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6 August 2021

Ms Felicity Sands
Manager, Gas Reform
Department of Environment, Land, Water and Planning

Dear Ms Sands

Victoria's Gas Substitution Roadmap

The Australian Energy Market Operator (AEMO) welcomes the opportunity to comment on the *Victoria's Gas Substitution Roadmap Consultation Paper* regarding transition pathways to net zero. AEMO's submission is attached.

Having operational and planning roles for both gas and electricity infrastructure within Victoria, AEMO has a strong interest in the outcomes of this consultation process.

AEMO's submission primarily focuses on:

- The transition pathways, sector coupling and modelling,
- Technical system requirements and impacts such as storage and minimum demands, and
- Energy system (gas and electricity) reliability during the transition.

Other areas, such as industrial workforce planning, typically fall outside of AEMO's remit and would be better addressed by asset owners and industrial groups.

In summary, AEMO supports the further development of policy and regulatory frameworks to deliver a safe and reliable supply of energy for Victorian customers in the long term, at an efficient cost.

Should you have any questions or wish to discuss AEMO's submission, please contact

Yours sincerely

Tony Chappel

Chief External Affairs Officer

Attachment: AEMO Submission on Victoria's Gas Substitution Roadmap Consultation

AEMO: SUBMISSION ON VICTORIA'S GAS SUBSTITUTION ROADMAP CONSULTATION PAPER

1. Executive summary

AEMO supports the further development of policy and regulatory frameworks to deliver a safe and reliable supply of energy for Victorian customers in the long term, at an efficient cost.

AEMO believes many of the pathways identified by *Victoria's Gas Substitution Roadmap Consultation Paper* are complementary, and a combination of pathways will be needed for Victoria to achieve a net zero energy system across the electricity, gas and transport sectors at the least cost. There are opportunities across each of the identified pathways that may present least cost options to address specific needs.

In the following analysis and discussion, AEMO recommends:

- Future modelling of the impact of electrification of current gas loads to also consider the electrification of transport, both battery electric and hydrogen fuel cell electric vehicles.
- Investigation of the added impacts of increased electrification on requirements for inertia, frequency control, and system strength across the power system.
- Actioning options first which are more clearly optimal and economic across multiple pathways, in areas such as improving energy efficiency, shifting load away from peak times, and supporting the uptake of storage.
- Presenting an indicative schedule for several of the pathways (developed by working backwards from key decarbonisation milestones), to highlight when decisions need to be made to allow for an orderly transition.

AEMO also notes:

- Integrated energy system modelling is appropriate to determine the potential pathways towards net zero, including all primary energy sources and considering interactions between all sectors (industrial, commercial, residential, energy, agriculture, land use, and transport). In addition, when modelling the electrification of gas use, instantaneous flows not daily quantities need to be used.
- Approximately half of Victoria's large commercial and industrial gas use is unlikely to be able to be electrified, meaning that hydrogen or biogas would need to be used to replace natural gas. The cost of replacing commercial and industrial gas equipment with electrical equivalents also needs to be considered against the use of hydrogen or biogas.
- If gas use declines substantially, the impact of network costs on remaining gas customers and the investment and cost recovery impact on gas network owners need to be considered.
- Increased electrification and increased variable renewable energy (VRE) generation will result in an increased requirement for energy storage, including shorter-term technologies through to long duration inter-seasonal storage.
- Hydrogen's role in the power system will result in an increased coupling between the electricity and gas sectors, ranging from power system demand management through to zero emissions power generation.

2. Overview analysis

2.1. Decarbonisation pathways and modelling

AEMO believes that integrated energy system modelling, which includes all primary energy sources, is most appropriate to determine the potential pathways towards net zero.

The transition to net zero is an extremely complicated process and the modelling should consider the interactions between all sectors – industrial, commercial, residential, energy, agriculture, land use, and transport. If modelling is conducted for individual sectors in isolation, it could lead to conclusions which do not consider broader sector interactions.

For example, if modelling examines only the gas sector transition, it might conclude that the natural gas load could be electrified with few upgrades to the electricity grid. A separate set of modelling examining the transition to electric vehicles may also come to the same conclusion. However, when considered together, the combined impact may require substantial electricity network augmentations to maintain a secure and reliable supply.

AEMO delivers a range of forecasting and planning publications for the east coast energy system, including the *Electricity Statement of Opportunities* (ESOO), *Gas Statement of Opportunities* (GSOO), *Integrated System Plan* (ISP), *Victorian Annual Planning Report* (VAPR), and *Victorian Gas Planning Report* (VGPR).

Over the last 10 months, with significant industry consultation[1], AEMO has prepared an *Inputs, Assumptions and Scenarios Report* (IASR) which contains key scenarios and relevant data which will be used for all AEMO forecasting and planning reports. For the current suite of inputs, assumptions and scenarios[2], AEMO models five scenarios and a notable sensitivity[3]. Four of these scenarios show various pathways to net zero carbon emissions by 2050.

To establish interactions across the various energy sectors, AEMO has been working in collaboration with CSIRO and ClimateWorks Australia to explore the results of their multi-sectoral model. Biofuels, hydrogen and electrification are all seen to play a role in AEMO's scenarios and key sensitivity to a varying degree. For example, even in the Strong Electrification sensitivity, biofuels and hydrogen are seen as required technologies for long haul transport, aviation, and some industrial applications.

These inputs will be assessed in the Draft 2022 ISP to determine the impact on the electricity system.

2.2. International decarbonisation and transition plan modelling

Many international studies have been conducted examining potential transition pathways to net zero and the required technologies to achieve it. The IEA *Net Zero by 2050*[4] roadmap for the global energy sector is one such study, which talks about the key pillars for decarbonisation as:

[1] https://aemo.com.au/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-assumptions-and-scenarios

[2] https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios

[3] The Strong Electrification sensitivity explores a future with strong decarbonisation ambitions, similar to the Hydrogen Superpower scenario, only the hydrogen cost savings do not eventuate, putting more pressure on the electricity system.

