to the system. Other practical considerations that may mitigate these signals are government policies promoting certain technologies, contracts for difference and uncertainties about future generation investment, demand growth, social license and the processes for transmission investment.

Despite smaller zones providing more efficient pricing signals, there is limited ability to influence transmission investment because of lengthy lead times, centralised planning and approval processes and high capital investment. It is argued transmission operators are already aware of network constraints and would receive no additional information.

4.3 Renewable energy zones

The Finkel Review outlines the need for a more strategic approach to transmission planning that is focused on achieving the best outcomes for consumers as a whole over the long-term and to support a smooth transition to a low carbon electricity market outcome. The review recommends a greater strategic planning approach should increase diversity of generation and locations, including the development of new Renewable Energy Zones (REZs).

The Australian Energy Market Operator (AEMO), supported by Transmission Network Service Providers (TNSPs) and other stakeholders, are to identify transmission network routes to efficiently connect REZ to the network, as part of an integrated grid plan. The plan is recommended to be released by mid-2018, reviewed annually initially and with qualifications that REZ may be years off from being connected due to economic reasons.

Despite the qualification REZs could be years away, the identification of REZs could result in the establishment of transmission investment funds similar to Great Britain. In Texas' ERCOT market, the government passed a directive to establish Competitive Renewable Energy Zones in 2005. The appropriate body identified areas with potential wind capacity, built the necessary transmission infrastructure to enable to area to be developed and funded it by passing the costs through to the consumers.

The Finkel Review acknowledges the potential future role of government to facilitate considered and targeted investments if there are unresolvable coordination problems between generators and TNSPs under the existing regulatory framework. To achieve this end the government would need an up to date list of potential projects prepared by AEMO in consultation with TNSPs recommended to be prepared by 2019. The process being proposed has similarities with PJM and CAISO's standard transmission planning processes, however, AEMO's responsibility would be more far-sighted.

Nodal Marginal Pricing (NMP) would not necessarily be able to support the identification of REZs because of the long-term holistic approach required. The holistic and long-term view recommended to be taken for the identification of REZ will not necessarily be substantially impacted by more accurate details of existing congestion. However, given the long lead times for planning approvals and construction of new transmission infrastructure compared to VRE projects, NMP would greatly complement the transition.

The current number of proposed VRE projects reported in the TNSP planning reports and VRE required to meet federal and state renewable targets are sufficient to cause constraints, as already identified by AEMO. The proposed projects in TNSP annual planning reports that were mapped onto Figure 4-1, provide an indication of REZs from a bottom-up private investment perspective. For the full potential of these proposed projects to be realised, grid augmentation to the transmission network will be required. A NMP market would be able to provide cost reflective location pricing that would guide the efficient location of VRE on the existing network until REZs are identified and developed.

IRENA (IRENA, 2017) supports the recommendation of more detailed spatial resolution in the wholesale market from NMP may represent a useful solution, until transmission augmentation can match the VRE project time frames. The transmission network will become increasingly constrained due to the geographical concentration of wind and solar resources.

Due to the lengthy implementation period of nodal markets, there may be an interim solution of smaller regions to appropriately signal the cost of intra-regional constraints to these REZs.

