A-Lab Innovation Frame 4: 'Adapting the Grid for a Decarbonised Future' – Research Context

The backbone of our power system, the Australian National Electricity Market is now the largest geographically-interconnected grid system in the world. Its 40,000 km of transmission lines and hundreds of thousands of kilometres of distribution networks transmit almost 200TWh of electricity each year from generation facilities around the country to industrial, commercial and residential customers.

Major social and technological trends at all levels – including new technologies, new behaviours and new operational challenges - are changing our requirements of the grid today. The planning, augmentation, operation and remuneration of the grid will need to be adapted to accommodate increasing amounts of renewable generation.

This research document is intended to provide background information and supporting evidence for the relevant opportunities, barriers and issues related to the topic of A-Lab's Innovation Frame 4 – *adapting the grid for a decarbonised future*. This includes a review of International and Australian experiences of solutions to overcome these barriers.

This document covers three main areas:

- Background: What are the key changes that are driving a need for action in relation to this Innovation Frame?
- Areas for innovation: What are the key innovation requirements and what must change/be implemented for the future state described in the Innovation Frame to be realised?
- International and Australian experience: What are some examples of how these issues are being addressed in other markets, or in Australia?

1. Background

The traditional electricity grid involved electricity generated at scale in large thermal and hydro facilities, then being transmitted in one direction over long distances via high-voltage cables to substations and then fanned out in distribution systems to supply end users. The large generation facilities delivered power at the appropriate voltage and frequency through synchronous alternating current generators directly coupled to the network under the oversight and control of a central market operator.

By contrast, we are now moving to a mix of large- and small-scale renewable and non-renewable resources that transmit electricity via a highly 'intelligent' electricity grid catering to multi-directional power flows and enabled by digital technologies – which also influence or directly control consumers' loads per their preferences and/or commercial signals. Renewables connect to the grid indirectly through DC-AC inverters and their output varies due to their environmental conditions; creating additional challenges in maintaining power quality.

Significant renewable energy deployment will be needed to both satisfy Australia's power demand and meet international climate commitments. Large-scale renewable energy uptake in Australia is currently primarily driven by the Renewable Energy Target (RET), which requires 33,000 GWh to be sourced from renewable sources by 2020.

The deployment of renewable energy as part of the progression towards a decarbonised future creates specific requirements to adapt the grid as we currently understand it, including:

- Maximising the utilisation of current grid infrastructure
- Financing new grid development in an era of increased uncertainty
- How do we short term forecast and operate, and by whom?
- How do we forecast & plan for the longer term?

2. Areas for Innovation

i. Optimising utilisation of existing grid infrastructure

A huge amount of money has been invested by Australians to develop our electricity grid. The total regulated asset base (RAB) of NEM-connected network service providers at the end of 2015 was around $73.6 billion.[1] This is being slowly paid off by all consumers through their network charges. This infrastructure can and should play a vital role in accessing and distributing energy from large scale renewable energy generators, as well as enabling customers to extract more value from the distributed energy resources they choose to deploy behind the meter. There are, however, several challenges related to the 'stranding' or, more likely, sub-optimal utilisation of grid assets in a future world with increased large-scale and decentralised renewable generation. These include:

- repurposing existing investments in grid infrastructure that are no longer needed due to the changing generation profile and location of renewable energy resources
- distributed energy resource-facilitated ***load*** or ***grid*** defection resulting in the fixed costs of grid infrastructure being passed through fewer units of electricity sold (and thereby making those units punitively expensive – and encouraging more consumers to opt away from the power network altogether).

i) Repurposing existing infrastructure

Australia's renewable energy target, international climate change commitments, as well as the ageing fleet of its fossil fuel generators, is likely to result in the eventual closure of large fossil fuel generation capacity. This process is already underway with recent closures including Hazelwood in Victoria, Northern Power in SA and Wallerawang in NSW. Leading generator owners have publicly indicated that further coal plants are likely to be closed at some point soon (e.g. Engie phasing out ownership of coal fired generators; AGL closing all fossil fuel generation by 2050[2]). Future policy signals, incentives or cost reductions may trigger further renewable deployment and speed up the process.