[4] https://www.iea.org/reports/net-zero-by-2050

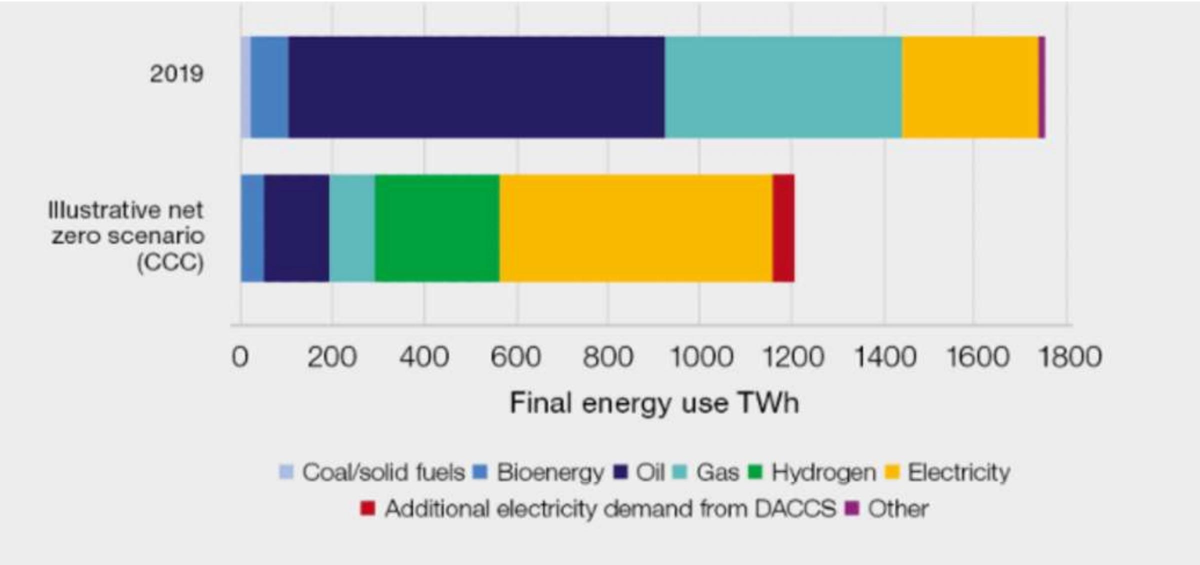
- Energy efficiency.
- Behavioural change.
- Electrification.
- Renewables.
- Hydrogen and hydrogen-based fuels.
- Bioenergy.
- Carbon capture and storage.

When considering what role each of these pillars may play, the IEA report says that each will play a different role in different sectors (transport, buildings/heating, industry/feedstock, and electricity), but also notes that it will differ by region depending on the region's requirements. For example, it notes that in cool climates with high building heating loads, it expects "*low-carbon gases, including hydrogen-based fuels, remain significant in 2050 in regions with high heating needs, dense urban populations and existing gas or district heat networks*."

When comparing between roadmaps for different jurisdictions or countries, it is important to compare to regions with similar energy usages. In Australia, Victoria has a significantly larger building heating load than any other jurisdiction, making it difficult to compare to other Australian states. When looking internationally, the most relevant comparisons would be to some European countries, such as Germany and the United Kingdom (UK).

In December 2020, the UK published an Energy White Paper[5] about transitioning the country to net zero. The analysis, which accounted for emissions and energy use from households and industry, through to transport and land use, produced an anticipated energy mix as shown in Figure 1.

Figure 1 Current and modelled UK final energy use for 2050



Source: Energy Trends table 1.2; CCC Net Zero Report

[5] https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future/energy-white-paper-powering-our-net-zero-future-accessible-html-version

As Figure 1 shows, in the UK total energy use is expected to drop substantially due to energy efficiency gains. There is a large increase in electricity usage due to the electrification of a large portion of the natural gas and oil consumption, however, hydrogen is also identified as playing a major role in the fuel switching away from fossil fuels in the residential, industrial and transport components. The hydrogen produced is a combination of green hydrogen from renewables and blue hydrogen from natural gas steam methane reforming combined with carbon capture and storage.

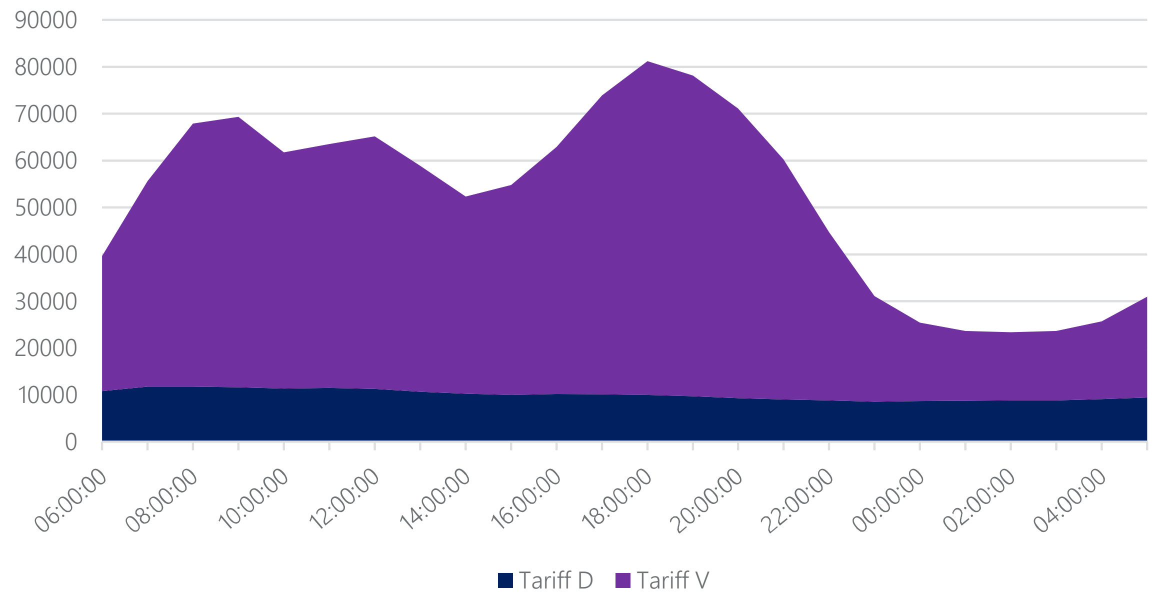
As noted in both the IEA and UK roadmaps, all these technologies will be required to achieve net zero across all sectors that use energy, and align very well with all the pathways identified in *Victoria's Gas Substitution Roadmap Consultation Paper*.

2.3. Gas load characteristics

The natural gas load in Victoria can fluctuate significantly throughout the year, with seasonal, daily, and intraday variations. For example, in 2020, the demand for gas in Victoria (excluding that consumed by gas-powered generation [GPG]) varied significantly from as high as 1,208 terajoules (TJ)/day down to as low as 229 TJ.