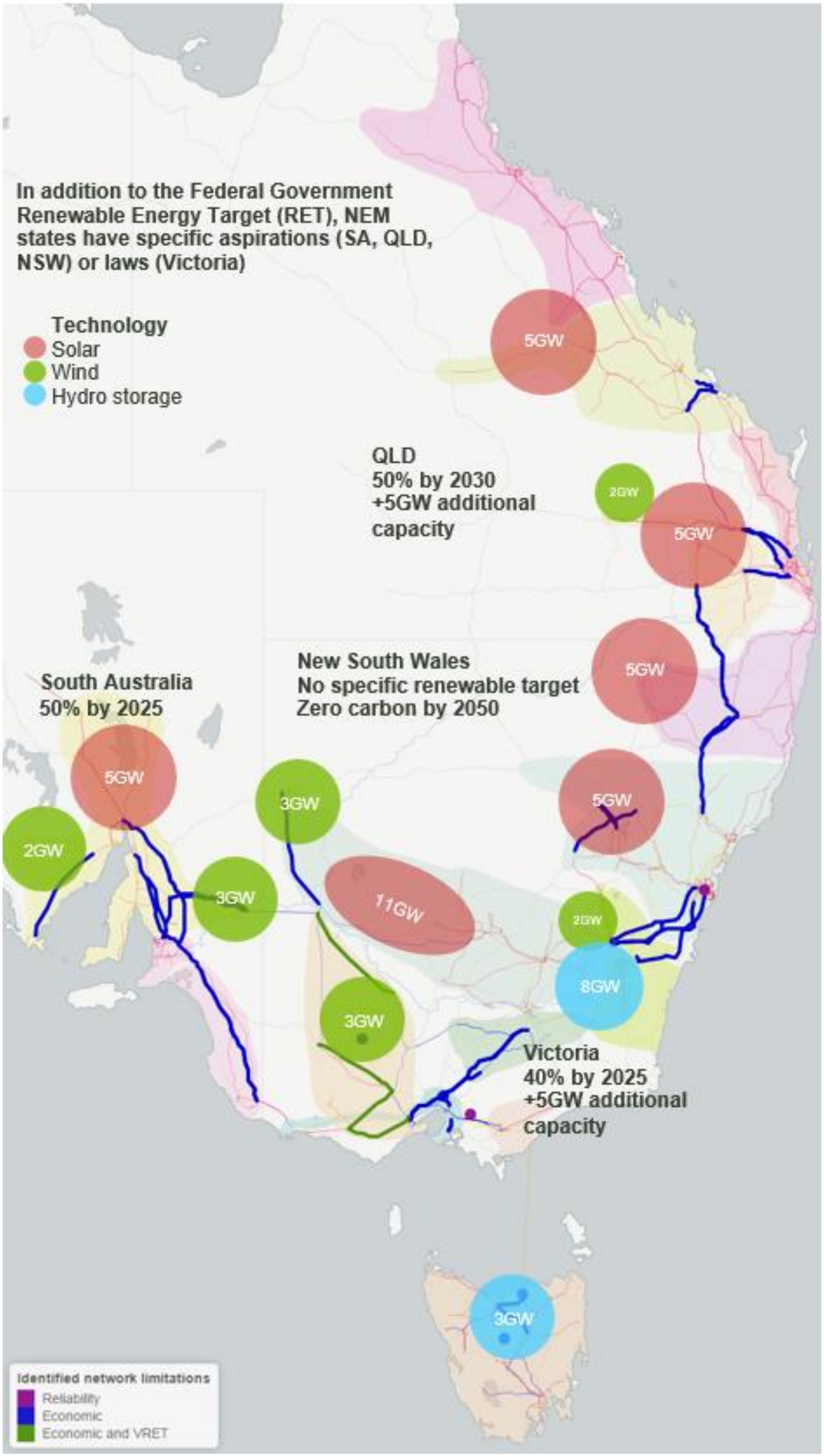

Figure 4-1 Transmission network constraints and proposed renewable projects
Source: as per ACCI NEM Research Task 3

5 Concluding remarks

The NEM’s locational pricing signals aim to achieve efficient short term utilisation of the existing network and generation and network investment to be located where it is most valued to the system. The system implemented must consider the market efficiencies gained compared to the implementation cost and potential impacts to market liquidity.

The NEM’s locational pricing signals could be improved to reflect all constraints in the transmission network by transitioning towards a nodal market. A nodal market is the most sophisticated market design for locational pricing and have been observed to be successful in North American nodal markets. These markets have effectively managed market concentration and achieved increased liquidity of forward contracts through financial instruments and local market power control mechanisms, however, they are costly to administer and have lengthy implementation periods.

