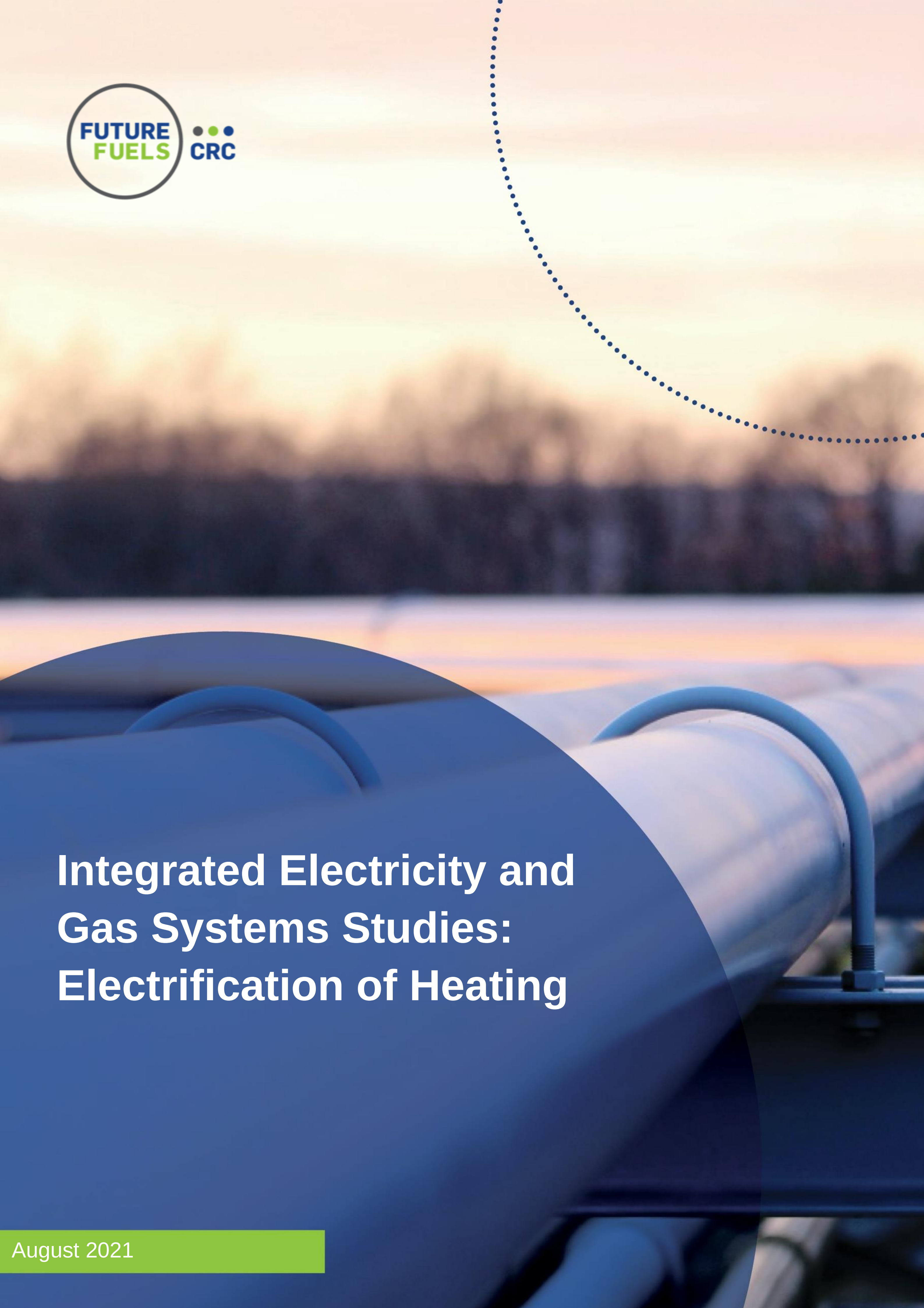

FUTURE FUELS CRC

Integrated Electricity and Gas Systems Studies: Electrification of Heating

August 2021

Project number: RP1.1-02

Regional Case Studies on Multi-Energy System Integration

Authors:

Sleiman Mhanna, The University of Melbourne

Isam Saedi, The University of Melbourne

Pierluigi Mancarella, The University of Melbourne

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IMPORTANT DISCLAIMER

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Project Leader and Team	Prof Pierluigi Mancarella (Lead), University of Melbourne Prof Michael Brear, University of Melbourne Prof Mike Young, University of Adelaide Dr. Sleiman Mhanna, University of Melbourne Isam Saedi, University of Melbourne
Industry Proponent and Advisor Team	Dr Dennis Van Puyvelde (Energy Networks Australia)
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Executive Summary

This report aims to demonstrate the potential capabilities of the integrated electricity and gas system (IEGS) modelling tool under development in conducting studies on the electrification of heating for the electricity and gas transmission networks of the state of Victoria as an initial testbed. In particular, the studies consist of assessing the *impact* of electrification of residential heating on the electricity and gas networks of Victoria, under the "Central" scenario in AEMO's integrated system plan (ISP) for the year 2025. A similar study for the year 2035 is included in Appendix C.

The electrification studies are conducted for five different cases in 2025, namely, (i) 1-in-20-year peak gas system demand day, and (ii) low-wind 1-in-20-year peak gas system demand day, (iii) average winter gas demand day, (iv) low-wind average winter gas demand day, and (v) average autumn gas demand day. Each one of the five different electrification scenarios consists of three subcases where space heating (SH) and domestic hot water (DHW) gas demands are replaced with electric options: (i) 0% SH and 0% DHW, (ii) 50% SH and 50% DHW, and (iii) 100% SH and 100% DHW. In this work, the electrification of heating is assumed to be enabled predominately by air-to-water electric heat pumps (EHPs).

The main findings can be summarized as follows:

- Without imports from NSW through Culcairn, or an increase in capacity of committed gas supplies, AEMO's forecast of the shortfall in the Victorian gas supply for a 1-in-20-year peak gas demand day manifests in an EoD linepack that is significantly lower than the BoD linepack, which is not desirable as AEMO sets a BoD linepack target that accounts for the impact of unscheduled demand from gas-powered generators (GPGs) and surprise cold weather. In extreme cases, such as two consecutive 1-in-20-year peak gas demand days, the linepack swing can drop below a value that violates minimum pressure limits, which compromises the security of the gas system.
- The generation mix of 2025 is inadequate in most electrification cases (50% SH and 50% DHW and 100% SH and 100% DHW). However, in all the electrification test cases, the Victorian part of the NEM, with the 2025 augmentations of both the Western Victoria's electricity network and the interconnectors as per AEMO's ISP, can support electrification levels up to 50% SH and 50% DHW without requiring augmentations.
- The 100% SH and 100% DHW electrification scenario involving the 1-in-20-year peak gas system demand not only shows that the electricity network of Victoria witnesses inadequate generation, but also shows that (i) some interconnectors need significant augmentation and (ii) the electricity network requires augmentation in the form of up to 220% increase in MVA (thermal) capacity on some internal transmission lines.
- The gas supply is inadequate on a low-wind 1-in-20-year peak gas demand day with 50% SH and 50% DHW case. This shortfall in the Victorian gas supply manifests in an EoD linepack that is lower than the BoD linepack. In all the other cases the gas supply is adequate, as evidenced by an EoD linepack close to the BoD linepack, which is a desirable outcome as AEMO sets both the EoD and BoD linepack targets to values that maintain efficient and safe system operational conditions.

The results from these initial studies demonstrate the efficacy of the modelling under development to support techno-economic assessments of future low-carbon scenarios and the importance of bottom-up integrated multi-energy sector, network, and system assessment with relatively high spatial and temporal resolution and suitable operating constraints, which are lacking in most if not all studies performed so far. Next steps envisage the extension of the Victorian system test case to the whole eastern gas transmission network and the National Electricity Market (NEM) transmission network. This will require extending the electricity network model to the whole NEM and the gas network model to the whole gas transmission system of eastern Australia. The data collection will be facilitated by our industry partners.

It is important to note that the findings in this report should be considered for *illustration purposes only* and in the context of the specific assumptions made herein, rather than real guidelines for market stakeholders, for which specific studies based on agreed input data and assumptions should be performed.

1. INTRODUCTION

Traditionally, electricity and gas networks have been modelled, operated, and managed separately. However, the growing reliance on gas-powered generators (GPGs) and the potential advent of clean fuels such as hydrogen are prompting a paradigm shift towards and the need for jointly modelling integrated electricity, gas, and hydrogen systems (IEGHS), to better capture the multi-energy nature, constraints, spatial and temporal inter-dependencies, and synergy opportunities of future low-carbon energy systems.

This report is part of FF CRC's *Regional Case Studies on Multi-Energy System Integration* project (RP1.1-02), which aims to develop models for analysing various case studies on the potential of different clean-fuel options for the decarbonisation of the whole energy system of Australia. Specifically, the scope includes the techno-economic assessment of integrated electricity and gas systems in light of different coupling technologies and scenarios for different sectors (e.g., injection/storage of hydrogen/synthetic methane into the gas network, production of low-carbon fuels for export, electrification vs decarbonisation of heating and transport, etc.). Case studies in different scenarios, whose data acquisition will be facilitated by the industry partners, will be conducted on one or more specific regions of interest, such as Victoria or the entire East Coast.

The report starts by detailing the data collection and the necessary steps building up to an appropriate setup for the case studies, such as identifying the relevant scenarios in AEMO's Integrated System Plan (ISP) in Section 2.1, the corresponding expansion of both the electricity and gas networks in sections 2.2 and 2.3, and updating the gas supply capacities as per AEMO's gas supply adequacy outlook in Section 2.3. The underlying algorithmic approach is described in Section 2.4 and consists of two stages. The first stage is a unit commitment model with a strengthened direct-current optimal power flow (DC-OPF) to capture network losses (particularly important at times of peak demand and in the case of electrification); this is implemented in a 24-hour time horizon with a half-hourly resolution. The second stage a transient gas flow model can captures the change in linepack across the 24hours of the day.

The gas flow model is first validated by backtesting simulated linepack profiles against actual linepack profiles from AEMO in Section 2.3. It is then used to quantify the impact of the forecast reduction in the 2024 gas supply on the linepack. Next, the modelling tool is used to conduct electrification studies that quantify the impact of the electrification of (residential) space heating (SH) and domestic hot water (DHW) demands on both the electricity and gas networks of Victoria in Section 3. The CO_2 emissions for the five electrification scenarios are estimated and analysed in Section 3.6. Finally, the report summarizes the main findings in Section 4 and discusses the implications and recommendations for the industry in Section 5. Next steps and Future work are discussed in Section 6.

2. SETUP

This section describes the setup and chronicles the underlying data collection that paved the way for compiling the set of case studies in this report, starting with AEMO's ISP scenarios, and followed by the expansion of the Victorian electricity network, the expansion of the Victorian gas network, and the Victorian gas supply outlook.