On low demand days which typically occur during the Christmas period, the load is primarily industrial, while on high demand days, which typically occur during winter, the load is primarily residential heating.

Figure 2 Declared Wholesale Gas Market (DWGM) demand, 4 August 2020 (GJ/hr)



As shown in Figure 2, the gas consumed within a day also varies significantly, from as low as 24,000 gigajoules (GJ)/hr up to as high as 81,000 GJ/hr. Hourly gas system demand has exceeded 80,000 GJ/hour five times in the last five years, and not always on the peak demand day. Due to the temperature profile, which can vary significantly throughout the day, the average daily system demand for these five days was only 1,045 TJ. This is well below the typical forecast 1-in-2 peak demand day. When looking at options to convert this natural gas load to a net zero energy supply, it is critical to look at the peak hourly requirement and understand the components of existing natural gas usage.

Determining what this might look like as an electrified load is complex and requires many assumptions, including:

- The efficiency of existing natural gas appliances[6,7] currently installed throughout Victoria.
- The proportion of the load that is Tariff V (residential and small commercial) versus Tariff D (large commercial and industrial).
- The hourly proportion of residential demand that is for heating, hot water and cooking.
- The coefficient of performance (COP) of heat pumps that can be achieved for the electrification of residential heating[8] and hot water.
- How current commercial and industrial customers are using natural gas.
- The proportion of industrial load that cannot be electrified.

2.3.1. Residential and commercial gas use (Tariff V)

To fully electrify residential and commercial gas consumption would also require substantial additional electricity supply that would need to be generated, transmitted, and distributed. Balancing these requirements is a non-trivial exercise, and assessing the future electricity supply-demand balance is the purpose of the ESOO in the short term and the ISP in the longer term.

For Victoria, the maximum gas demand is predominantly driven by residential and commercial customers, mainly for heating, followed by hot water, and then cooking. The dominant role of heating in gas consumption in Victoria makes the demand strongly seasonal, with a peak winter day demanding as much as five times as much gas as a typical summer day, on top of the substantial variability within the day discussed above and shown in Figure 2.

When modelling the electrification of gas heating load, it is critical to model hourly and within hour gas flows to understand the possible implications on peak electricity demand, including how fast a peak winter period demand ramp-up could occur. Modelling conducted at an annualised or daily level, is likely to miss the implications of heating load electrification. The 2021 ESOO is explicitly exploring the impact of varying electrification of gas load, and key assumptions and scenarios are in the 2021 IASR. However, the granularity of the individual hourly data discussed above is not broadly available.

The Draft 2022 ISP, due to be published in December 2021, will also consider the influence of various fuel switching options. Given the extent of gas consumption in Victoria, electrification of the residential gas load would result in Victoria's peak electricity demand moving from summer to winter, while full electrification could result in the need for a significant increase in electricity transmission and distribution capacity. Previous reports[9] have found that the increase in demand may be significant, and AEMO is undertaking further work in this area.

While renewable gases, such as hydrogen and biomethane, may not be as cost-effective today, they may present viable options to utilise the existing gas distribution infrastructure and reduce the need for new electrical infrastructure expenditure.

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[6] https://www.elgas.com.au/blog/449-star-ratings-for-gas-heaters-gas-wall-furnaces-a-gas-fireplaces/

[7] https://www.energyrating.gov.au/sites/default/files/documents/Product_Profile_Gas_Ducted_Heaters.pdf

[8] https://renew.org.au/wp-content/uploads/2018/08/Household_fuel_choice_in_the_NEM_Revised_June_2018.pdf

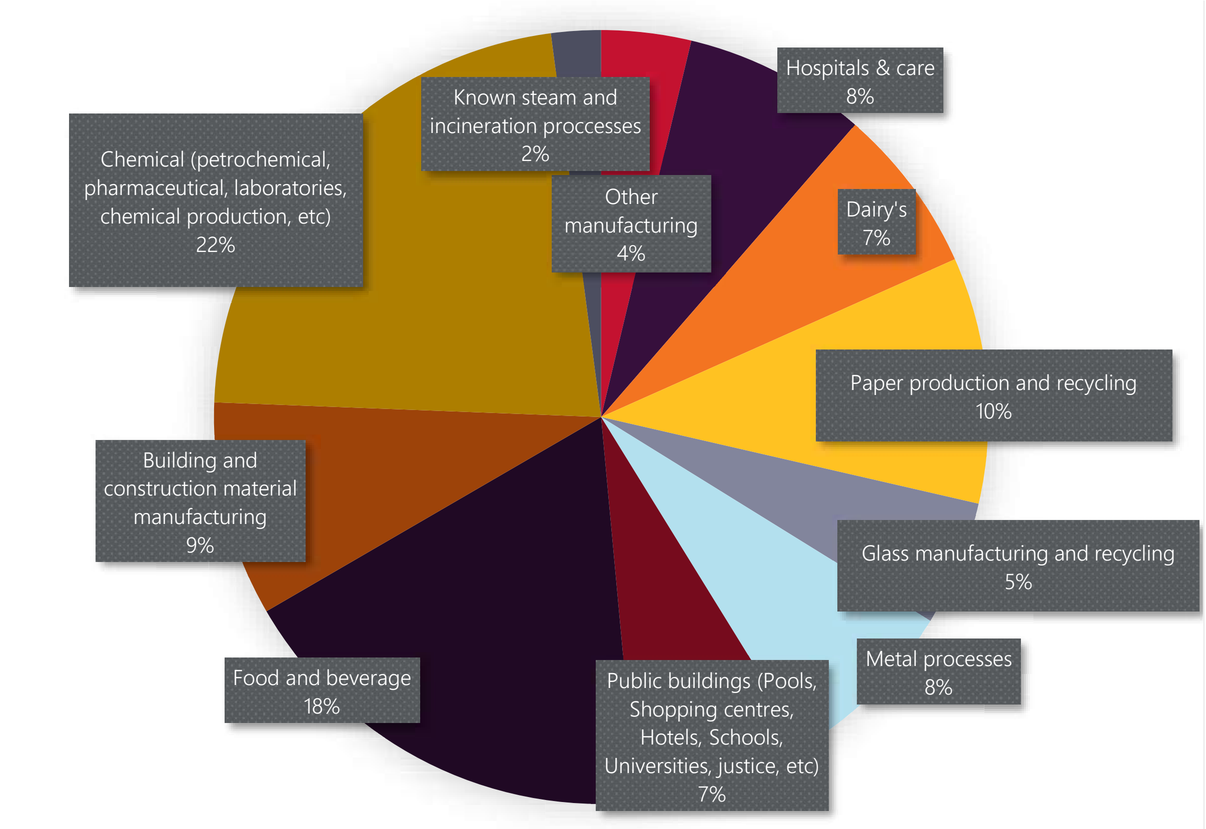
[9] https://www.energynetworks.com.au/resources/reports/decarbonising-victorian-gas-consumption-australian-gas-infrastructure-group/