The implementation of nodal pricing can limit the impact to existing generators, while incentivising more efficient future supply and decisions. Impacts to customers can also be minimised by applying weighted average nodal prices over existing regions. These could be reassessed as primary constraints alter in the future and alternative hubs could become viable.

Given the flexibility in implementation, protections to consumers and incumbent generators while achieving increased market efficiency and promoting market liquidity, it is recommended that a cost benefit analysis of a nodal market be conducted for the NEM to inform a potential long term transition. This would be anticipated to achieve the best cost outcomes and promote market liquidity for SMEs.

If a nodal market is found to be unsuitable or a shorter term solution is required, the adjustment of regions could be made under the existing regional pricing model.

Smaller regions would provide more accurate pricing signals along the constraints they are designed to delineate. They could be used as a preventative measure in a ‘large scale renewable future’ to prevent intra-regional constraints becoming critical. There are already primary power transfer locations within all regions except for Tasmania that could rationalise smaller regions. Incidental influences to specific regions that would require consideration and management are increased market concentration, reduced liquidity and potentially increased price volatility for generators and customers. Mitigation measures and policies could be implemented similarly to a nodal market, however, these will increase the cost and complexities of implementation. These are factors that would need to be investigated further to propose a move towards smaller regions.

There may be several future scenarios where interconnectors between regions no longer become key constraints on the market. This may occur in a more distributed generation future where rooftop solar photovoltaics (PV) and household battery storage dominate or there is increased interconnection between existing regions in the NEM. If this were the case, a move towards larger regions could be proposed on the basis of increased competition and less price differential risk, therefore increasing liquidity.

The impact of adopting a nodal market or adjusting region sizes is closely tied to the physical construct of the energy system of the future, that is, the precise nature of the generation and network system itself. Current system studies currently being complete by AEMO under the oversight of the Energy Security Board should consider how the pricing structure design can drive or complement objectives as part of a holistic planning

The international review highlighted that many markets have progressed to being energy and capacity markets, while the NEM is an energy-only market. As a consequence, the NEM’s energy-only market is facing resource adequacy issues because of increasing VRE penetrations pushing higher marginal cost generators out of the market. The most mature mechanism identified to address this issue is a capacity market. This mechanism could be an alternative or long term progression of the proposed Reliability Guarantee, however, it will require new market structures and be more costly to implement. Alternative measures were identified but require further investigation to determine viability. Lastly, demand response mechanism can provide a similar function and are already being pursued in the NEM.

The review of international wholesale electricity markets has shown that other electricity markets are experiencing or have already experienced similar challenges to Australia. These experiences have informed the conclusions of this report while being mindful of fundamental market differences.