This has serious impacts for thermal asset owners, the grid system and local communities. There has been a substantive discussion around 'stranded assets' in the traditional fossil fuel industries, particularly after the Paris climate agreements.[3] Grid assets face a similar challenge. Perfectly serviceable high voltage cables and substations may be stranded due to markets or technological evolution, and the debt incurred to build them remains. While NSP's are currently sheltered from the financial risk of asset stranding within the national electricity rules and via connection agreements, the costs of these unused assets still represent an inefficiency within the energy system.

If new, renewable energy resource-driven grid investments were to be made, there is a billion-dollar question to be addressed regarding the existing infrastructure. Can it be repurposed? As one of the more expensive components already in place at these sites, there may be opportunities to repurpose

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[1] Grant, H. "Assets or Liabilities? The Need to Apply Fair Regulatory Values to Australia's Electricity Networks" ResponseAbility (2016)
[2] http://www.afr.com/news/politics/agl-dumps-coal-fired-electricity-by-2050-20150417-1mneky
[3] http://www.lse.ac.uk/GranthamInstitute/faqs/what-are-stranded-assets/; https://theconversation.com/why-stranded-assets-matter-and-should-not-be-dismissed-51939

the grid connections for cleaner fuel plant, e.g. biomass[4]. Alternately, can wind or solar facilities be sited where high voltage lines currently exist (even if these are not necessarily the optimal sites for the plant)? Looking beyond the technological element of the challenge, what opportunities would this present for the local communities, which have often become highly concentrated on the thermal energy industries of the twentieth century? Port Augusta (SA) provides a good local example, where a plan is in place to repurpose two decommissioned coal-fired power plants to make place for 6 solar thermal plants and 95 wind turbines.[5]

ii) Load defection

As the electricity grid continues to modernise, distributed energy resources (DER) such as solar PV, smart inverters, battery storage, controllable loads and electric vehicles can help facilitate the transition to a smarter grid. Specifically, these smaller sources can be aggregated to meet regular demand and reduce grid congestion, delay network investment or offset peak prices. However, the more distributed generation installed behind the meter can provide for localised demand, the less power is both required from and transmitted through the grid, reducing asset utilisation against forecasts. This is generally referred to as load defection.

If the electricity is passed between meters, network charges are incurred that remunerate grid investments. Any electricity produced and consumed within consumers' homes does not incur network charges – but not all homes are appropriate for domestic generation. As the grid adapts, policymakers should seek to minimise the impact on consumers unable to install DER (because they otherwise would bear a disproportionate percentage of the costs of connecting all customers).

As of January 2017, there were over 1.6 million PV installations in Australia, with a combined capacity of over 5.7GW, with a monthly output of approximately 600GWh[6]. The cross-subsidy impact of the reduced grid consumption by solar PV customers on the remaining customer base has been estimated at approximately $3.7b[7].

iii) Grid defection

In some instances, grid defection, or permanently islanding from Australia's main electricity grids is beginning to make economic sense. This is typically fringe of grid communities, or consumers in remote communities where advances in renewable based micro-grid technology and behind the meter distributed energy resources support increased reliability, reduced cost (or subsidies) and lower environmental impact.

In urban areas, recent customer surveys and media reports on grid defection indicate customers as less driven by fundamental economics. They are more concerned with ensuring reliability and avoiding blackouts, as well as securing control over prices in the mid- to long-term.[8] With recent comments from SA Power Networks[9] indicating expectations of a combined solar and storage cost of 15c/kWh within 10 years, this raises the prospect of further defection, unless customers perceive greater value from grid connection.

With either load or grid defection, the fixed cost of electricity supply per unit of energy delivered by the grid increases. If this becomes too 'onerous', or contributes to raising the retail tariffs of electricity further above the costs of producing and consuming electricity off-grid, more consumers are likely to

[4] http://www.power-technology.com/features/featureconverting-coal-plants-are-the-environmental-rewards-worth-the-investment-4718614/
[5] http://www.repowerportaugusta.org/
[6] http://pv-map.apvi.org.au/analyses

[7] Grattan Institute, Sundown Sunrise, 2015, p18.

[8] https://onestepoffthegrid.com.au/blackout-sparks-demand-boost-consumers-seek-reliability-solar-battery-storage/

[9] http://reneweconomy.com.au/s-a-network-says-solar-plus-battery-storage-to-cost-just-15ckwh-40898/

defect. While new cost reflective network prices being introduced by network service providers attempt to address this issue, the impact may be limited in the short term by customers' willingness to opt-in, lack of advanced meter technology, and the reliance on retailers to pass though the specific tariff designs.