2.3.2. Industrial gas use (Tariff D)

For industrial (Tariff D) consumers, the calculation is a little more involved, with more data needed and fewer assumptions possible. Industrial consumers use natural gas for a range of purposes, with different options for fuel switching. While low temperature applications such as space heating and water heating may be a viable option for electrification, higher temperature applications and chemical feedstock applications would be very difficult or impossible to directly electrify; these will likely need a molecular/chemical energy source, such as biomethane or hydrogen.

Figure 3Figure 3 shows the current breakdown of Victorian Tariff D usage.

Figure 3 Victorian Tariff D usage by category



As noted in the *Gas Substitution Roadmap Consultation Paper*, electrification with heat pumps is not expected to occur for processes which require temperatures greater than 250°C or which use natural gas as a feedstock. This covers the petrochemical industry, glass manufacturing/recycling, metal processes (such as recycling, smelting, and galvanisation), building and construction material manufacturing, and known incineration processes. These categories cover 47% of Victoria’s Tariff D gas usage by consumers.

For the remaining 53%, mixed factors will determine whether current uses of gas could be electrified and the scale of such electrification. ‘Type B’ gas appliances used by industry are customised complex gas installations that use more than 10 megajoules (MJ) per hour of gas. This makes it difficult to determine their aggregated efficiency, what an electrical load equivalent is, or whether the use can be electrified at all. Some Tariff D usage, however, involves space heating and water heating by consumers – such as hotels, schools, swimming pools and shopping centres – which could be electrified with heat pumps similar to the residential load.

Based on the Victorian Tariff D usage breakdown, the 47% of Victoria's Tariff D load for which electrification is unlikely sets a baseline minimum requirement of approximately 112 TJ/day or 40 petajoules (PJ)/year, assuming that hydrogen or biogas is used to displace the natural gas usage for high temperature and chemical feedstock purposes, and that these industries continue operating in a net zero Victoria.

Further work is required to determine what components of the paper industry, dairy industry, and general food and beverage industry can be electrified with industrial heat pumps, due to the significantly varying processes used by each individual customer.

It is important to note that this is a technical discussion regarding what gas usage can be electrified, and does not include economic or commercial considerations. While it may be technically possible to electrify or fuel switch some of these loads, the upfront capital costs or ongoing operational costs may not be commercially viable for some industries.

2.3.3. Network utilisation

A key point to note regarding the electrification of load is that as load is removed from the gas networks, the cost of operating the gas networks will be passed onto fewer and fewer consumers while the total cost of operating the networks is unlikely to proportionally reduce. Over time this could significantly increase the costs of molecular/chemical energy to consumers who require it, such as the 47% of industrial consumers described in Section 2.3.2.

While economic modelling may suggest that an electrification initiative results in least cost outcomes for the energy sector overall, the impacts on industrial sectors and possible consequences should be fully considered.

As a future piece of work, it is worth identifying the minimum number of consumers needed on a gas network to avoid exposing particular industries to additional cost pressures and whether the rate of allowable depreciation of gas network assets should be increased as part of an electrification pathway.

2.3.4. Other fossil fuel use

Other fossil fuel sources may also need to be converted to low emission energy sources if their emissions are not negated or offset. A notable example is LPG used for heating and hot water in rural communities without mains natural gas connections, and LPG used for cooking throughout Victoria, for example, in barbeques. Another is petroleum-fuelled machinery including generators, chainsaws, lawnmowers and similar equipment. Some of these processes lend themselves to electrification and some do not. Electrification of this energy use will further increase the electrical load above the estimates for the electrification of gas use and should be included in any over-arching review.

2.4. Storage requirements

Currently, Victoria's gas network plays a vital role in providing dispatchable energy, both in the form of direct heating via the gas distribution system and in dispatchable electricity via GPG supplying the NEM. All future pathways for the gas system must consider how this role will be met, both during the transition and at the ultimate end point.

As Australia's energy system transitions towards net zero, AEMO expects significant increases in VRE to meet Australia's energy requirements. One challenge identified from this is the variable nature of VRE and how NEM demand will be supplied during periods of low VRE generation output.

Storage is expected to play a significant role in meeting these requirements, however different types of storage may be used for different purposes, as discussed in the 2020 ISP[10]:

- Shallow storage, which includes technologies such as lithium-ion batteries and flywheels, is small-scale storage that is more about providing fast ramping and frequency control than providing a continuous supply of energy. These shallow storage needs could also be partially met by demand response (industrial or virtual power plants [VPPs]). Technologies which cover the shallow storage requirements of a net zero energy network (batteries and flywheels) are fairly well developed and are expected to be easily integrated as required.
- Medium storage, which can be supplied by very large-scale batteries or pumped hydro, allows intra-day shifting of energy demand, typically within a 4-12 hour timeframe.
- Deep storage is large-scale energy storage which must be able to supply for long periods to cover extended periods of limited VRE and provide seasonal smoothing (inter-seasonal storage, where energy is stored in one season and used in another when it is needed). Economic low-emissions options for deep storage are currently limited to large scale pumped hydro, due to the limited range of mature deep storage technologies.

Currently in Victoria, the natural gas supply chain covers the same storage categories:

- The Victorian Gas Declared Transmission System (DTS) acts as medium storage by using natural gas stored in the pipelines (referred to as "linepack") to supply the morning and evening demand peaks, which is then replenished outside of the peak demand periods, typically overnight.
- Iona Underground Gas Storage (UGS) provides deep storage to cover the peak winter period, and is then replenished during the lower demand summer period.

As shown earlier in Figure 2, gas demand varies significantly throughout the day while supply stays relatively constant. DTS linepack is used to manage this imbalance.

Table 1 shows the order of magnitude of energy storage available from existing or planned Australian facilities or technologies.