2.1. AEMO's ISP scenarios

The case studies in this report are conducted under two of AEMO's ISP scenarios, namely, the "Central" and the "Step Change" [1], for carefully selected representative days and months in 2025 and 2035. The Central scenario incorporates a 50% renewable energy target in Victoria (VRET) by 2030 and the Federal Government objective of reducing emissions by at least 26% by 2030. The Step Change is the same as the Central scenario but with aggressive uptakes of distributed energy resources (DER)[1] and variable renewable energy sources (RES)[2]. The ISP also identifies potential renewable energy zones (REZ) across the national electricity market (NEM), as shown in Figure 1, as well as the retirement plan for some coal-fired generators as shown in Figure 2.

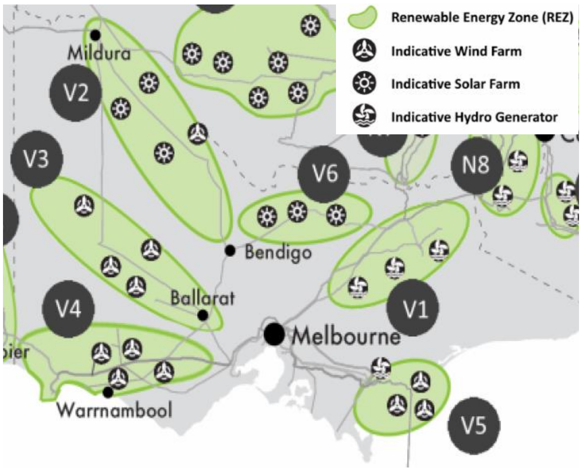

Figure 1: Identified potential REZ across the NEM [1].

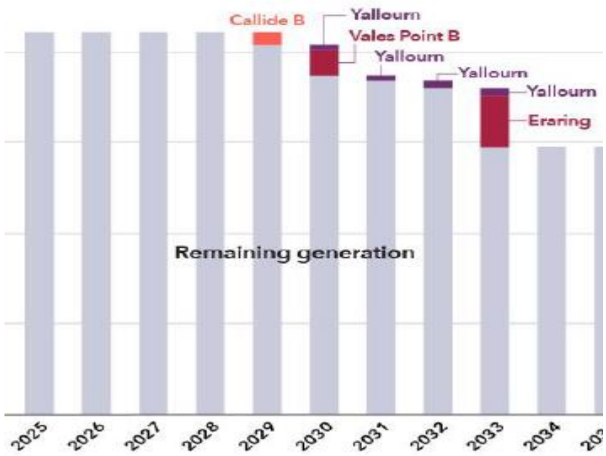

Figure 2: Retirement of some coal-fired generators [1].

As such, electricity demand forecasts and RES output forecasts for the corresponding scenarios and representative days and months are obtained from AEMO [2].

2.2. Electricity network expansion

Network data (parameters) for transmission lines, transformers, buses, and generators is acquired from [3], which is publicly available. However, the data in [3] is for 2018 and was therefore subject to modifications to reflect (i) the generation mix of 2025,[3] (ii) the augmentation of the interconnectors, and (iii) the augmentation of Western Victoria's electricity network.

The generation mix of 2025 and 2035 is updated accordingly to include REZ generation outlook, obtained from AEMO's ISP 2020 [4], and the retirement of some coal-fired generators and GPGs, obtained from AEMO's Input and Assumptions Workbook 2019 [5]. The interconnectors are also augmented accordingly for 2025 and 2035, as described in AEMO's Input and Assumptions Workbook 2019 [5]. In compliance with the REZ generation outlook in AEMO's ISP 2020 [4], the total installed wind and solar capacities in 2025 are 4150 MW and 1357 MW, respectively, for the Central scenario.[4] Finally, Western Victoria's electricity network is augmented as per the preferred option identified in the Western Victoria Renewable Integration RIT-T project report [6], as shown in Figure 3 and Figure 4.

[1] Including rooftop PV, batteries, and other resources at the customer level.
[2] Including solar and wind energy resources at the utility level.
[3] Including the REZ and the retirement of some coal-fired generators and GPGs.
[4] Utility-level battery storage in Victoria is not considered in this study for the sake of simplicity, as the total capacity of existing and committed utility-level battery storage projects is relatively small, 75 MW. Two possible new entrant batteries will have a capacity of 100 MW each. However, we do not expect that any of the results provided would change fundamentally.

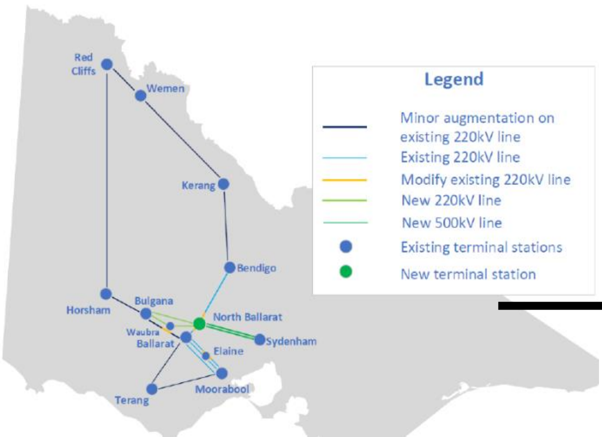

Figure 3: Preferred network augmentation option for the Western Victoria Renewable Integration RIT-T [6].

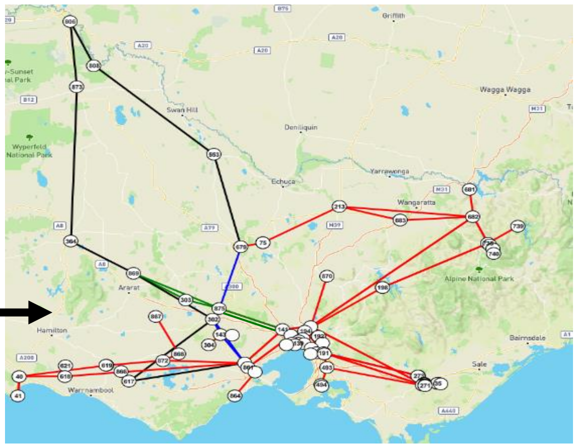

Figure 4: Our representation of the Victorian part of the NEM with the new transmission lines in green and the minor augmentations in black.

2.3. Gas supply adequacy outlook and network expansion

The gas network model in this work is updated to reflect two key findings identified in AEMO's Victorian Gas Planning Reports [7] and [8]. These are:

- Committed gas supply in Victoria is forecast to decline by 37% in 2024 due to the depletion of a key Gippsland gas field and several other smaller gas fields. This will result in a forecast Victorian supply shortfall for a 1-in-2-year peak gas system demand day (winter 2024) and an even greater forecast shortfall on a 1-in-20-year peak gas system demand day (winter 2024). This is illustrated in Figure 5, which shows actual and forecast peak day supply capacity (including pipeline constraints) by location, and peak day demand, from 2013 to 2024.
- The South West Pipeline (SWP) is expanded to increase the Iona underground storage (UGS) refilling capacity and enable anticipated supply projects located in the Otway Basin, which would otherwise be constrained by the capacity of the SWP, to improve annual supply balance and possibly alleviate forecast peak day supply issues. As such, the Western Outer Ring Main (WORM) [9] will connect the SWP/Brooklyn to Lara Pipeline (BLP) to the Victorian Northern Interconnect (VNI) and Longford to Melbourne Pipeline (LMP). The WORM is highlighted in red in Figure 6, which depicts our representation of the Victorian Declared Transmission System (DTS).

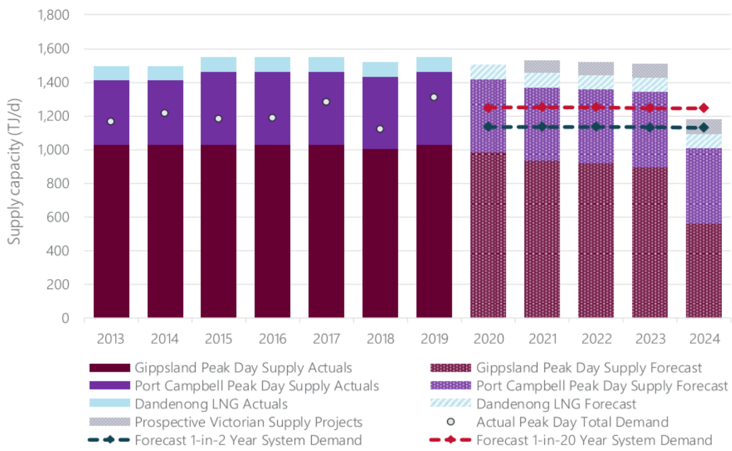

Figure 5: Actual and forecast peak day gas supply capacity (including pipeline constraints) by location, and peak day gas demand, from 2013 to 2024 [8].

Figure 6: Our representation of the Victorian DTS with the WORM highlighted in red.

A summary of the forecast DTS supply adequacy for 2019 and 2024, including anticipated supply projects and pipeline constraints, is shown in Table 1.[5]

Table 1: Forecast DTS supply adequacy for 2019 and 2024 (including anticipated supply projects and pipeline constraints).

Supply zone	2019	2024
Gippsland[1]	1030 TJ/d	651 TJ/d
Port Campbell[2]	434 TJ/d	449 TJ/d
Dandenong LNG	87 TJ/d	87 TJ/d
Total available	1550 (TJ/d) = 64.625 (TJ/h)	1187 (TJ/d) = 49.46 (TJ/h)

[1] The supply in the Gippsland zone is the aggregated gas supply from Longford CPP and Pakenham.
[2] The supply in the Port Campbell zone is the aggregated gas supply from Iona UGS, Otway, and Minerva.

Before analysing the impact of this reduction in gas supply on the 2024 gas network, the model is backtested against historical hourly linepack[6] data from AEMO for the 1-in-20-year peak system demand of August 09 2019, which is illustrated in Figure 7. Figure 7 shows that the simulated linepack closely matches the actual one from AEMO.[7] Figure 7 also shows that the gas supply in 2019 was adequate enough to bring the end-of-day (EoD) linepack close to its value at the beginning-of-day (BoD).[8] This is a desirable outcome as market operators such as AEMO set a BoD linepack target that maintains efficient and safe system operational conditions [10]. The BoD linepack target for the DTS is around 850TJ in winter and includes both passive and active linepack [7]. The value of the linepack target is set to account for the impact of unscheduled GPG demand [11] and surprise cold weather[9] [7]. The model was also backtested against historical linepack data for a medium-demand day (August 21, 2019) and a low-demand day (November 23, 2019), but the results are not shown here in the interest of space. Those results can be found in the previous milestone report as part of this project.

The gas flow model can now be used to analyse the gas supply adequacy in 2024, starting with a forecast consisting of a 1-in-20-year peak gas system demand of 1308 TJ/d followed by an average winter gas demand day of 1160 TJ/d (the average demand over the two days is 1228.2 TJ/d). The hourly linepack profile along with the demand and supply profiles for this forecast are shown in Figure 8. In this forecast, the gas supply shortfall is 1228.2 – 1187 = 41 TJ/d, which translates to an EoD linepack on the second day that is 103 TJ below the BoD linepack of the first day. This is not desirable as the BoD linepack of the next gas day (the third gas day in this case) would now be 103TJ below the desired BoD target of around 850TJ.