Key innovation questions:

1. How can we best utilise the transmission infrastructure accessing retired fossil fuel generators?
2. What innovations would help to optimise the value of the existing grid infrastructure for consumers and act to reduce the drivers or adverse impacts of load and grid defection? e.g. electric vehicles, grid-based distributed energy markets, community energy business models. How can these innovations be progressed?
3. Are more cost reflective network prices sufficient to address cross-subsidies inherent in the current approach? How can they be most effectively implemented, while minimising adverse consumer impacts?

ii. Ensuring appropriate future grid investments in an era of increased uncertainty

Grid investments represent expensive, long-term strategic decisions that are not taken lightly. The planning process and stakeholder involvement for major grid investments require long lead times and planned new grid assets regularly face challenge on siting and land-related issues.

The areas for innovation include:

- ensuring appropriate grid interconnection in the face of very high capital costs with uncertain returns in the fast-changing generation and technology markets
- an approach to the funding of new connection infrastructure that supports economical access to areas with high levels of natural renewable energy potential but limited or no grid infrastructure
- appropriate support for electric vehicle grid infrastructure to ensure available infrastructure enhances competition and customer access.

i) Grid interconnectors

Jacobs' 2016 report for the Clean Energy Finance Corporation found that large amounts of interconnection are required in the NEM by 2030, with up to 3,500MW of additional interregional capacity – the clear majority of it to enable distributed renewables.[10] UNSW had previously estimated that the additional interconnectors foreseen would add an approximate annual cost of $1.6 – $3.9 billion to customer bills.[11] Although it is also worth noting that the falling cost of battery storage and solar PV might offset much of this cost by smoothing localised demand and reducing the need for specific interconnectors. Furthermore, the Federal and Tasmanian governments' feasibility study into a second interconnector between Victoria and Tasmania indicated a capital cost of between $800 million and $1 billion.[12]

All network costs are ultimately passed on to the end-consumers. In the absence of a mechanism that considers the environmental or emissions reductions benefits of connecting renewable energy

[10] http://www.cleanenergyfinancecorp.com.au/media/222968/benefits-of-transmission-upgrades-in-a-transforming-electricity-sector.pdf
[11] UNSW, Least cost 100% renewable electricity scenarios in the Australian National Electricity Market, 2014
[12] https://www.environment.gov.au/system/files/energy/files/preliminary-report-feasibility-of-a-second-tasmanian-interconnector.pdf

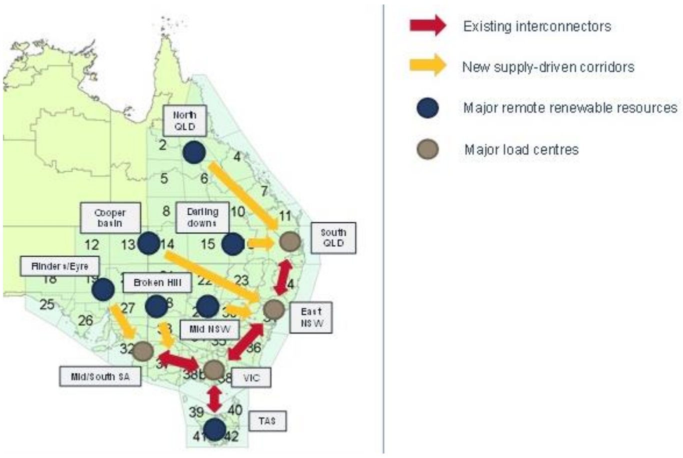
explicitly, the costs of additional inter-state interconnectors may prove prohibitive. Investors will reallocate capital into another sector that offers either more competitive returns or less risky investments unless they foresee predictable, sustainable returns – whether these are regulated or market-derived.

ii) Accessing new areas of renewable energy resource

Australia has significant renewable energy potential – both in terms of solar irradiance and consistent, smooth wind speeds. Australia's solar resources are generally located in more remote areas of the country and wind resources concentrated along the coast. However, the power grid in this country was not built with renewable potential in mind. Instead, transmission and distribution assets were deployed to connect thermal and hydro power stations (usually sited adjacent to their fuel source, such as the coal-rich Latrobe Valley) with our major industrial and residential nodes. The creation of the National Electricity Market (NEM) led to the physical interconnection of the respective grids of different Australian states and territories – but again did not reflect renewable energy potential.