It is also important to consider the dispatch capacity, response time, and ramp rate of each storage type. Batteries as shallow storage can rapidly ramp up or down and discharge their stored energy within hours. Larger facilities, such as underground gas storage, cannot ramp or respond as quickly; however once they are discharging/generating, they can supply energy for weeks or months at a very high rate, characteristic of seasonal shifting. Pumped hydro is somewhere in the middle.

A combination of storage types is essential, as they all play very different roles.

[10] https://www.aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en

Table 1 Existing and planned energy storage

Facility / technology	Energy storage (MWh)
Tesla Powerpack 2	0.20
Toyota Mirai hydrogen tank	0.22
Hornsdale Power Reserve Battery (and expansion)	129 (up to 193.5)
Victorian Geelong Big Battery (under construction)	450
Dandenong LNG tank	182,000
Victorian Gas Declared Transmission System	233,000
Snowy Hydro 2.0 (planned)	350,000
Iona Underground Gas Storage	6,371,000

Below, AEMO discusses the storage implications of two different pathways.

2.4.1. Strong electrification pathway

The 2020 ISP modelled the deep storage requirements for the NEM out to 2040 based on ~15 gigawatts (GW) of coal-fired generation still remaining in the NEM and a gas transition consistent with the GSOO. The ISP did not model extensive fuel switching, yet even without extensive fuel switching, the modelling already indicated significant quantities of deep storage being required to cover low VRE periods, especially in the low solar period of winter (see Figure 4).

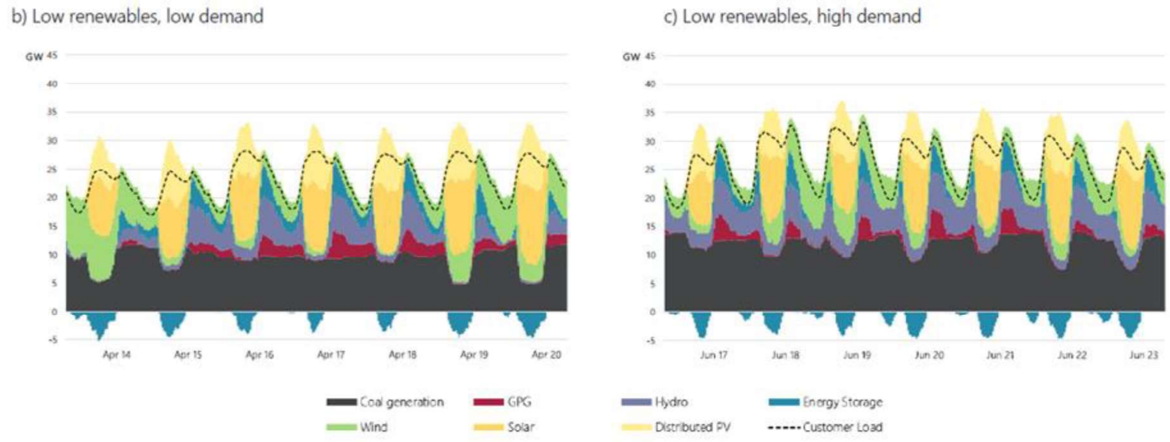
Figure 4 Deep storage balancing energy throughout the year in 2035

Source: 2020 ISP.

With the inputs and assumptions AEMO has since revised, the Strong Electrification sensitivity modelling is expected to show an increase in electrification, an increase in required VRE, and therefore an increased required volume of deep storage. Timing of this transition will also be important, with consideration needing to be given to the carbon intensity of the electricity supplying these loads and hence overall emissions. Further work may be required to determine the optimal timing that decreases total emissions.

Figure 5 was included in the 2020 ISP, and illustrates an indicative generation mix during periods of low VRE in 2035, both at low demand and at high demand. As noted above, this did not assume significant electrification of the gas demand. It shows that a mix of energy storage (including pumped hydro and batteries) and GPG was selected by the model as the least cost option in each case.

Figure 5 Indicative generation mix in the NEM in 2035 (GW)



Source: 2020 ISP, excerpt from Figure 17.

In the electrification pathway, to achieve the long-term decarbonisation goals, the storage role currently provided by existing gas networks would need to be largely replaced by additional deep storages linked to generation (pumped hydro or hydrogen storage linked to hydrogen-fired GPG).

2.4.2. Replacement of gas with hydrogen pathway

To decarbonise the NEM further, hydrogen could potentially play another role by providing deep storage, if it can compete on a cost basis with pumped hydro.

While bulk hydrogen storage appears to be a new/developing area in Australia, there is substantial international experience. For example, the Clemens Terminal in Texas has had an operational underground hydrogen storage facility since the 1980s. This salt cavern hydrogen storage facility can hold 2,520 tonnes of hydrogen, which is equivalent to 98,000 MWh of energy storage.

CSIRO flagged hydrogen storage as an important research and development priority out of the National Hydrogen Roadmap[11] and has now commenced an Underground Hydrogen Storage in Australia[12] investigation project.

The existing gas distribution network could cope initially with a blend of approximately 10% (by volume) hydrogen, and could potentially be modified to allow up to 100% hydrogen. While research is still ongoing in this area it should be noted that town gas, that was used throughout Victoria prior to the 1969 introduction of natural gas, was approximately 50% hydrogen.

This would allow the gas distribution network asset to continue to supply distributed dispatchable power (via GPG or fuel cells) and direct heat to residences and industry (subject to appliance replacement where required). It could also act as medium term storage in its own right simply by using the available linepack within the system.

The ability to repurpose low pressure gas pipelines to provide a ready low carbon transport and storage may reduce or delay the need for expensive expansions of the existing electricity distribution system. Even if the hydrogen costs more for a single solution, it is possible that the total costs to the energy system as a whole would be lower by utilising existing gas distribution pipes that may otherwise be at risk of becoming stranded assets.

Other modifications that would be required to use high concentrations of hydrogen in gas systems would be replacement of household appliances (or their burners), and gas turbine generators. AEMO notes that the UK is currently evaluating a commitment for all new gas appliances to be 100% hydrogen-ready by 2025[13] to reduce the transitional burden.

The ability of gas turbines to generate with hydrogen does not currently exist within Australia, however EnergyAustralia[14] recently announced that the new Tallawarra B Power Station will be able to generate from a blend of natural gas and hydrogen. GE[15] also notes that it currently has 75 units across the world running on hydrogen or hydrogen blends. The question of whether existing turbines can be retrofitted to generate using hydrogen is key to understanding the economics of this pathway.