[5] The anticipated supply includes the uncommitted projects that have reasonable expectations to achieve all necessary approvals.
[6] The "linepack" is the amount of pressurized gas stored in a pipeline. The change in linepack throughout the gas day is equal to the cumulative difference between injections and withdrawals [10].
[7] The gas flow model is based on a dynamic (transient) model of the gas system (See Appendix A).
[8] The EoD linepack is measured at the end of a gas day at 6 AM and is equal to the BoD linepack for the next gas day.
[9] The linepack is depleted quicker than expected if scheduled BoD injections are lower than required to meet the actual demand (i.e., when actual demand exceeds forecast demand).

The second forecast, shown in Figure 9, is more extreme and consists of two consecutive 1-in-20-year peak gas system demand days of 1308 TJ/d in 2024. In this forecast, the gas supply shortfall is 1308 – 1187 = 121 TJ/d, which translates to an EoD linepack that is 243 TJ below the BoD linepack. Furthermore, between 7:30PM and 12:30AM on the second day the linepack drops below a value that violates minimum pressure limits, which may compromise the security of the gas system and might call for gas demand disconnection to prevent undesirably low pressures on the gas network, with risk of equipment maloperation and even system shutdown.

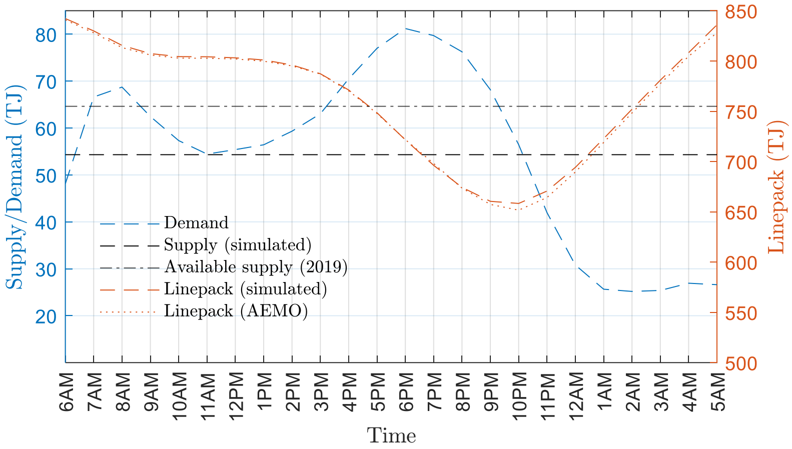

Figure 7: Historical and simulated linepack of the 1-in-20-year peak gas system demand of August 09, 2019 (1308 TJ/d).

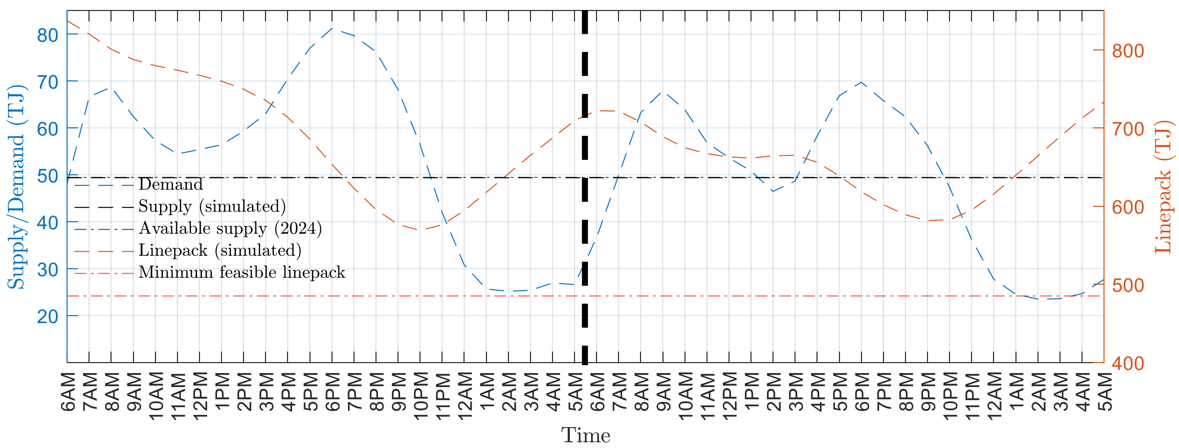

Figure 8: Gas supply and linepack profiles for a forecast of a 1-in-20-year peak gas system demand day (1308 TJ/d) followed by an average winter demand day (1160 TJ/d) in 2024.

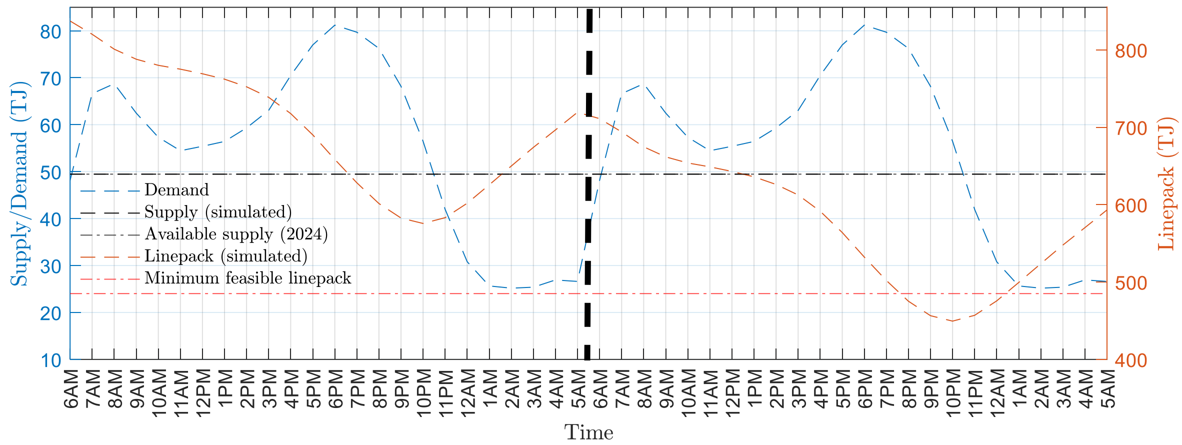

Figure 9: Gas supply and linepack profiles for a forecast of two consecutive 1-in-20-year peak gas system demand days (1308 TJ/d) in 2024.

2.4. Methodology

This section describes the algorithmic methodology underlying the studies in this report. A flow chart detailing this methodology is shown in Figure 10. The input data consists mainly of the electricity and gas network infrastructures, electricity and gas demand profiles, RES forecasts, generation information, and supply information. The first stage implements a unit commitment with a "strengthened" direct-current optimal power flow (DC-OPF)[10] model solved over a 24-hour scheduling horizon with a half-hourly resolution. Demand forecasts and RES availability forecasts are acquired from AEMO [2]. Unit commitment constraints on coal-fired generators include, minimum stable generation (MW), minimum up-time and down-time (hours)[11], ramp rates (MW/minute), and reserve requirements (MW)[12]. These are all taken from AEMO's Input and Assumptions Workbook 2019 [5]. The first stage determines the optimal dispatch of the generation mix and the amount, time, and location of RES curtailments. The second stage consists of a transient gas flow model (see Appendix A for more detail).

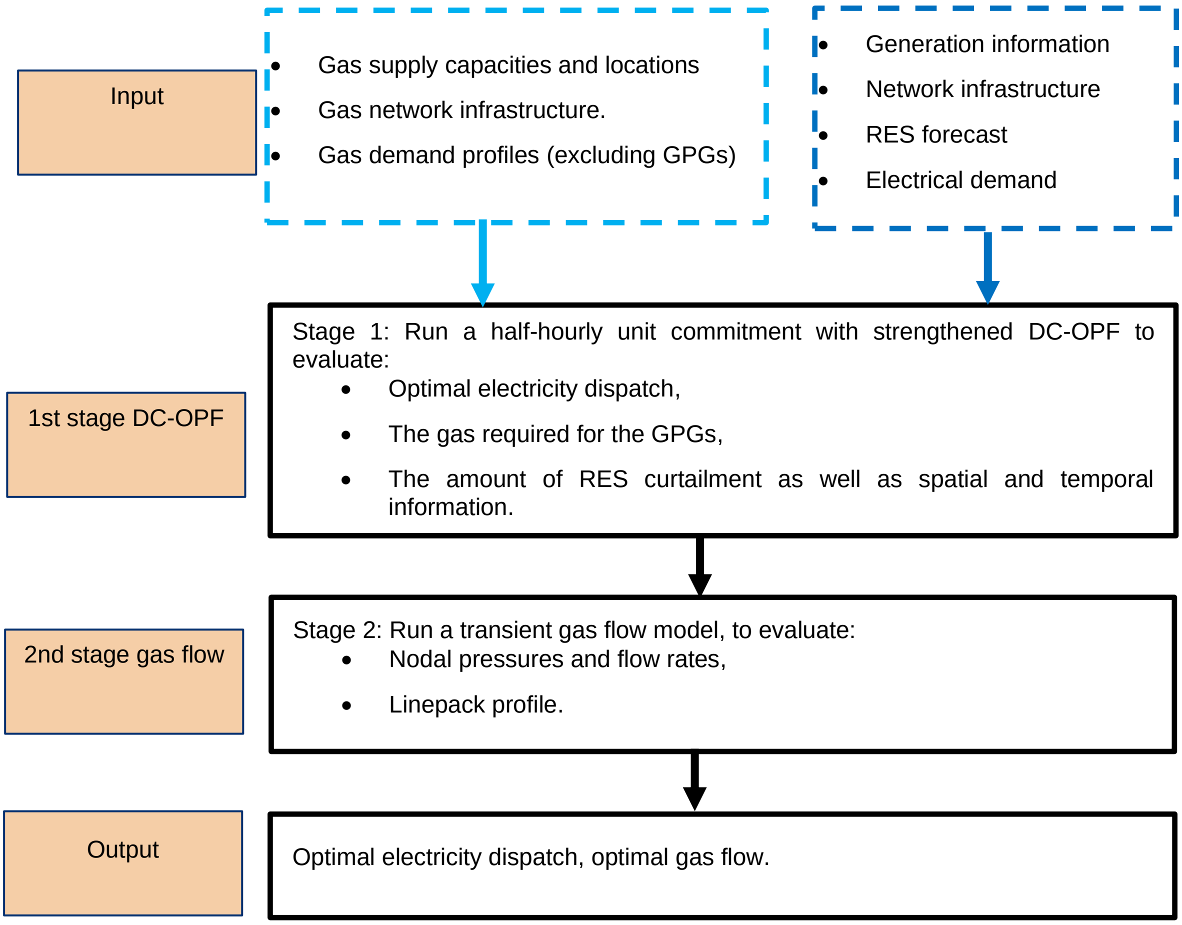

Figure 10: The algorithmic methodology.

[10] The strengthened DC-OPF minimises the overall operational cost while satisfying the electricity demand subject to electricity transmission system constraints including network *losses*, which are usually overlooked in most studies (that is why we talk about "strengthened" DC-OPF). In particular, as losses grow with the square of the electric current (and thus in first approximation of the power), they become much more significant at peak times, which is particularly important in the case, e.g., of heating electrification when heating peak demand overlaps the electricity peak demand in winter.

[11] The minimum up-time of the coal-fired generators in Victoria is 16 hours, as specified in AEMO's Input and Assumptions Workbook 2019 [5].