Renewable energy potential does not align with existing large-scale grid assets. An AEMO report[13] into the implications of Australia moving towards 100% renewables highlighted this misalignment, as shown in Figure 1.

Figure 1 – RE resources and existing and required high-voltage transmission assets



Source: AEMO

As it stands, proponents of new large scale renewables projects are required to pay for the assets required to connect their project to the grid - with the greater the distance, the greater the cost. This creates a significant disadvantage for first-mover proponents looking to develop renewable generation capacity in areas not currently close to the existing network.

The trade-off between the cost of the connection asset and access to areas with high natural renewable energy potential may result in renewable generation being deployed in suboptimal locations. There have been recent attempts to generate innovative ways to share the cost of the connection between renewable generator developers. This includes TransGrid's proposed Renewable Energy Hub in New England NSW, which would be purposely 'over-sized' to facilitate future connections.[14]

iii) Grid infrastructure for electric vehicles

Finally, there are some concerns about the lack of appropriate grid infrastructure impacting EV uptake or that, if left to commercial infrastructure developers, available EV charging infrastructure may stifle competition or lead to the excess deployment of capital and replicated assets. There are relatively

[13] AEMO, 100 Per Cent Renewables Study, November 2013
[14] https://www.transgrid.com.au/news-views/blog/Lists/Posts/Post.aspx?ID=47

few EVs in Australia today, but to increase the numbers, grid operators may need to make network upgrades and capacity additions to handle large charging loads in specific locations at peak times. Hence it may be appropriate to consider a more planned approach to EV infrastructure deployment.

Plugging a high-performance electric vehicle into a Tesla 'fast charger' (for example) is roughly equivalent of adding several houses' demand to the grid in a particular location. In the future, might every household that currently owns an internal combustion engine want to charge their cars? In parts of the US, this has been recognised as a forthcoming challenge, with PG&E and other Californian utilities already involved in distribution-driven substation and feeder upgrades.

Key innovation questions:

1. How can investments in grid infrastructure to connect regions be de-risked?
2. How can the costs of connecting new renewable generators be managed ensuring that the sites with best long term potential are considered by developers?
3. Could a more planned approach to EV infrastructure support increased uptake and competition, and reduced cost?

iii. Operating the grid

System operators co-ordinate the supply and demand for electricity and manage power quality in real time. The NEM has traditionally been conceived as generators, transmission network service providers (TNSPs), distribution network service providers (DNSPs), electricity retailers and end-users, all administered by the Australian Electricity Market Operator (AEMO).

Distributed renewable energy penetration is challenging this set up. Critical system operational functions – specifically dispatch, grid security and reliability - historically performed by transmission-level entities, are now required at the distribution level. This means DNSPs might be required to become or manage multiple distribution system operators (DSO) or distributed energy market operators. Decentralised operating entities will need to be better informed on the immediate fluctuations of a myriad array of decentralised PV installations or a flotilla of connected household batteries. There is likely to be a requirement for renewables ad enabling technologies (such as storage, or aggregated demand response) to provide frequency support and system balancing services. Operating entities could then control and/or trade with these resources at the distribution level, satisfying demand and ensuring power quality.

This trend poses interesting questions about the devolution of risk and control. What will be the role of the DNSP in the future that requires detailed distribution system operation functions? Do they have the right systems and staff? Are the correct economic incentives in place for this transition? How are DSOs set up to communicate effectively with TNSPs and other system operators? And foundationally, does this transition deliver operational benefits?

Looking further out, some commentators suspect that the ultimate "smart grid" with smart distributed energy resources (both supply and demand) will have an inbuilt, machine-learned emphasis on autonomy. In real terms, this might be as simple as a smart meter protecting domestic appliances from grid power surges. At a more advanced level, a vast network of smart devices at all levels could route and re-route electrons to preserve grid stability, maintain voltage and perform all the traditional roles of system operators using high speed data analytics and electronic controls[15]. The PSERC Future Grid report (2016) stresses the importance of "real time, lightweight and adaptive algorithms for…

[15] For further discussion of highly distributed gird operation and control see A-Lab's research context paper for Innovation Frame 3 – *creating the internet of energy*

measurement and monitoring, and communication, [which are] responsive to grid dynamics and support various applications…”[16] and then, will human operators be needed at all?