Appendix A- Supporting information

Electricity market & Market context	Regulatory context	Value chain	Renewable penetration	Pricing volatility and absolute price levels	Contract market	Signal for investment in new transmission	Customer benefits
PJM Full nodal pricing 65 million people in 13 states and 1 district (PJM, 2017) 183 GW installed generation capacity Day-Ahead Energy Market and a Real-Time Energy Market Capacity market LMPs reflect: system energy price, congestion price and loss price.	Competitive wholesale electricity market. (PJM, 2017). Has Regional Transmission Operators who do not own transmission systems[2] State divesture of generation assets and introduction of retail contestability varies (Morey & Kirsch, 2016, p. 23). Defined percentage of retail suppliers' load to be served by renewable resources depends on individual state legislation. Defined in 9 jurisdictions (states or district), voluntary in 2 and 3 have no standards. (Morey & Kirsch, 2016, p. 312).	Number of members in the value chain were 1016 as of August 30, 2017. Owned by 132 parent companies with many vertically integrated. 19 parent companies own 210 subsidiaries[3]. Aggregate market evaluated as competitive Generator participants generally make offers at or close to marginal cost in Day-Ahead and Real-Time Energy Markets Highly concentrated ownership in peaking segment of supply Highly concentrated ownership of supply in local markets created by transmission constraints (PJM, 2017, p. 9) In 2017, Jan 1 to Jun 30, 9 parent companies generated 77.4% of real time load weighted LMP. The other 22.6% was made up 66 companies. In the Day-Ahead market, 9 companies control 53.9% of load weighted LMP (PJM, 2017, p. 103).	6.5% of renewables, which comprises of less than 1% of intermittent generation sources (PJM, 2017). The 9 jurisdictions with renewable portfolio standards range between 12.5% and 35%.	Less-flexible units are more regularly marginal resource to meet demand due to sustained lower natural gas prices, increased enviro regulation and penetration of zero-marginal cost resources (PJM, 2017, p. 3) Jan to June 2017 total price AUD$64 /MWh[4], largest cost components load weighted energy, capacity and transmission services charges. Offer capping at USD$2,000 /MWh unless cost above can be proven or there is a shortage where the cap lifts to USD$3,700 MWh[5]	Forward market high liquidity and competitiveness: 55% of the total PJM energy to serve load for the year is contracted on one year ahead interest, 33% for two years ahead, and 11% for three years (Climate Policy Initiative, 2011)	Transmission investments have not been fully incorporated into competitive markets. There is no transparent or clearly defined mechanism to permit competition between generation and transmission when a generator retires or load increases (PJM, 2017, p. 514)... In the first 6 months of 2016, eleven control zones experienced congestion when a constraints binds for 50 or more hours (PJM, 2017, p. 22). PJM baseline transmission projects resolve reliability criteria violations. Projects with multiple violations are a subset of significant baseline projects called backbone transmission projects, 3 of these are currently under development (PJM, 2017, p. 512).	Retail customer prices are determined at 20 hubs, which are stable by taking the load weighted average of many nodes (Climate Policy Initiative, 2011, p. 3) Inflations adjusted total price of electricity shows it varying from AUD$47 /MWh in 1999, peaking at AUD$80 /MWh in 2008 and reducing to AUD$42 /MWh in 2016. (PJM, 2017, p. 18) Transmission charges decreased to 4% of electricity price in 2005 and increased to 17% in 2016 (PJM, 2017, p. 19) Loads can choose to elect nodal pricing, but has to ensure hourly metering separates a customer's own load from others on the bus. (Fernandez, 2016)

[2] http://www.pjm.com/about-pjm/who-we-are/pjm-history.aspx
[3] http://www.pjm.com/about-pjm/member-services/member-list.aspx
[4] USD to AUD = 1.25
[5] http://www.pjm.com/~/media/committees-groups/committees/mrc/20160824/20160824-item-01-day-ahead-overview.ashx