[12] For the sake of simplicity, even in future scenarios reserve requirements for Victoria are assumed to be equal to 498 MW, as per the specifications in AEMO's Input and Assumptions Workbook 2019 [5]. In practice, it is likely that these requirements may change with RES level and type.

3. ELECTRIFICATION OF RESIDENTIAL HEATING

Electrification studies in this section are conducted for five different cases in 2025. These are:

- 1-in-20-year peak gas system demand day,
- Low-wind, 1-in-20-year peak gas system demand day,
- Average winter gas demand day,
- Low-wind, average winter gas demand day, and
- Average autumn gas demand day.

Each one of the five different electrification scenarios consists of three subcases where gas space heating (SH) and gas domestic hot water (DHW) are replaced with electric options:

- 0% SH and 0% DHW,
- 50% SH and 50% DHW, and
- 100% SH and 100% DHW,

for a total of fifteen scenarios. The underlying model is described in Section 2.4.

Residential gas demand profiles are based on the analysis in [12] and the assumptions in [13] and [14]. In more detail, SH and DHW demands are assumed to account for 75% and 23% of the residential gas consumption, respectively, whereas cooking demand accounts for 2% of the residential gas consumption and is assumed to be uniform between 5pm and 11pm [13],[14]. The normalised residential gas demand profile for a typical winter weekday is depicted in Figure 11.

The proportion of gas consumption in different sectors, excluding the gas consumed by GPGs, is shown in Table 2 [14],[15].

Table 2: Gas consumption by sector in Victoria.

Region	Residential	Commercial	Industrial
VIC	49%	16%	35%

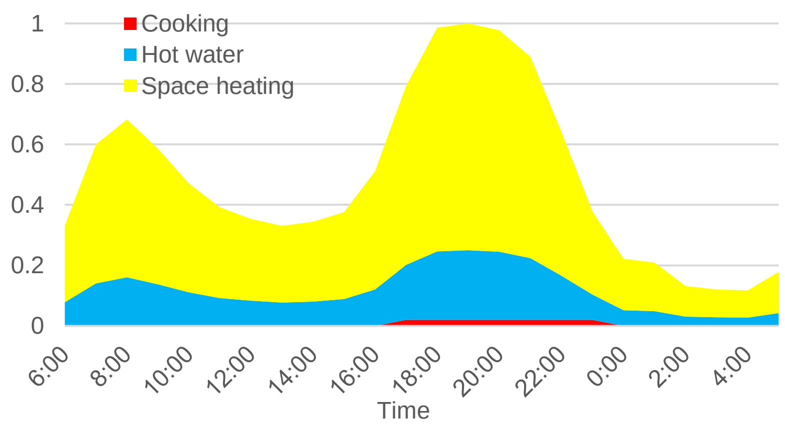

Figure 11: Normalised residential gas demand profile for a typical winter weekday.

Existing gas boilers and electric hot water heaters are assumed to have average thermal efficiencies of 85% and 95%, respectively [16],[17]. In all the electrification scenarios below, *air-to-water* electric heat pumps (EHPs) have been used here for both SH and DHW with a CoP shown in Figure 12 for different water temperatures ranging from 30°C to 55°C.[13] The CoP of the *air-to-water* EHPs varies with respect to the outside temperature and the heating

[13] It should be noted that air-to-water EHPs have been used here for both space heating and domestic hot water. However, this is for illustration purposes only, in order to illustrate the potential nature of the network and system impact of electrification and the type of analysis that the modelling tool could facilitate. Specific, more realistic heat electrification studies would require industry agreement on scenario assumptions for technology type and characteristics. Such new studies would be relatively straightforward to run.

system water temperature. The water temperature of the *air-to-water* EHPs is assumed to be 50°C in all the electrification scenarios below.

Electric SH demand is assumed to be provided solely by *air-to-water* electric heat pumps (EHPs) with the CoP shown in Figure 12 for a water temperature of 50°C.

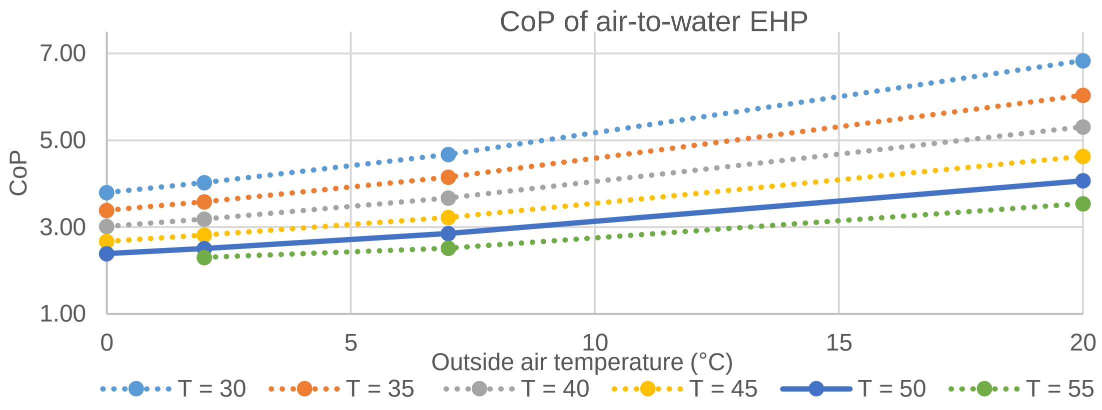

Figure 12: CoP of the considered air-to-water EHP for different water temperatures ranging from 30°C to 55°C.

On the other hand, electric DHW demand is assumed to be provided by air-to-water EHPs *coupled* with electric hot water heaters with an efficiency of 95%, for an overall coefficient of performance (CoP) shown in Figure 13. The hot water heaters are used to raise the water temperature from 50°C to 60°C to prevent the growth of some strains of bacteria (such as *Legionella*) [18].

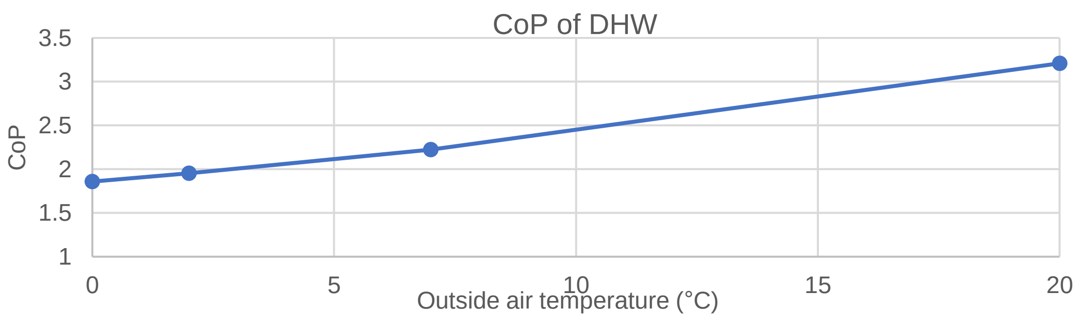

Figure 13: Overall CoP of DHW (air-to-water EHP + electric hot water heater).

Outside temperature profiles for each demand zone are obtained from the Bureau of Meteorology [19] in a half-hourly resolution. Zonal gas demands are obtained from AEMO [20], under " Public D+3 Metering Data ". Note that these zonal demands include the gas consumed by GPGs, which were then subtracted with the help of the metered power (MW) outputs obtained from AEMO's SCADA values [21] of the corresponding GPGs. Heat rates (GJ/MWh) of the corresponding GPGs are obtained from AEMO's Input and Assumptions Workbook 2019 [5]. Finally, Section 3.6 assesses the CO_2 emissions for the fifteen electrification scenarios in Section 3.1 to 3.5 below.

3.1. 1-in-20-year peak gas system demand day (August 09, 2025)

In this scenario, the 1-in-20-year peak gas system demand day of August 09, 2019 is projected onto the same day in 2025, i.e., August 09, 2025. The purpose of this scenario is to assess the impact of the electrification of residential heating on both the supply adequacy of both the electricity and gas systems for a 1-in-20-year peak gas system demand day under the generation mix, electricity demand forecast, and RES output forecasts of August 09, 2025 in the Central scenario of the ISP.

3.1.1. 0% SH and 0% DHW (base case)

This base-case scenario is characterised by an average of 1777 MW of wind power and a net gas demand (excluding gas consumed by GPGs) of 1188 TJ/d. The electricity generation profile is shown in Figure 14. Since there are no imports from other states, it can be concluded that the generation is adequate to supply the demand. On the gas network side, the total gas demand (including gas consumed by GPGs) is 1229 TJ/d. The hourly linepack profile, along with the demand and supply profiles for this scenario, are shown in Figure 15, which also shows that the gas supply shortfall is 1229 – 1187 = 42 TJ/d. This translates to an EoD linepack that is 46 TJ below the BoD linepack target (see Section 2.3), confirming the “stretch” of the gas network in dealing with extreme conditions.

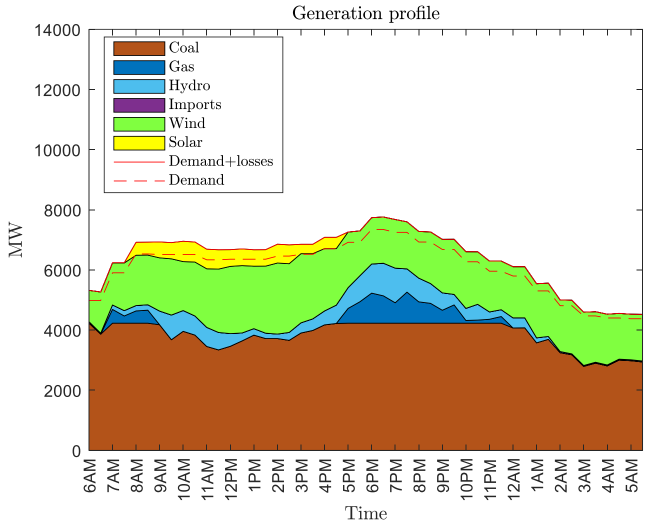

Figure 14: Generation profile under 0% SH and 0% DHW electrification (base case) for the 1-in-20-year peak gas system demand day projected onto August 09, 2025.

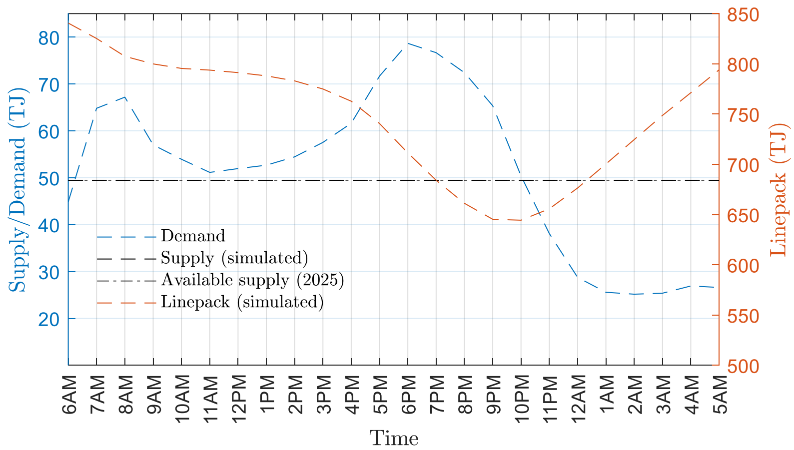

Figure 15: Linepack and gas supply profiles under 0% SH and 0% DHW electrification (base case) for the 1-in-20-year peak gas system demand day projected onto August 09, 2025.