Key innovation questions:

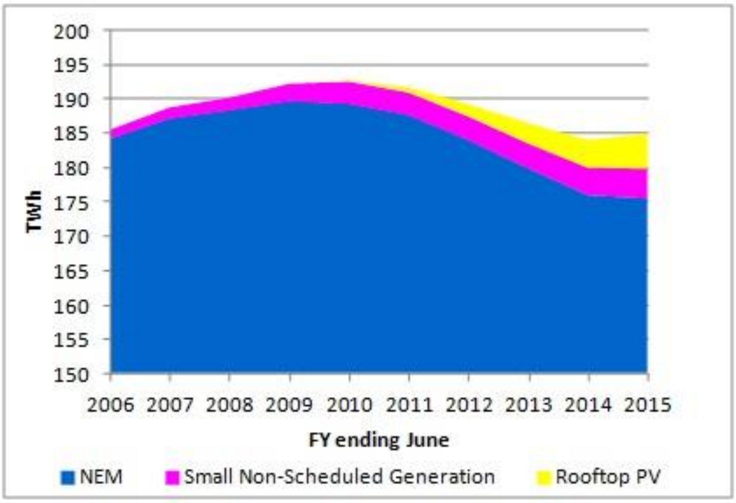
1. How can we explore the role and relationships between TNSPs and DNSPs in operating a high DER system?
2. What is the optimal network area within which control should be centralised? At the nation, state, distribution zone, substation, feeder, etc.? How could we test this?
3. Can a complete grid be successfully operated without human intervention? What would be needed?

iv. Forecasting and grid planning

Grid-level power demand forecasting was traditionally a centralised function of anticipated population and economic growth, adjusted for relative economic energy efficiency. This top-down figure is then compared with more detailed geospatial analysis from distribution businesses of load profiles, expected industrial developments, etc.

Figure 2 shows how these expectations have been disrupted since around 2007/08. Specifically, and despite population increase and a slow post financial crisis economic recovery, total energy use and energy use per capita have fallen – from the NEM and in total – implying increases in energy efficiency, increasing DER use and/or behavioural change. While the changes occurred out of sight of the power system, they have had major implications for the grid’s operation and development, and therefore for sectoral forecasting and planning.

Figure 2 – Total energy demand and per capita consumption over time (NEM, non-scheduled production and solar PV)



Source: AEMO, 2015 National Electricity Forecasting Report, Energy Efficiency Council[17]

AEMO used to use historical bulk transmission data as their primary source for future forecasts. However, this historical data lacked detail as it was highly aggregated, is not indicative of a changing future and does not reveal social and economic trends happening beyond the grid. In fact, it was the forecasting equivalent of driving by looking in the rear-view mirror.

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[16] https://pserc.wisc.edu/documents/general_information/PSERC-Future-Grid-brochure-May-2016.pdf
[17] http://www.eec.org.au/news/efficiency-action/efficiency-insight-may2016

In response to the inaccuracies of the persistent growth forecasts that their methodology was showing AEMO has adopted new data streams in 2016, including granular consumer energy meter data and complimentary data from exogenous sources on the state of the economy and wider trends.[18]

Planning, in contrast, traditionally involved assessing supply options to meet that electricity demand. This consisted of the generation stack already available to system operators, plus power stations and interconnectors in the immediate pipeline. Just ten years ago, load shedding agreements or other demand management techniques were 'worst case' scenarios.

Today, the planning side of the demand-supply equation has also changed fundamentally. Grid systems face significant challenges in terms of the economic availability of thermal generation (as it has been displaced in the merit order by highly variable but very low marginal cost renewables), as well as the penetration and aggregation of storage and other DER technologies. Commercial and industrial units now enter complex contractual arrangements to drop demand loads at specific price points.

The grid needs to adapt to these new realities. Systems and staff are needed that can process the volumes of data emanating from smart devices, interconnected substations, complex irradiance and wind speed forecasts and turn these into robust, reliable and transparent business case decisions for future network grid planning.

Key innovation questions:

1. How can demand forecasting better reflect the speed of modern technology and social change?
2. How do we balance planning the requirement for long term assets with the speed of short-term change?
3. Are we forecasting and planning over the right horizons, and if not, what would be better?