Electricity market & Market context	Regulatory context	Value chain	Renewable penetration	Pricing volatility and absolute price levels	Contract market	Signal for investment in new transmission	Customer benefits
California Day-Ahead Market Real-Time Market 71.4GW total installed capacity[6] 38 million-plus residents (London Economics, 2014, p. 47) The CAISO has a bilateral spot market for capacity, which is part of the Resource Adequacy program – where generators can sell capacity on a month-ahead and year-ahead basis to load serving entities (London Economics, 2014, p. 50). Load serving entities are required to purchase 115% of their peak load capacity in the capacity market (Chow & Brant, 2017, p. 5).	The market is run by the non-profit California Independent System Operator (CAISO), which covers up to 80% of the state (London Economics, 2014, p. 47). US pioneer in deregulating its electricity market and unbundling its three major utilities in the 1990s (London Economics, 2014, p. 47) The state divested 44% of its generation assets in 1998. Retail choice was initiated in 1996/1998 and suspended in 2001 during the Western power crisis (Morey & Kirsch, 2016, p. 19). Locational marginal pricing was implemented in 2003 – went from three zones to 3,000 system nodes (London Economics, 2014, p. 60) CAISO has ability to procure capacity if reliability is not achieved the Resource Adequacy program (London Economics, 2014, p. 50)	Value chain has many companies that are owned by large vertically integrated investor owned utilities. Wholesale energy prices were found to be similar to a model of perfectly competitive market (DMM, 2016, p. 4) Approximately 70% of generation needs are met by in-state generation, with imports from Arizona and the Pacific Northwest (London Economics, 2014, pp. 47-49) Transmission cost recovery authorised by ISO Board of Governors, subject to regulatory approval (California ISO, 2017, p. 4)	As of August 2017, renewables account for 29% (excluding 12% large hydro) of the total installed capacity in the California ISO region. Solar and wind make up 9.3% and 10.4% of total installed capacity, respectively (California Energy Commission, 2017). California is ahead of its schedule for achieving its Renewables Portfolio Standard Targets (excluding large hydro), 33% of retail sales by 2020 and 50% by 2030. By 2030, 60% of electricity will be obtained from renewable sources and by 2045, 100% of electricity will be sourced from renewables (Hansen, 2017) (Leon, 2017).	The total estimated wholesale cost of serving load in 2016 was about AUD$9.3 billion or about AUD$43 /MWh. This represents a decrease of about 9 percent from about AUD$46 /MWh in 2015, mainly attributed to a 9% fall in natural gas prices in addition to sustained growth in solar generation replacing pricier generation during peak hours, and low congestion rates during most intervals. Wholesale avg. day-ahead energy prices decreased dramatically in q1 2017 from AUD$44 /MWh in Q4 2016 to AUD$29 /MWh in March 17. This is mainly attributed to increased renewable penetration to meet load and lower demand. Despite increased renewable generation from 2015 to 2016 overall frequency of extremely high or low prices in the real-time market remained relatively stable and low (DMM, 2016, p. 95). Price spikes between price floor and cap of - AUD$188 to AUD$1250 /MWh[7] (Department of Market Monitoring, 2017)		California is well-interconnected to several regional electricity markets, including the Pacific Northwest and the Southwestern US (London Economics, 2014) Cost of congestion is reflected in the cost of electricity prices (London Economics, 2014, p. 62). CAISO identifies and develops transmission solutions based on reliability, public policy and economic needs	Customers are benefiting from lower cost energy with the occurrence negative pricing events from increased penetrations of renewables (Department of Market Monitoring, 2017).

[6] http://www.caiso.com/Pages/TodaysOutlook.aspx#Power%20Mix%20by%20Fuel%20Type
[7] https://www.caiso.com/Documents/Apr4_2016_CaliforniaISO_Comments_Notice_ProposedRulemaking_PriceCaps_ISO-RTOMarkets_RM16-5.pdf