3.1.2. 50% SH and 50% DHW

This “50% SH and 50% DHW” scenario is characterised by an average of 1781 MW of wind power and a net gas demand (excluding gas consumed by GPGs) of 902 TJ/d. Compared to the base case, 286 TJ/d of energy from residential heating is shifted from the gas system to the electricity system. As a result, the electricity generation profile in Figure 16 shows that the shortfall in generation between 4:30PM to 10PM needs to be supplemented by imports from other states through the interconnectors. However, those imports are within the interconnector capacities and therefore no augmentation is needed. On the gas network side, the total gas demand (including gas consumed by GPGs) is 1117 TJ/d. The hourly linepack profile, along with the demand and supply profiles for this scenario, are shown in Figure 17, which also shows that the gas supply is adequate, as evidenced by an EoD linepack that is close to the BoD linepack target (see Section 2.3). Compared to the base case, the GPG demand increased by 174 TJ/d (from 41 TJ/d to 215 TJ/d) but this increase in GPG demand is offset by a larger decrease in residential heating demand for a total gas demand decrease of 112 TJ/d compared to the base case.

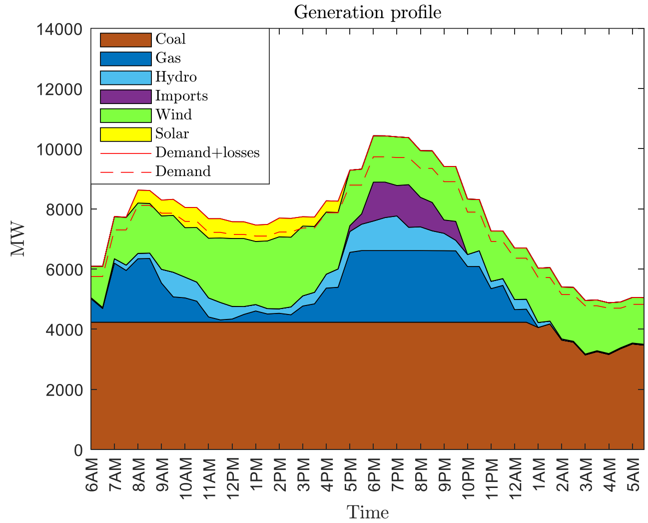

Figure 16: Generation profile under 50% SH and 50% DHW electrification (base case) for the 1-in-20-year peak gas system demand day projected onto August 09, 2025.

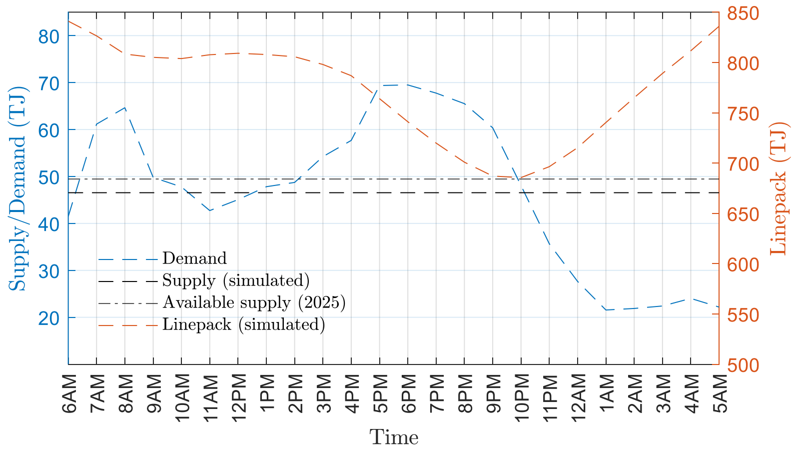

Figure 17: Linepack and gas supply profiles under 50% SH and 50% DHW electrification for the 1-in-20-year gas system demand day projected onto August 09, 2025.

3.1.3. 100% SH and 100% DHW

This "100% SH and 100% DHW" scenario is characterised by an average of 1806 MW of wind power and a net gas demand (excluding gas consumed by GPGs) of 615 TJ/d. Compared to the base case, 573 TJ/d of energy from residential heating is shifted from the gas system to the electricity system. As a result, the electricity generation profile in Figure 18 shows that the shortfall in generation between 6:30AM and 9:30AM and between 4PM to 11PM needs to be supplemented by imports from other states through the interconnectors. In this instance, these imports exceed interconnector capacities by an average of 1500 MW, which entails that interconnector augmentation might be needed in principle. Furthermore, this unusually high demand (for Victoria), which peaks at 12GW, requires network augmentation in the form of an 11% increase in MVA (thermal) capacity on some internal transmission lines. On the gas network side, the total gas demand (including gas consumed by GPGs) is 938 TJ/d. The hourly linepack profile, along with the demand and supply profiles for this scenario, are shown in Figure 19, which also shows that the gas supply is adequate, as evidenced by an EoD linepack that is close to the BoD linepack target (see Section 2.3). Compared to the base case, the GPG demand increased by 282 TJ/d (from 41 TJ/d to 323 TJ/d), but this increase in GPG demand is offset by a larger decrease in residential heating demand for a total gas demand decrease of 291 TJ/d compared to the base case.

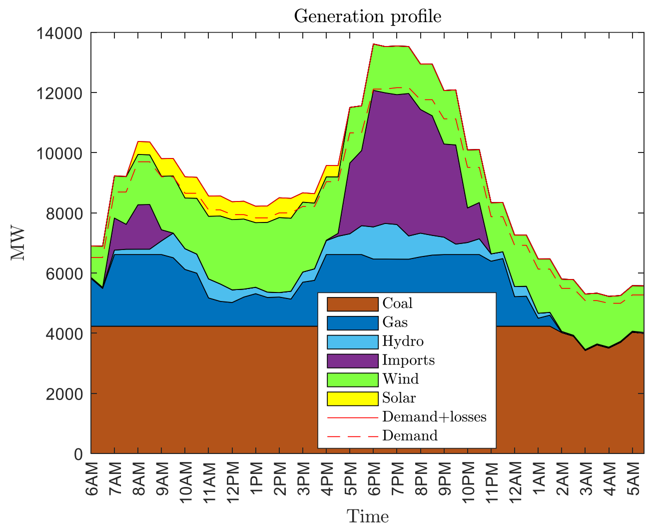

Figure 18: Generation profile under 100% SH and 100% DHW electrification for the 1-in-20-year peak gas system demand projected onto August 09, 2025.

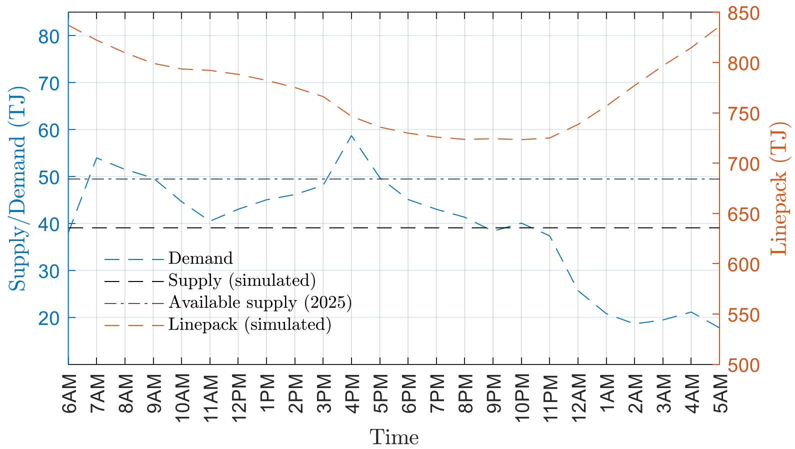

Figure 19: Linepack and gas supply profiles under 100% SH and 100% DHW electrification for the 1-in-20-year peak gas system demand projected onto August 09, 2025.

3.2. Low-wind 1-in-20-year peak gas system demand day (August 9, 2025)

This scenario is the same as the one in Section 3.1 but with only 10% of the wind forecast. The forecast power from solar farms is kept the same as the one in Section 3.1. Note that the output power from Solar farms is zero in the evening during which the winter peak demand occurs. The purpose of this scenario is to assess the impact of the electrification of residential heating on a low-wind day on both the electricity and gas systems for a 1-in-20-year peak gas system demand day under the generation mix, electricity demand forecast, and RES availability forecasts of August 09, 2025 in the Central scenario of the ISP.

3.2.1. 0% SH and 0% DHW (base case)

This base-case scenario is characterised by an average of 184 MW of wind power and a net gas demand (excluding gas consumed by GPGs) of 1188 TJ/d. The electricity generation profile in Figure 20 shows more dispatch of power from GPGs and gas-fired generators to compensate for the unavailability of wind power. In fact, Figure 20 shows that despite all the coal-fired generators now operating at full capacity across the whole day, there is still a shortfall in generation between 5:30PM to 8PM that needs to be supplemented by imports from other states through the interconnectors. However, these imports are within the interconnector capacities and no augmentation is needed. On the gas network side, the total gas demand (including gas consumed by GPGs) is 1452 TJ/d. The hourly linepack profile, along with the demand and supply profiles for this scenario, are shown in Figure 21, which also shows that the gas supply shortfall is 1452 – 1187 = 265 TJ/d. This translates to an EoD linepack that is 265 TJ below the BoD linepack target (see Section 2.3). As a result, the linepack swing is more pronounced and, between 8:30AM and 12:30AM, the linepack drops below a value that could violate minimum pressure limits, which might compromise the security of the gas system. The increase in total gas demand compared to the base case in Section 3.1 is due to the dispatch of more power from peaking GPGs to balance system demand and supply in the absence of wind power, as seen in Figure 20. More specifically, the unavailability of wind power in this case leads to an increase in gas consumption of 1452 – 1229 = 223 TJ from GPGs compared to the base case in Section 3.1.

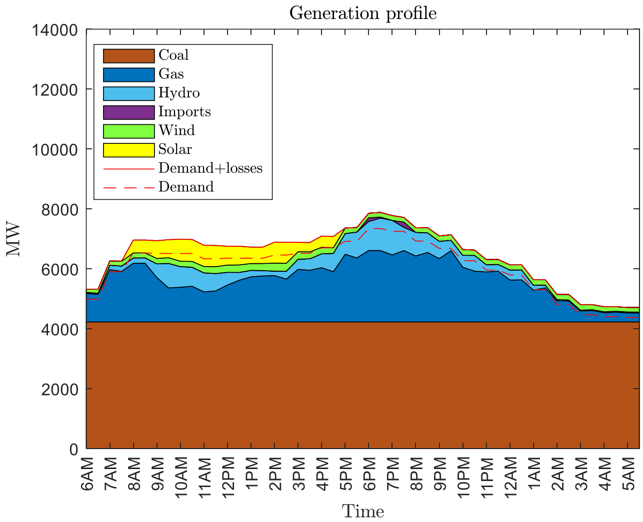

Figure 20: Generation profile under 0% SH and 0% DHW electrification (base case) for the low-wind 1-in-20-year peak gas system demand projected onto August 09, 2025.