[18] http://www.aemc.gov.au/About-Us/Panels-committees/Reliability-panel/NER-panel-requirements/ Report-on-demand-forecasts-for-the-NEFR-2016.aspx

3. International and Australian experience

i. Improving network planning and reducing risk on returns: Australia's Network Opportunity Maps

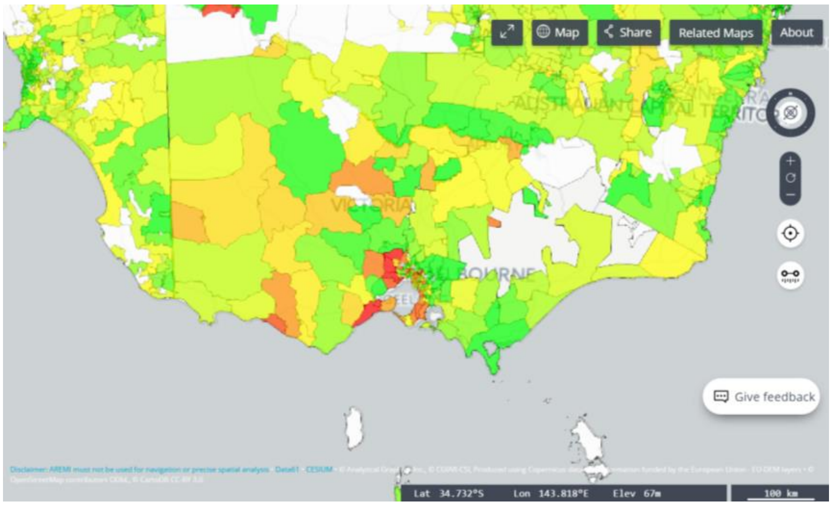
One of the core challenges in adapting the grid lies in knowing what to build, where. Electricity network data is highly complex and specialist experience is required to decipher it. Accessible, consistent data on constraints, costs and avoidable investments helps encourage transparency, challenge and diversity in network planning.

ARENA supported the University of Technology Sydney's Institute for Sustainable Futures to lead the development of interactive, colour-coded Network Opportunity Maps (NOMs) of Australia's electricity grid. The free, publicly available Australian Renewable Energy Mapping Infrastructure (AREMI)[19] charts the most valuable locations for investment in renewable energy and demand management across the grid.

Specifically, the map consolidates the expected availability across electricity distribution zones based on network planning report data, highlighting areas in the grid where future electricity demand is expected to outstrip supply. The maps facilitate NSPs', non-network aggregators' and DER vendors' understanding of the likely value created by reducing peak power demand in different places.

While the underlying data sets are regularly updated with annual network data, the increasing penetration of smart devices in the network could potentially even mean these could be updated in near real time in the future.

Figure 3 – Network Opportunity Map of Available Distribution Capacity in Victoria (screenshot)



Source: Institute for Sustainable Futures, Australian Renewable Energy Mapping Infrastructure

[19] http://nationalmap.gov.au/renewables/

ii. Financing interconnection: America's merchant transmission

As in Australia, the optimal renewable resources in the USA do not align with either the populous power demand centres or existing grid systems. The concept of a nation-wide transmission overlay in America has been discussed for some time.

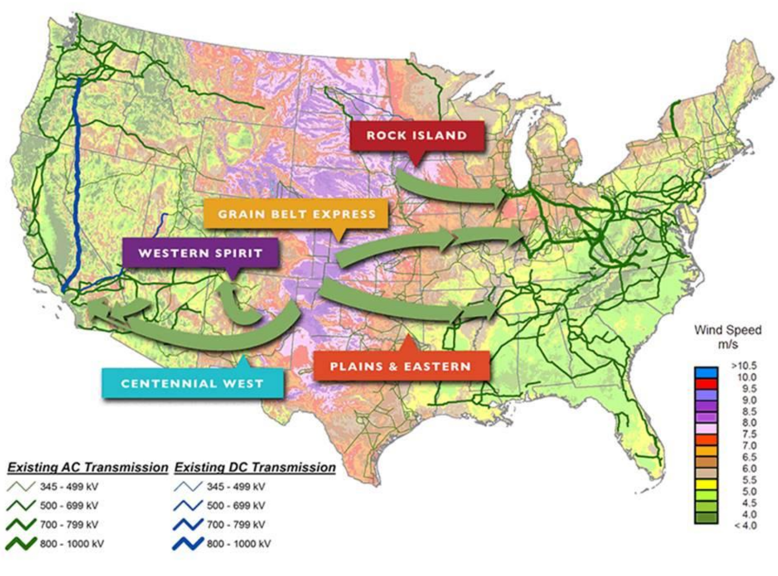
The foundation is a high-capacity, long-distance transmission grid that connects all three current network systems into a single integrated system and facilitating the siting and growth of renewables and other power sources. Recent research demonstrates a potential cost-reduction of between $250 billion and $500 billion over its 40-year operational lifetime, while promising to increase operational flexibility and infrastructure resilience.[20]