High pressure natural gas transmission pipelines may be able to transport 100% hydrogen, however there are many uncertainties regarding that form of operation and as a minimum it is expected that most pipelines would require some operating pressure derating.

APA is currently testing a section of the Parmelia Gas Pipeline[16] in Western Australia to determine its suitability to operate with 100% hydrogen. Each pipeline and its ability to transport hydrogen will vary due to the composition of the pipeline steel, any lining of the pipeline, the pipeline's maximum allowable pressure rating, and age. Work similar to the APA study will be required on Victorian pipelines to understand their potential to transport and store hydrogen.

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[11] https://www.csiro.au/en/work-with-us/services/consultancy-strategic-advice-services/csiro-futures/futures-reports/hydrogen-roadmap

[12] https://research.csiro.au/hydrogenfsp/our-research/projects/our-research-in-underground-hydrogen-storage-in-australia/

[13] https://www.hhic.org.uk/uploads/60365E39725CC.pdf

[14] https://www.energyaustralia.com.au/about-us/media/news/energyaustralia-gives-green-light-australias-first-net-zero-emissions

[15] https://www.ge.com/gas-power/future-of-energy/hydrogen-fueled-gas-turbines

[16] https://www.apa.com.au/news/media-statements/2021/apa-set-to-unlock-australias-first-hydrogen-ready-transmission-pipeline/

Any new high pressure hydrogen pipelines would act as medium-term storage through management of linepack.

In the gas replacement with hydrogen pathway, new storage would still be required for provision of dispatchable power in the NEM, but this would be significantly less than in the electrification pathway.

2.5. Minimum demand periods

In the 2020 ESOO[17], AEMO noted that minimum electricity demand periods were becoming a problem for parts of the NEM with high levels of distributed photovoltaics (PV). The ESOO noted that to maintain system strength in Victoria, various combinations of synchronous units must always remain online. Even with exports of excess energy during low demand periods, a demand threshold is required in Victoria to enable the minimum number of synchronous generating units in the state to operate at their minimum stable levels and provide the essential system services (such as inertia, frequency control, and system strength) needed to keep Victoria secure. Without action, this minimum demand threshold was projected by the 2020 ESOO to be reached around 2024, however there are scenarios where it could occur earlier.

Use of energy storage in Victoria – either in pumped hydro, the production of hydrogen from electricity using electrolysers, or underground storages – could, if installed in sufficient quantity, increase electricity demand in these minimum demand periods to the levels needed to stay above this threshold. This would enable minimum demand levels that support continuing operation of the minimum number of synchronous generating units needed to protect system security during autumn and spring (the periods minimum demand periods frequently occur).

3. Discussion of issues and challenges

3.1. Issue 1: Maintaining electricity reliability with new sources of demand

In the face of changing demand, AEMO is required to maintain both reliability (the ability to deliver sufficient power to meet consumer demand at any point in time) and security (the ability of the system to respond to and recover from disturbances and maintain quality of the power supply within required standards) in the NEM.

Developments in electricity demand are likely to impact both reliability and security of the power system.

3.1.1. Impacts on power system reliability

Section 2.3 discusses the potential increase in demand due to electrification of gas loads.

In parallel, transport may also be electrified, significantly adding to the increase in electrical load. This may occur through battery electric vehicles (assumed to be small passenger vehicles with shorter ranges for city driving) or hydrogen fuel cells for heavy haulage, longer range, rural, or high use vehicles which cannot stop for long periods to recharge (such as buses, trains, trucking, and taxis). Both of these transport options could place an increased load on the grid,

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[17] https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en&hash=85DC43733822F2B03B23518229C6F1B2

either from the battery recharging directly, or from a grid-connected electrolyser producing hydrogen.

The ability to store energy in the form of hydrogen to be transferred to the vehicle at a suitable time may assist the energy system, as this is effectively another form of storage.

It is likely that a combination of both battery electric and hydrogen fuel cell vehicles will be utilised, and AEMO recommends that future modelling of the impact of electrification on current gas loads should consider this potential concurrent change in transport requirements.

3.1.2. Impacts on power system security

The electrification of loads as envisaged in this pathway is likely to mean that the majority of load growth will occur in the distribution network. This has direct implications for future planning within the distribution networks, and may also give rise to system security issues. As discussed earlier, the recently released 2021 IASR outlines the five scenarios that will be used by AEMO in modelling the 2022 ISP, along with a range of sensitivities. These include varying degrees of electrification of load across the NEM and this work will help to inform future policy to achieve emissions targets. This is an area that AEMO and DNSPs may include in collaboration on the ISP, including the impact of the relevant scenarios on power system security.

The NEM is already facing challenges in managing system security as traditional generators retire and are replaced by inverter-based resources (IBR). Both the frequency and voltage of the AC waveform must be maintained within certain standards to ensure safe and secure operation of the NEM. Growth in demand due to electrification of gas loads may either help or hinder the management of system security as the grid evolves to meet changes in the generation fleet.

In addition, the characteristics of demand are changing as the nature of the load itself changes. Significant quantities of new loads consist of electronics, including inverters and switch mode power supplies. These are changing the load's dynamic response to disturbances, and even the power factor of the load is changing.

As the amount of synchronous generation is reduced, further measures to manage reactive support may be required, including potentially reactive support to cope with large changes in reactive power requirements from low to high demand periods. The changing nature of the load may also mean that dynamic active responses need to be considered further when assessing power system security.

AEMO is currently working to incorporate the changing system security needs by estimating requirements for inertia, frequency control, and system strength across the NEM. Further analysis will be required to investigate the added impacts of increased electrification on the NEM. It is recommended that AEMO undertakes this work in close consultation with DNSPs.

3.1.3. What policies are needed to ensure the electricity network can reliably serve new sources of demand from electrification of gas demand, hydrogen production, and electric vehicles?

AEMO agrees that each of the mitigation options outlined in the consultation paper (Issue 1) have the potential to improve management of peak electrical demand. These include load shifting, large and small-scale batteries, energy efficiency, and both centralised and distributed renewable generation, in addition to potential hydrogen use.

Both electrical distribution and transmission systems will need to adapt to the changed demand profile due to electrification of loads, so network service providers (NSPs) should be consulted on potential impacts on their networks and possible mitigation strategies.