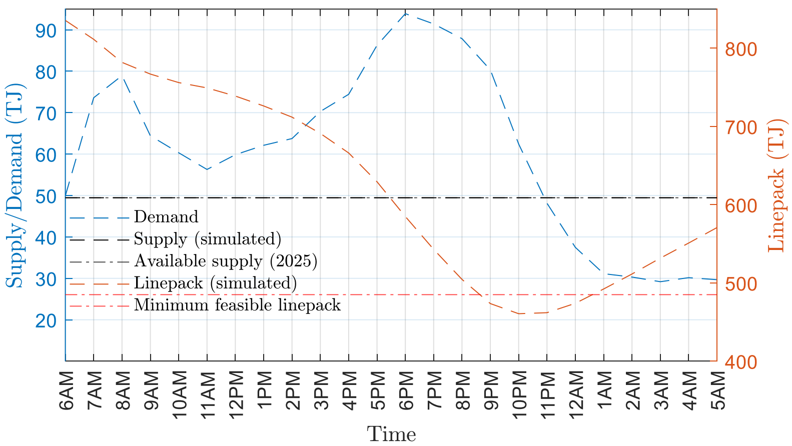

Figure 21: Linepack and gas supply profiles under 0% SH and 0% DHW electrification (base case) for the low-wind 1-in-20-year peak gas system demand projected onto August 09, 2025.

3.2.2. 50% SH and 50% DHW

This “50% SH and 50% DHW” scenario is characterised by an average of 184 MW of wind power and a net gas demand (excluding gas consumed by GPGs) of 902 TJ/d. Compared to the base case, 286 TJ/d of energy from residential heating is shifted from the gas system to the electricity system. As a result, the electricity generation profile in Figure 22 shows that the shortfall in generation between 6:30AM and 10AM and between 2:30PM to 12AM needs to be supplemented by imports from other states through the interconnectors. However, these imports exceed interconnector capacities by an average of 900 MW, which entails that an interconnector augmentation might be needed in principle. On the gas network side, the total gas demand (including gas consumed by GPGs) is 1332 TJ/d. The hourly linepack profile, along with the demand and supply profiles for this scenario, are shown in Figure 23, which also shows that the gas supply shortfall is 1332 – 1187 = 145 TJ/d. This translates to an EoD linepack that is 145 TJ below the BoD linepack target (see Section 2.3). Compared to the low-wind base case, the

GPG demand increased by 166 TJ/d (from 264 TJ/d to 430 TJ/d) but this increase in GPG demand is offset by a larger decrease in residential heating demand for a total gas demand decrease of 120 TJ/d compared to the low-wind base case. Similar to the previous case, the increase in total gas demand compared to the "50% SH and 50% DHW" scenario in Section 3.1 is due to the dispatch of more power from peaking GPGs to balance system demand and supply in the absence of wind power, as seen in Figure 22. More specifically, the unavailability of wind power in this case leads to an increase in gas consumption of 1332 – 1117 = 215 TJ from GPGs demand compared to the "50% SH and 50% DHW" scenario in Section 3.1.

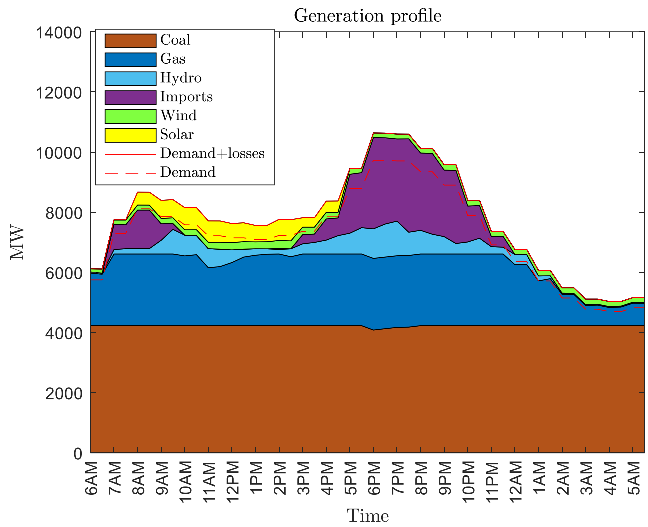

Figure 22: Generation profile under 50% SH and 50% DHW electrification for the low-wind 1-in-20-year peak gas system demand projected onto August 09, 2025.

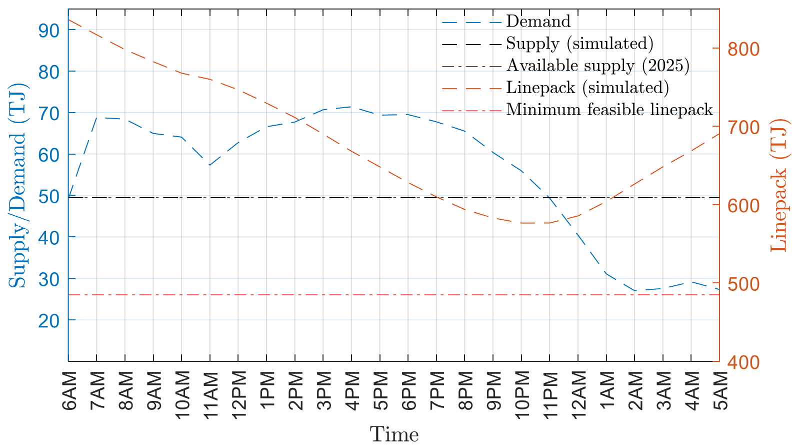

Figure 23: Linepack and gas supply profiles under 50% SH and 50% DHW electrification for the low-wind 1-in-20-year peak gas system demand projected onto August 09, 2025.

3.2.3. 100% SH and 100% DHW

This "100% SH and 100% DHW" scenario is characterised by an average of 184 MW of wind power and a net gas demand (excluding gas consumed by GPGs) of 615 TJ/d. Compared to the base case, 573 TJ/d of energy from residential heating is shifted from the gas system to the electricity system. As a result, the electricity generation profile in Figure 24 shows that the shortfall in generation between 6:30AM and 9:30AM and between 4PM to 11PM needs to be supplemented by imports from other states through the interconnectors. However, these imports exceed interconnector capacities by an average of 3500 MW, which entails that an interconnector augmentation might be in principle be needed[14]. Furthermore, this unusually high demand (for Victoria), which peaks at 12 GW, requires network augmentation in the form of up to 220% increase in MVA (thermal) capacity on some internal transmission lines. On the gas network side, the total gas demand (including gas consumed by GPGs) is 1084 TJ/d. The hourly linepack profile, along with the demand and supply profiles for this scenario are shown in Figure 25, which also shows that the gas supply is adequate, as evidenced by an EoD linepack that is close to the BoD linepack target (see Section 2.3). Compared to the low-wind base case, the GPG demand increased by 205 TJ/d (from 264 TJ/d to 469 TJ/d), but this increase in GPG demand is offset by a larger decrease in residential heating demand for a total gas demand decrease of 368 TJ/d compared to the low-wind base case. Similar to the previous two cases, the increase in total gas demand compared to the "100% SH and 100% DHW" scenario in Section 3.1 is due to the dispatch of more power from peaking GPGs to balance system demand and supply in the absence of wind power, as seen in Figure 24. More specifically, the unavailability of wind power in this case leads to an increase in gas consumption of 1084 – 938 = 146 TJ from GPGs compared to the "100% SH and 100% DHW" scenario in Section 3.1.

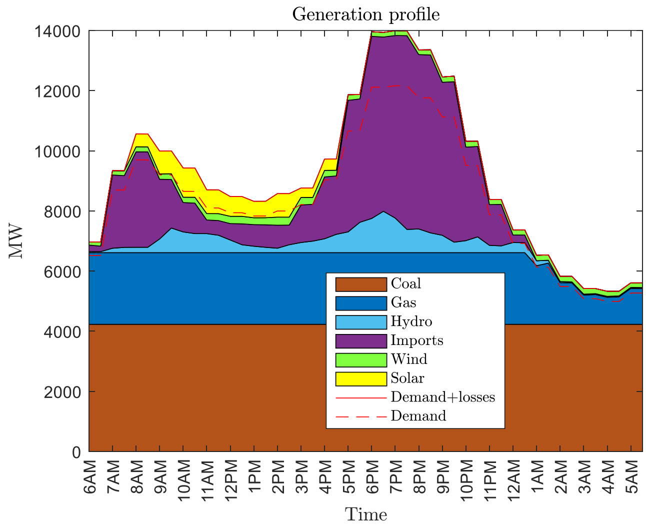

Figure 24: Generation profile under 100% SH and 100% DHW electrification for the low-wind 1-in-20-year peak gas system demand projected onto August 09, 2025.

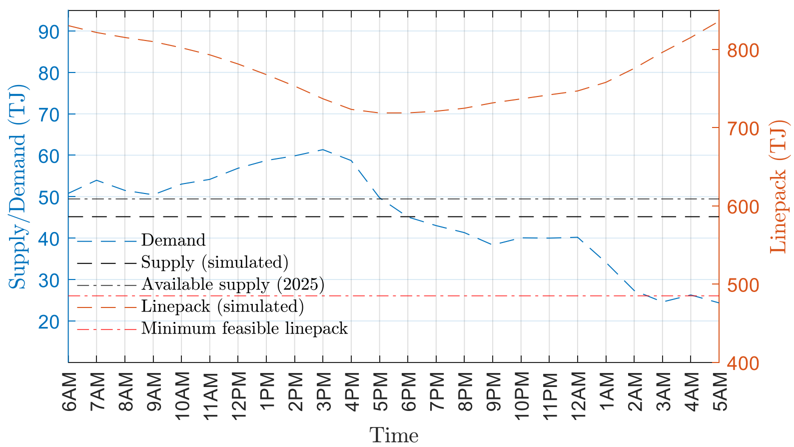

Figure 25: Linepack and gas supply profiles under 100% SH and 100% DHW electrification for the low-wind 1-in-20-year peak gas system demand projected onto August 09, 2025.

[14] There might be other options to avoid interconnector augmentation, including storage. On the other hand, it should be clear that the analysis provided here is only indicative of the reliability performance of the system under stress and the required augmentation. It is very likely that a systematic and rigorous reliability assessment, to be carried out via reliability engineering probabilistic techniques, would suggest that even greater reinforcements than estimated here might be needed.

3.3. Average winter demand day (July 03, 2025)

In this scenario, an average winter gas demand day of July 03, 2020 is projected onto the same day in 2025, i.e., July 03, 2025. The purpose of this scenario is to assess the impact of the electrification of residential heating on the supply adequacy of both the electricity and gas systems for an average winter gas demand day under the generation mix, electricity demand forecast, and RES output forecasts of July 03, 2025 in the Central scenario of the ISP. This day is characterised by a large penetration of power from wind generators.[15]

3.3.1. 0% SH and 0% DHW (base case)

This base-case scenario is characterised by an average of 3212 MW of wind power and a net gas demand (excluding gas consumed by GPGs) of 1116 TJ/d. The electricity generation profile is shown in Figure 26. Since there are no imports from other states, it can be concluded that the generation is adequate to supply the demand. On the gas network side, the total gas demand is also 1116 TJ/d, as no gas in consumed by GPGs. The hourly linepack profile, along with the demand and supply profiles for this scenario, are shown in Figure 27, which also shows that the gas supply is adequate, as evidenced by an EoD linepack that is close to the BoD linepack target (see Section 2.3).