Electricity market & Market context	Regulatory context	Value chain	Renewable penetration	Pricing volatility and absolute price levels	Contract market	Signal for investment in new transmission	Customer benefits
Denmark Zonal Market (2 zones) Often imports energy from other Scandinavian countries when wind generation is low Denmark population of 5.7 million Nodal network across Scandinavian and Baltic countries – Denmark has two bidding areas defined by transmission constraints Power may be purchased on the spot price market or day ahead market.	Full retail market contestability since 2003 (Morey & Kirsch, 2016, p. 10). Danish Energy Regulatory Authority controls prices and conditions in the energy sector (Kleist, 2016).	The largest generators are DONG Energy and Vattenfall (Swedish government owned).The Danish Council previously ruled that DONG foundation company Elsam abused its dominant position in the market in 2005-2006 to alter the price of electricity (DONG Energy, 2016). The transmission system is owned and operated by Energinet, which is a subsidiary of the Danish Ministry of Climate and Energy (Energinet, 2017). Electricity is distributed through 71 Danish electricity grid companies (Danish Energy Regulatory Authority, 2015). Retailers decreased from 113 to 49 with retailer contestability – moderately concentrated retail market (Morey & Kirsch, 2016).	56% of domestic electricity is supplied from renewable sources, consisting of 41.8% wind energy and 1.8% solar energy (Danish Energy Agency, 2015). Target for 50% of power generated by wind by 2020 and 100% of electricity demand to be met be renewable sources by 2035. Plans to be completely fossil free by 2050 (Greenpeace, 2014).	In the spot price market, 95% of electricity sold during the last year falls in the range of AUD$18 /MWh to AUD$73 /MWh[8] (Nord Pool, 2017). In the day ahead market, 95% of electricity sold during the last year falls in the range of AUD$27 /MWh to AUD$57 /MWh. Minimum price cap for the day ahead market is -$750/MWh and maximum price cap is $4500/MWh[9] (Nord Pool, 2014).		HVDC link between Germany and Denmark recently upgraded to improve reliability of 600MW link (Statnett, Fingrid, Energinet.DK, Svenska Kraftnat, 2016). This upgrade was funded by Energinet.dk. HVDC link between Denmark and Sweden to be upgraded to improve life and reliability (Statnett, Fingrid, Energinet.DK, Svenska Kraftnat, 2016). This upgrade was funded by Svenska Kraftnat. Capacity of interconnection in Nordic system will increase by 50% by 2025, including interconnection to the GB (Statnett, Fingrid, Energinet.DK, Svenska Kraftnat, 2016). This transmission line will be jointly funded by National Grid, Energinet and the European Union through the Connecting Europe Facility (National Grid & Energinet, 2017).	
GB Single pricing zone There are two main power exchanges in GB – N2EX and APX. Both N2EX and APX feature day ahead and spot price markets. N2EX spot price has a single clearing price from marginal price setting similar to other markets. APX matches blind bids and offers from buyers and sellers for each hourly period. Power may be purchased on the spot price market or day ahead market. Population of 63.8 million	Full retail market contestability since 1999 (Morey & Kirsch, 2016, p. 10) The energy regulator in GB is the Office of Gas and Electricity Markets (Ofgem). Ofgem dictates the maximum amount of revenue companies can recover from users during price control periods (Ofgem, 2017).	Seven power generation companies have market shares exceeding 5%, with the three largest companies supplying 48% of all electricity consumed (European Commission, 2014). Across GB, there are three different private onshore transmission network owners which operate in distinct regional zones. Several private distribution networks operate in different regions (European Commission, 2014). In 2012, there were 12 domestic and 24 non-domestic suppliers active in the retail market. The market is characterised by six large vertically integrated suppliers, who accounted for approximately 83% of the market in 2017. Concluded to have a moderately concentrated electricity retail market (Morey & Kirsch, 2016, p. 11)	27% of power generated in GB is from renewable sources. Approximately 16% of power generated is from wind or solar resources (Office of Gas and Electricity Markets, 2017). GB's targets going forward are vague, with expectations that they will not meet their target of 30% renewable energy generation by 2020 and further targets complicated by their exit from the EU. Future goals are stated as a reduction in carbon levels, rather than a specified renewable energy generation percentage (UK Parliament, 2016).	On the spot price market, 95% of electricity sold during the last year in the N2EX market falls in the range of $53.7/MWh to $96.1/MWh (Nord Pool, 2017). In the day ahead market, 95% of electricity sold during the last year in the N2EX market falls in the range of $58.8/MWh to $96.4/ (Nord Pool, 2017). The average price for electricity sold on the APX spot market during the last year is $71.70/MWh[10] (EPEX SPOT, 2017). The average price for electricity sold on the APX day ahead market during the last month is $68.8/MWh (EPEX SPOT, 2017).	Electricity trading can occur bilaterally or on exchanges (Ofgem, 2017). There are markets for energy and capacity. The two main power exchanges in GB are APX and N2EX (European Commission, 2014). Historically, half of the electricity consumption in GB has not been traded on an exchange (Ambrose, 2015).	GB has interconnection to Ireland, North Ireland, France and the Netherlands. Plans are in place for several more interconnectors to be constructed between GB, Ireland and continental Europe (France, Belgium, Norway and Denmark) (Ofgem, 2017).	Impressively high annual customer switching rate of 18% in gas and electricity markets (Morey & Kirsch, 2016, p. 11)