If electrolysers are to be installed onto the network, consideration needs to be given as to where they are connected, how many are connected, and how they are controlled. There could be fewer connections from large, aggregated facilities, or there could be numerous smaller facilities scattered across the network. Each option has potential advantages and disadvantages, and further work in this area is required.

Policy aimed at incentivising EV owners to charge their vehicles during the middle of the day will help minimise the cost of additional power system infrastructure, although the impact and success of such schemes will also need to be carefully monitored, because the vehicles will not always be at charge points in the middle of the day.

The location of these charging points also needs to be considered. Charging many vehicles in an area like the Melbourne CBD could overload the existing distribution network, which may also need to supply electrified heating load.

Overnight charging is likely to rely on stored energy when wind generation output is low (and there is no solar generation).

3.1.4. What is the role for gas-fired power generation (GPG) and hydrogen in maintaining electricity reliability?

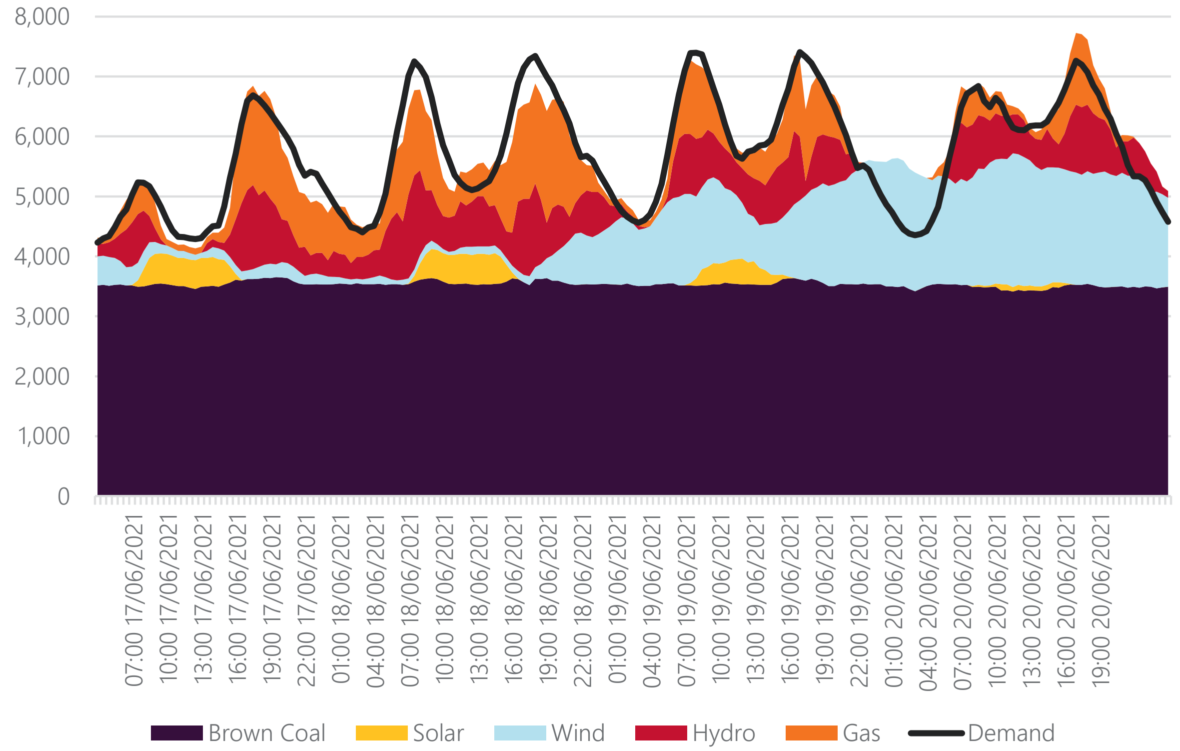
In the short to medium term, AEMO expects annual volumes of natural gas for generation to decline, due to the forecast increase of new VRE, but hourly and daily volumes to be a lot more variable.

Large flexible GPG capacities will be needed to cover low renewable periods, coal-fired generator outages, and ultimately the retirement of coal-fired generation. A substantial increase in GPG demand occurred in Victoria when the Hazelwood Power Station closed in March 2017 and in South Australia after the closures of the Northern and Playford B power stations. The 2021 GSOO[18] said, "*Higher GPG demand is frequently event -driven, and AEMO forecasts continued volatility in GPG demand, with large variances driven by the NEM's operation of coal, hydro, and renewable energy generators*."

Figure 6 shows Victoria's generation mix last winter during a lower coal generation period. The graph shows that gas played a critical role in Victoria's generation mix during a low VRE period, before ramping down to small peaking quantities as the wind increased. Electricity imports into Victoria are shown by the white space between demand and Victoria's generation mix; when the Victorian generation exceeds the black demand line, Victoria was exporting electricity.

[18] https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2021/2021-gas-statement-of-opportunities.pdf?la=en