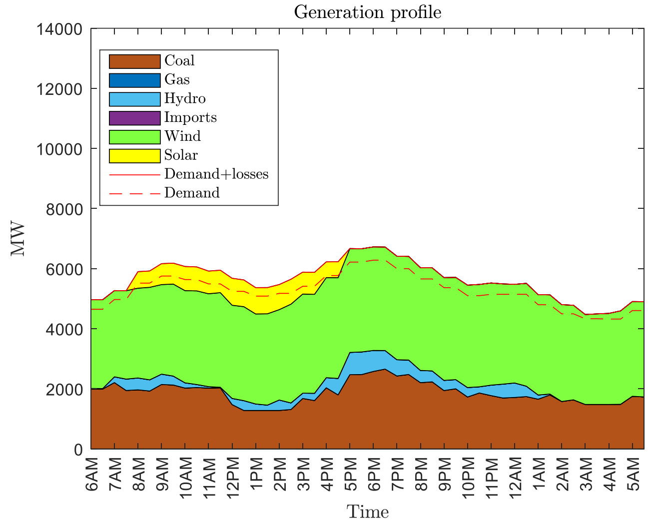

Figure 26: Generation profile under 0% SH and 0% DHW electrification (base case) for an average winter demand day in 2025.

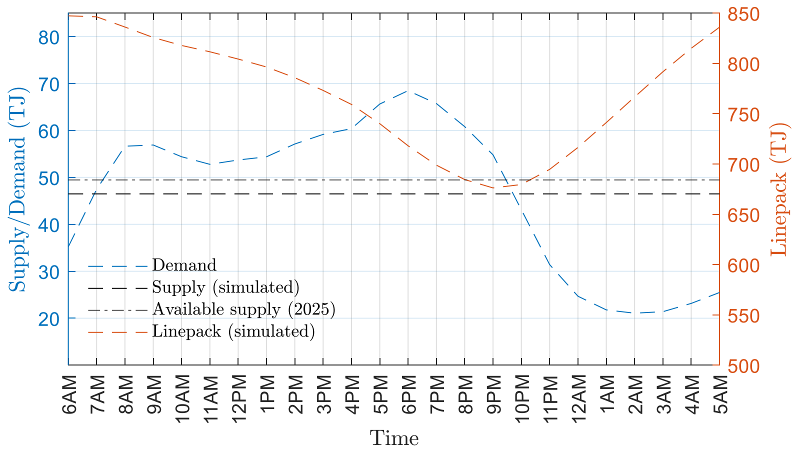

Figure 27: Linepack and gas supply profiles under 0% SH and 0% DHW electrification (base case) for an average winter demand day in 2025.

[15] The forecast of wind availability is obtained from [2].

3.3.2. 50% SH and 50% DHW

This "50% SH and 50% DHW" scenario is characterised by an average of 3115 MW of wind power and a net gas demand (excluding gas consumed by GPGs) of 851 TJ/d. Compared to the base case, 265 TJ/d of energy from residential heating is shifted from the gas system to the electricity system. The electricity generation profile is shown in Figure 28. Since there are no imports from other states, it can be concluded that the generation is adequate to supply the demand. On the gas network side, the total gas demand (including gas consumed by GPGs) is 870 TJ/d. The hourly linepack profile, along with the demand and supply profiles for this scenario, are shown in Figure 29, which also shows that the gas supply is adequate, as evidenced by an EoD linepack that is close to the BoD linepack target (see Section 2.3). Compared to the base case, the GPG demand increased by 19 TJ/d (from 0 TJ/d to 19 TJ/d) but this increase in GPG demand is offset by a larger decrease in residential heating demand for a total gas demand decrease of 246 TJ/d compared to the base case.

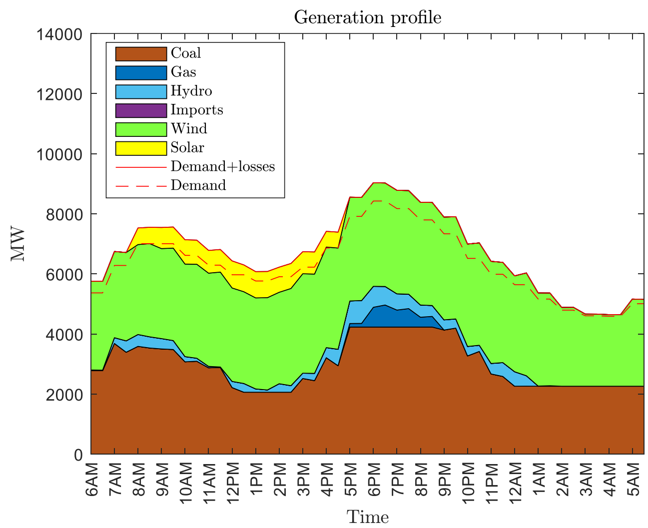

Figure 28: Generation profile under 50% SH and 50% DHW electrification for an average winter demand day in 2025.

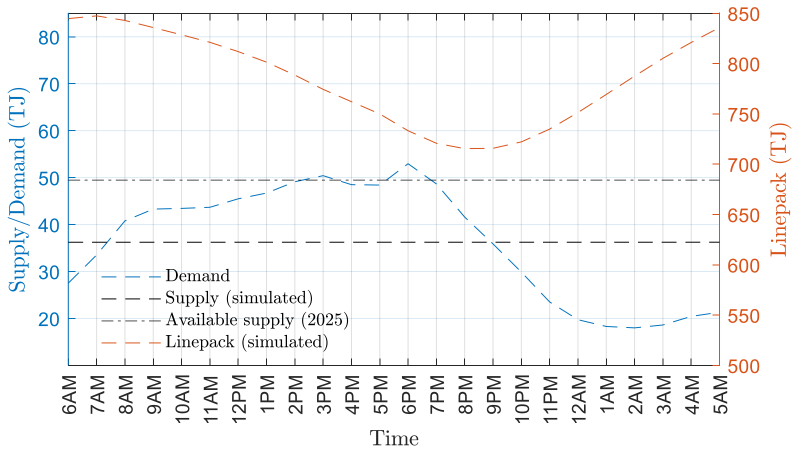

Figure 29: Linepack and gas supply profiles under 50% SH and 50% DHW electrification for an average winter demand day in 2025.

3.3.3. 100% SH and 100% DHW

This "100% SH and 100% DHW" scenario is characterised by an average of 3207 MW of wind power and a net gas demand (excluding gas consumed by GPGs) of 582 TJ/d. Compared to the base case, 533 TJ/d of energy from residential heating is shifted from the gas system to the electricity system. As a result, the electricity generation profile in Figure 30 shows that the shortfall in generation between 5:30PM to 9PM needs to be supplemented by imports from other states through the interconnectors. However, these imports are within the interconnector capacities and therefore no augmentation is needed. On the gas network side, the total gas demand (including gas consumed by GPGs) is 716 TJ/d. The hourly linepack profile, along with the demand and supply profiles for this scenario, are shown in Figure 31, which also shows that the gas supply is adequate, as evidenced by an EoD linepack that is close to the BoD linepack target (see Section 2.3). Compared to the base case, the GPG demand increased by 134 TJ/d (from 0 TJ/d to 134 TJ/d), but this increase in GPG demand is offset by a larger decrease in residential heating demand for a total gas demand decrease of 400 TJ/d compared to the base case.

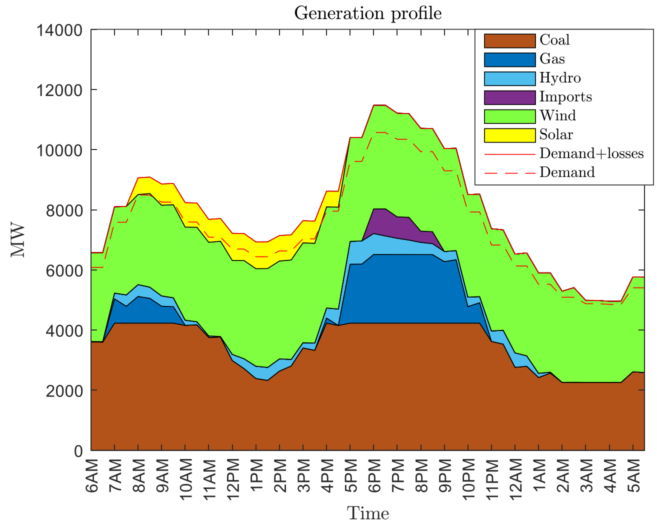

Figure 30: Generation profile under 100% SH and 100% DHW electrification for an average winter demand day in 2025.

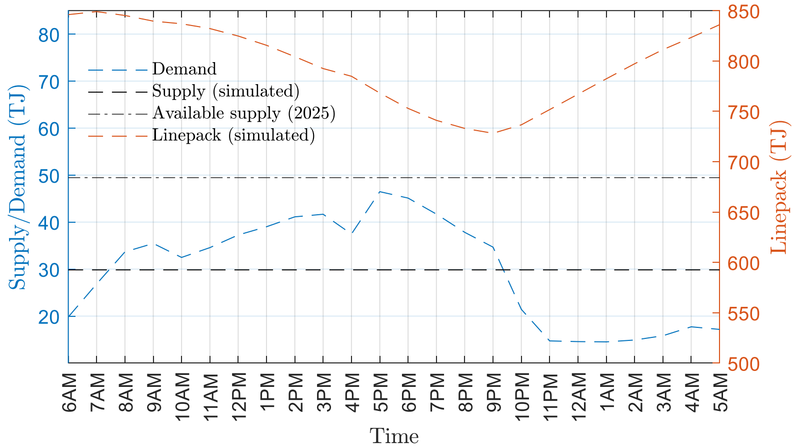

Figure 31: Linepack and gas supply profiles under 100% SH and 100% DHW electrification for an average winter demand day in 2025.

3.4. Low-wind average winter demand day (July 03, 2025)

This scenario is same as the one in Section 3.3, but with only 10% of the wind availability. The purpose of this scenario is to assess the impact of the electrification of residential heating on a low-wind day on both the electricity and gas systems for an average winter demand day under the generation mix, electricity demand forecast, and RES availability forecasts of July 03, 2025 in the Central scenario of the ISP.

3.4.1. 0% SH and 0% DHW (base case)

This base-case scenario is characterised by an average of 392 MW of wind power and a net gas demand (excluding gas consumed by GPGs) of 1116TJ/d. The electricity generation profile in Figure 32 shows an increase in power dispatch from GPGs and gas-fired generators to compensate for the unavailability of wind power. In fact, Figure 32 shows that all the coal-fired generators are now operating at almost full capacity across the whole day. However, since there are no imports from other states, it can be concluded that the generation is adequate to supply the demand. On the gas network side, the total gas demand (including gas consumed by GPGs) is 1206 TJ/d. The hourly linepack profile, along with the demand and supply profiles for this scenario, are shown in Figure 33, which also shows that the gas supply shortfall is 1206 – 1187 = 19 TJ/d. This translates to an EoD linepack that is 29 TJ below the BoD linepack target (see Section 2.3). The increase in total gas demand compared to the base case in Section 3.3 is due to the dispatch of more power from peaking GPGs to balance system demand and supply in the absence of wind power, as seen in Figure 32. More specifically, the unavailability of wind power in this case leads to an increase in gas consumption of 1206 – 1116 = 90 TJ from GPGs.