[8] Prices converted from DKK to AUD using a conversion rate of 1DKK:0.2AUD as at 31 August 2017
[9] Prices converted from EUR to AUD using a conversion rate of 1EUR:1.5AUD as at 31 August 2017
[10] Prices converted from GBP to AUD using a conversion rate of 1GBP:1.63AUD as at 1 September 2017

Electricity market & Market context	Regulatory context	Value chain	Renewable penetration	Pricing volatility and absolute price levels	Contract market	Signal for investment in new transmission	Customer benefits
Ireland Single Electricity Market (SEM) provides electricity to consumers in Ireland and North Ireland Dependent on importing energy Population of 6.6 million people	Full retail market contestability since 2000 (Morey & Kirsch, 2016, p. 10). A single electricity market (SEM) operates for Ireland and Northern Ireland and is managed in dual currencies by the EirGrid Group (SEMO, 2017). Different regulatory authorities exist for the Republic of Ireland (CER) and Northern Ireland (UREGENI).	Privately owned generation. The transmission system operators for Ireland and Northern Ireland are both part of the EirGrid Group, which is owned by the Irish government (EirGrid Group, 2017). The transmission line is owned and upgraded by ESB Group, which is 95% owned by the Irish Government (ESB, 2017). The distribution system operators are ESB networks, which are a state owned company (ESB Networks, 2017). Highly concentrated retailer market providing limited retail options to customers (Morey & Kirsch, 2016, p. 11)	In 2015, 24.8% of Ireland's electricity demand was met by non-dispatchable renewable sources (primarily wind) (Trading Economics, 2015). Ireland has committed that 40% of electricity demand will be met by renewables in 2020, incorporating 37% wind power, however, it is not anticipated that Ireland will meet this target (Schoofs, 2014; O'Donoghue, 2017).	Due to the high penetration of gas in the Irish network, the system marginal price is closely correlated with the price of gas. As the penetration of wind increases, the market is increasingly influences by the availability of wind power (EirGrid, 2013). EirGrid has limited available data for historical pricing. A small pricing snapshot in October and November 2017 showed average prices of \$77 /MWh with peak prices reaching \$135-195 /MWh[11], however, this may not be indicative on an annual basis.	Electricity generators with a capacity greater than 10MW are required by law to sell electricity through the SEM. They may receive payments based on capacity, energy supplied and transmission constraints. Generators are required to bid into the SEM the day before, however, renewable energy generators are guaranteed a minimum reference price through a feed in tariff (Schoofs, 2014).	EirGrid are currently investigating numerous interconnection opportunities, including an additional line between Northern Ireland and Ireland, as well as a line between Ireland and France (EirGrid Group, 2017).	
New Zealand Full nodal network with 52 grid injection points and 196 grid exit points for reflective pricing for generators, while applying a uniform price for loads. Approximately 39000 GWh/year consumption (Electricity Authority, 2016) Over 70% of New Zealand grid connections have a smart meter (Electricity Authority, 2016). Population of 4.69 million people	Full retail market contestability since 1994 (Morey & Kirsch, 2016). The New Zealand Electricity Authority acts as the market administrator and oversees \$7 billion of transactions per year.	Over 200 generators provided power to the grid, and are mostly owned by five generation companies (Electricity Authority, 2016). The transmission network is owned and operated by Transpower, a state owned enterprise and there are 29 private distribution companies throughout the country (Electricity Authority, 2016). There are over 30 retailers for consumers to buy power from, however, the market is dominated by five major companies (Electricity Authority, 2016). Financial transmission rights protect wholesale market participants from half hourly variations in the spot market prices at various nodes. Gentailers compete for customers on a nationwide basis (Electricity Authority, 2016).	Approximately 80% of New Zealand's energy demand is met by renewable energy sources, with 5% of total generation from wind, 57.1% from hydro, 16.2% from geothermal and 1.7% from biomass (Electricity Authority, 2016; Ministry of Business, Innovation & Employment, 2015). 2025 Target of 90% renewable energy generation (Frykberg, 2016).	Prices on the spot market are calculated at each node every half an hour. As such, it is difficult to quantify the absolute prices expected throughout the system. At one reference node, the average price of electricity this year is AUD\$65.3 /MWh[12] and 95% of electricity is purchased below \$167.8/MWh (Electricity Info, 2017).	Electricity is traded on the spot market and the hedge market. In the hedge market, buyers may negotiate directly with sellers to trade on an over-the-counter contract or may buy contracts on the Australian Securities Exchange market (Electricity Authority, 2016).	New Zealand currently has interconnection between the north and south island. As part of continuing transmission line upgrades, Transpower funds a number of projects throughout the country, including interconnection of North Taranakie to the rest of the grid (Transpower, 2017).	