However, it has been widely assumed that limited future demand growth makes financing any upgrades for aging transmission challenging, and the lack of a federal carbon tax or renewable mandate is making it difficult to integrate renewable generation in general. A core assumption was that high-voltage transmission lines of this scale would need to be treated as regulated assets to be financeable.

Three recent announcements have challenged that – all of which stem from *merchant* transmission providers looking to arbitrage renewable energy prices:

1. The 2,000 MW high voltage direct current (HVDC) 'Southern Cross' project to move wind from Texas's highly-penetrated market to South-Eastern US markets.
2. The Plains & Eastern 'Clean Line', a $2 billion, 705-mile, 4,000 MW transmission system is moving to construction, connecting Oklahoma wind to the South-Eastern US grid system.
3. The 'Grain Belt' 780-mile, $2 billion, HVDC line could deliver 4,000 MW of Kansas wind to the midcontinental (MISO) grid system.

Figure 4 – Proposed transmission projects to shift inland wind to load centres on the USA coasts; overlaid on wind speed data



Source: Clean Line Energy Partners *(Also showing the older Western Spirit, Centennial West and Rock Island planned lines. Not shown: Southern Cross line)*

How could merchant lines be encouraged in Australia? What could be learned from the US experience in how to bring these proposals forward?

[20] Y. Li, Design of a High Capacity Inter-Regional Transmission Overlay for the U.S. (IEEE Transactions on Power Systems, 2015)

iii. Reducing network upgrade costs and increasing deployment speeds: Germany's offshore wind connection process

Before 2013, German offshore wind developers' grid connections were legally guaranteed to be provided by the relevant (nearest) TSO. The TSO in charge of the connection of North Sea wind farms faced severe technical challenges in providing the grid connection and this caused significant delays to the roll out of wind projects, as well as to cost inefficiencies in connecting each wind farm individually, wherever it may be sited.

Since 2013, however, German TSOs draw up an annual Offshore Grid Development Plan (O-NEP), which they submit to the Federal Network Agency (BNetzA). This has replaced the developers' automatic rights to connections with an objective, transparent and non-discriminatory procedure that allocates and develops transmission assets that are shared across individual wind farms. The costs of the network deployment are spread across the customer base.

While Australia is at the other end of the spectrum (requiring renewables developers to finance their own grid connections), could a similar process be applied here? Could consortia of renewable energy project developers work with TNSPs to submit network investment cases to the AEMO and government?

iv. Project finance: developers de-risking grid upgrades

If rigorously analysed and properly planned, grid upgrades offer long-term, stable investments – ideal for the world's pension and sovereign wealth funds. However, given the risks, major funds need proactive guidance and advice.

Siemens, the German technology conglomerate, focuses on the opportunities arising from electrification, automation and digitisation. It founded the Siemens Financial Services (SFS) in 1997, a market-facing investment arm to help manage Siemens' risks, but also to offer credit, leasing and alternative forms of asset and equipment financing as well as project financing and equity options.

SFS is now taking equity positions in projects to transform Europe's grid network. For example, SFS contributed 20% of the €2.8 billion Gemini project's total equity and in so doing, helped de-risk the project and attract the remaining investors. Could the methodology of technology partners taking equity positions to reduce the cost of project finance be applied to Australian network upgrades?

v. Improved grid connection: UK Power Network's plug-and-play

One example of improving the connection process for larger generators is UK Power Networks' Flexible Plug-and-play project, a 3-year project partially funded by Ofgem's Low Carbon Networks Fund, which trialled new innovative ways to offer customers discounted and faster connections to constrained sections of the distribution network.

The customer in turn must agree to having its generation interrupted at the discretion of the NSP in the event of the network being constrained. According to UK Power, these customers saved more than 70% on their connection cost.

UK Power Networks stressed the importance of customer engagement in getting customers to sign up, both in terms of explaining and selling the concept and an ongoing relationship to manage the curtailment and related customer interaction.