Figure 6 Victoria electricity supply 17-20 June 2021

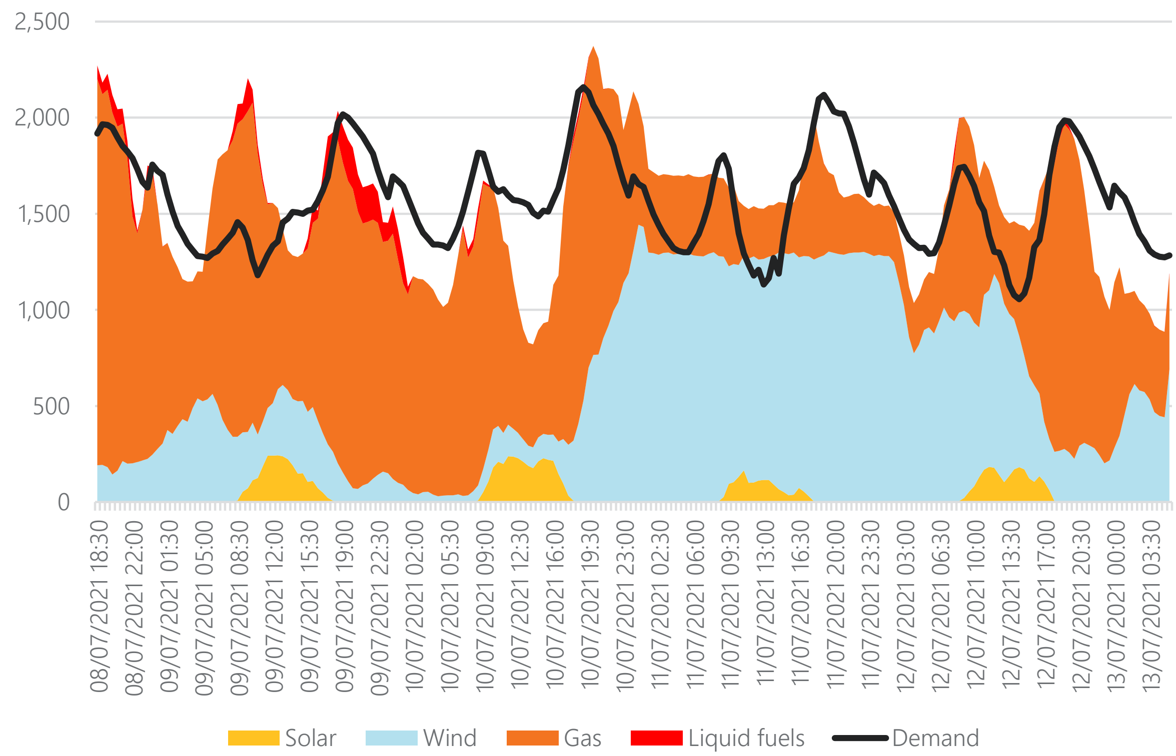


As the coal-fired generation in Victoria retires and is replaced by VRE with firming capacity, the generation mix in Victoria could look more similar to the generation mix in South Australia. Figure 7 shows the generation mix in South Australia significantly varying, between 100% VRE (with gas generation only running to provide system security services), through to very low VRE periods (where the electricity is provided by almost 100% natural gas).

In the longer term, the firming requirements of gas are expected to shrink with increased interconnection and the development of deep storage. It will be important to consider what declining gas usage in this pathway could imply for the economic viability and potential consolidation of gas assets in the longer term.

With regards to hydrogen, at this stage it is uncertain what role it might play in the NEM. It is possible that in time hydrogen could replace natural gas to provide some of the firming dispatchable generation requirements, however this is highly dependent on whether hydrogen plays a role by providing deep storage, and the more general availability and use of hydrogen in the economy, including to the extent that it develops as an export commodity.

Figure 7 South Australia electricity supply, 8-13 July 2021



3.2. Issue 2: Transitioning to more sustainable gaseous fuels with minimal disruption to end users

The transition disruption is likely to involve potential impacts to end use appliances, pipelines, and the markets and billing.

The Future Fuels Cooperative Research Centre (CRC)[19], gas network owners, gas appliance manufacturers, and Energy Safe Victoria (ESV) are better placed to comment on the first two items, due to the research they are currently conducting.

With regards to potential market impacts, AEMO presented a paper to the Gas Wholesale Consultative Forum (GWCF)[20] in April 2021 on potential impacts to:

- The Victorian retail market.
- Heating values, gas quality and billing.
- The DWGM design and operation.

Industry submissions and feedback on the paper were supportive of an investigation into how distribution-connected hydrogen or biogas facilities would be included within the DWGM, and how heating value accuracy for billing will be maintained when hydrogen is added to distribution networks.

[19] https://www.futurefuelscrc.com/

[20] https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/gas-wholesale-consultative-forum

3.3. Issue 3: Maintaining the reliability, affordability and safety of gas supply

With regards to gas reliability, there are short-term and long-term issues and objectives.

In the short term, gas supply reliability issues are now emerging due to Gippsland production declines, increased Iona UGS inventory depletion (as seen this winter) due to high GPG, lower Dandenong LNG contracting, and delays in the planning and construction of critical investments.

The 2021 VGPR[21] noted that "*The declining Victorian production capacity during the outlook period is also expected to reduce system resilience. Peak day supply capacity currently exceeds peak day demand, providing sufficient margin for the operational management of equipment trips, unplanned maintenance, and demand forecast errors. The forecast depletion of the key legacy gas fields supplying the Longford Gas Plant will result in reduced peak day capacity and this capacity margin will no longer be available. This tightening supply demand balance will result in an increased probability that operational issues are unable to be operationally managed, leading to an increased likelihood of threats to system security or curtailment events*."

AEMO also notes the findings of The Independent Review of Victoria's Electricity and Gas Network Safety Framework[22], specifically recommendations 23 and 24 relating to the potential for a gas reliability standard/framework.

In the longer term, reliability issues may be of a very different nature, with the potential for:

- Declining performance of aging gas plants as gas fields decline.
- Closure dates of gas plants if fields cease producing.
- Conventional gas supplies being replaced with a large number of distribution-connected hydrogen and biogas facilities.

As Victoria transitions to a lower emissions future, striking a balance between the investment required to prevent shortfalls and avoiding long-term stranded assets will be critical. Investments that would appear to find this balance include hydrogen-ready pipelines or assets (including GPG), investments with a low amount of required capital, or the utilisation of existing pipelines or assets where little expansion is required.

3.4. Issue 5: Managing uncertainty in the transition

The scenarios being developed for the 2022 ISP are necessarily broad at present. Key uncertainties relate to factors including:

- Electrification of both transport and stationary energy demand.
- The uptake of energy efficiency measures.
- Whether hydrogen progresses and becomes a major part of the economy or plays a fairly minor role.

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[21] https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/vgpr/2021/2021-victorian-gas-planning-report.pdf?la=en

[22] https://www.energy.vic.gov.au/electricity/electricity-network-framework-review

- The kinds of controls or incentives that might be put in place to help manage distributed energy resources (DER) – including rooftop PV, home batteries and electric vehicles – as these will play a major role in determining future system requirements and operations.

At present, all these influences are highly uncertain and lead to broadly different scenarios.

Adoption of a phased approach will help manage these uncertainties.

AEMO recommends actioning options which are more clearly optimal and economic across multiple pathways first, in areas such as improving energy efficiency, shifting load away from peak times, and supporting uptake of storage. Decisions on other aspects of the system can then potentially be delayed until there is further clarity on likely future pathways – although forward planning is also critical to allow time to factor in the long timeframes that will be required for planning and implementation of changes to the power system infrastructure.

AEMO also recommends presenting an indicative schedule for several of the pathways, developed by working backwards from key decarbonisation milestones, to highlight when decisions need to be made to allow for an orderly transition. This could include, for example, a certain number of years for phasing out old technology that may be discontinued, to allow consumers and suppliers time to adjust and factor future policies into their purchasing decisions.