[11] [11] Prices converted from EUR to AUD using a conversion rate of 1EUR:1.5AUD as at 3 November 2017
[12] Prices converted from NZD to AUD using a conversion rate of 1NZD:0.9AUD as at 1 September 2017

Electricity market & Market context	Regulatory context	Value chain	Renewable penetration	Pricing volatility and absolute price levels	Contract market	Signal for investment in new transmission	Customer benefits
Singapore Day-Ahead Market introduced in 1998 13,667 MW of installed capacity (NEMS, 2016, p. 18)	Full retail contestability to be introduced in 2018. Energy Market Authority (EMA) is the independent regulatory body with no asset ownership, regulates transmission and distribution and ensures reliability by setting service standards, ensuring reliability of service and non-discriminatory access. Energy Market Company (EMC) is the market operator	13 Generator participants comprising of state and private companies (NEMS, 2016, p. 4), market share of the three largest generation companies fell below 57.7 percent in 2016 (NEMS, 2016, p. 39). Generators paid half-hourly dispatch price at 65 injection nodes (NEMS, 2016). Transmission and distribution operated by SP Power Assets with regulated revenues. 16 retailers in the NEMS, market share of three largest retailers dropped to 39.1% (NEMS, 2016, pp. 1-4). Retailers pay Uniform Singapore Energy Price (USEP); a wieghted avg. of nodal prices at all 793 off-take nodes (NEMS, 2016, p. 6).	0.24% of solar PV Generation[13] Singapore has committed to meet 5% of expected peak 2020 electricity demand with solar generation (EDB Singapore, 2017).	Min and max Market Network Node (MNN) price gap typically around AUD$9 /MWh[14] but widens when security constraint limit is reached. MMN decreased from AUD$9,300$/MWh in 2015 to AUD$93 /MWh in 2016 (NEMS, 2016, pp. 30-31) The Power System Operator (PSO) implemented security constraints in 2015 and continued them in 2016 (NEMS, 2016, p. 30). A historical low of AUD$59 /MWh was achieved in 2016 due to excess supply being 30% and lower fuel oil prices (NEMS, 2016, p. 1). The monthly USEP in 2016 ranged between AUD$41 to AUD$82 /MWh. The USEP reached prices around AUD$930/MWh several times over the year (NEMS, 2016, p. 29).	In 2003 the value of total retail settlements was AUD$2.4m compared to AUD$1M bilateral contracts (NEMS, 2003).	Investments in new entrant generation risks oversupply on the National Electricity Market Singapore resulting in the PSO applying security constraints (NEMS, 2016, p. 30)	793 withdrawal or off-take nodes that are used as the basis for prices paid by customers (NEMS, 2016, p. 6) Hedging contracts available to commercial and industrial consumers via Electricity Futures Market Retail contestability limit lowered to 200kWh for customers

[13] https://www.ema.gov.sg/statistic.aspx?sta_sid=20140802NEeM2zyMguvz
[14] Singaporean dollar to AUD = 0.93

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