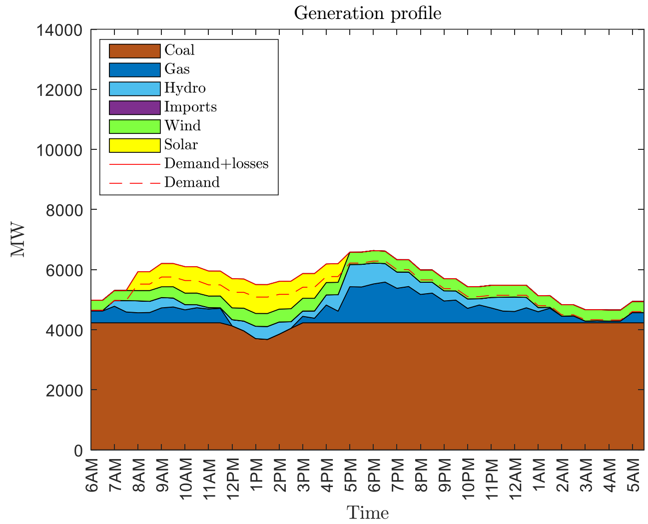

Figure 32: Generation profile under 0% SH and 0% DHW electrification (base case) for a low-wind average winter demand day in 2025.

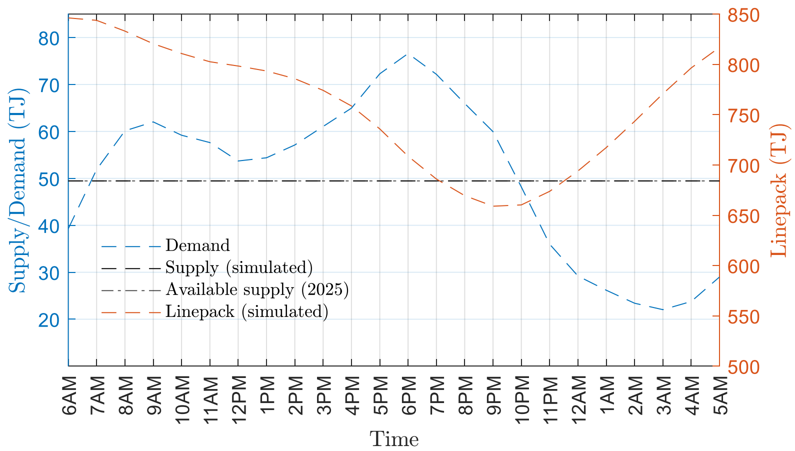

Figure 33: Linepack and gas supply profiles under 0% SH and 0% DHW electrification (base case) for a low-wind average winter demand day in 2025.

3.4.2. 50% SH and 50% DHW

This "50% SH and 50% DHW" scenario is characterised by an average of 392 MW of wind power and a net gas demand (excluding gas consumed by GPGs) of 851 TJ/d. Compared to the base case, 265 TJ/d of energy from residential heating is shifted from the gas system to the electricity system. As a result, the electricity generation profile in Figure 34 shows that the shortfall in generation between 4:30PM to 10PM needs to be supplemented by imports from other states through the interconnectors. However, these imports are within the interconnector capacities and therefore no augmentation is needed. On the gas network side, the total gas demand (including gas consumed by GPGs) is 1106 TJ/d. The hourly linepack profile, along with the demand and supply profiles for this scenario, are shown in Figure 35, which also shows that the gas supply is adequate, as evidenced by an EoD linepack that is close to the BoD linepack target (see Section 2.3). Compared to the low-wind base case, the GPG demand increased by 165 TJ/d (from 90 TJ/d to 255 TJ/d) but this increase in GPG demand is offset by a larger decrease in residential heating demand for a total gas demand decrease of 100 TJ/d compared to the low-wind base case. Similar to the previous case, the increase in total gas demand compared to the "50% SH and 50% DHW" scenario in Section 3.3 is due to the dispatch of more power from peaking GPGs to balance system demand and supply in the absence of wind power, as seen in Figure 34. More specifically, the unavailability of wind power in this case leads to an increase in gas consumption of 1106 – 870 = 236 TJ from GPGs compared to the "50% SH and 50% DHW" scenario in Section 3.3.

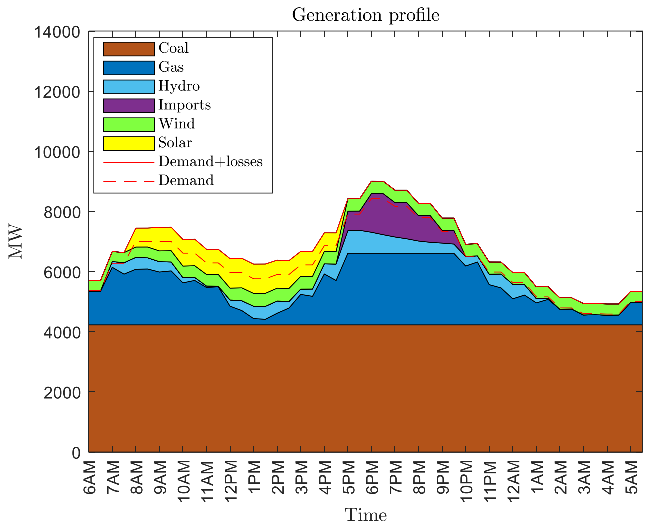

Figure 34: Generation profile under 50% SH and 50% DHW electrification for a low-wind average winter demand day in 2025.

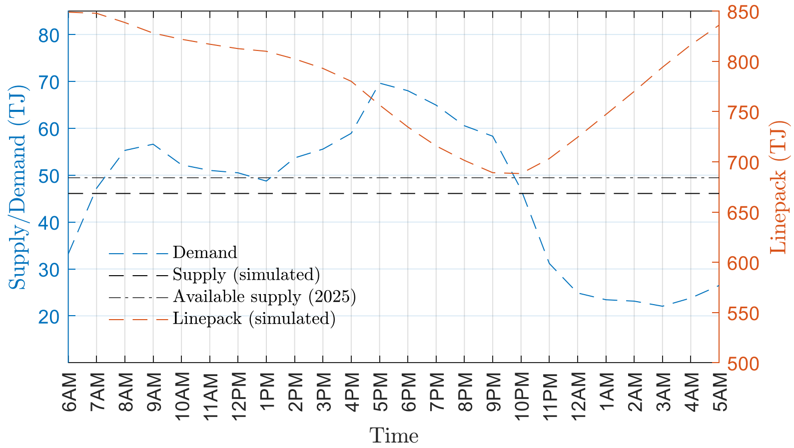

Figure 35: Linepack and gas supply profiles under 50% SH and 50% DHW electrification for a low-wind average winter demand day in 2025.

3.4.3. 100% SH and 100% DHW

This "100% SH and 100% DHW" scenario is characterised by an average of 392 MW of wind power and a net gas demand (excluding gas consumed by GPGs) of 582 TJ/d. Compared to the base case, 533 TJ/d of energy from residential heating is shifted from the gas system to the electricity system. As a result, the electricity generation profile in Figure 36 shows that the shortfall in generation between 6:30AM and 11AM and between 3:30PM to 11PM needs to be supplemented by imports from other states through the interconnectors. However, these imports exceed interconnector capacities by an average of 1400 MW, which entails that an interconnector augmentation might be needed in principle. On the gas network side, the total gas demand (including gas consumed by GPGs) is 952 TJ/d. The hourly linepack profile, along with the demand and supply profiles for this scenario are shown in

Figure 37, which also shows that the gas supply is adequate, as evidenced by an EoD linepack that is close to the BoD linepack target (see Section 2.3). Compared to the low-wind base case, the GPG demand increased by 280 TJ/d (from 90 TJ/d to 370 TJ/d), but this increase in GPG demand is offset by a larger decrease in residential heating demand for a total gas demand decrease of 254 TJ/d compared to the low-wind base case. Similar to the previous two cases, the increase in total gas demand compared to the “100% SH and 100% DHW” scenario in Section 3.3 is due to the dispatch of more power from peaking GPGs to balance system demand and supply in the absence of wind power, as seen in Figure 36. More specifically, the unavailability of wind power in this case leads to an increase in gas consumption of 952 – 716 = 236 TJ from GPGs compared to the “100% SH and 100% DHW” scenario in Section 3.3.

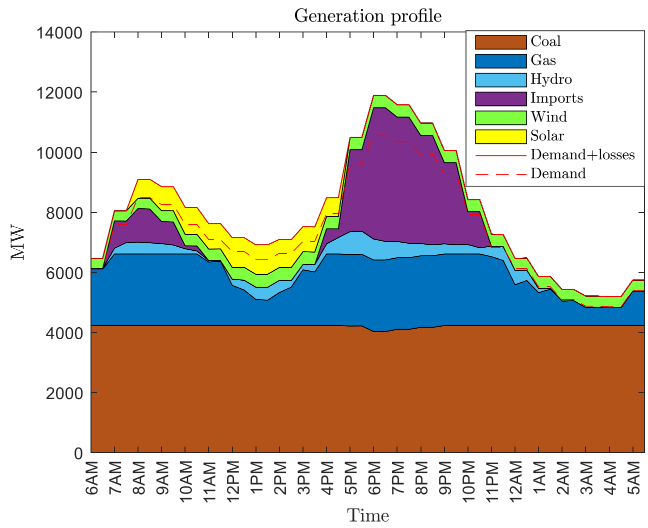

Figure 36: Generation profile under 100% SH and 100% DHW electrification for a low-wind average winter demand day in 2025.

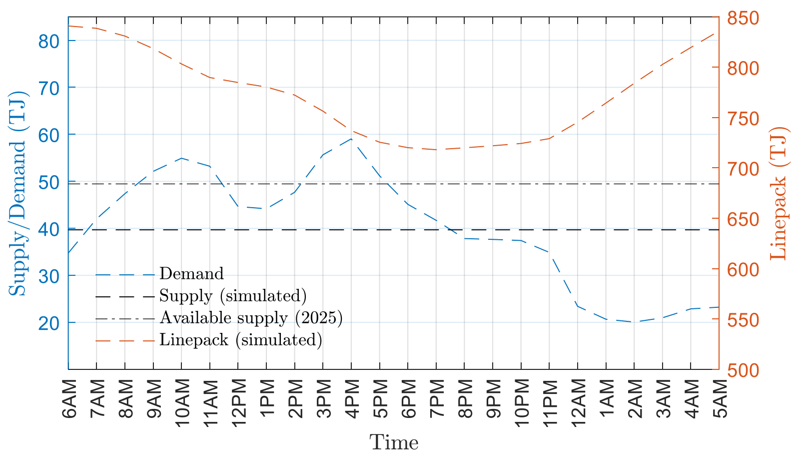

Figure 37: Linepack and gas supply profiles under 100% SH and 100% DHW electrification for a low-wind average winter demand day in 2025.

3.5. Average autumn demand day (May 21, 2025)

In this scenario, an average autumn gas demand day of May 21, 2020 is projected onto the same day in 2025, i.e., May 21, 2025. This scenario assesses both the supply adequacy of both the electricity and gas systems for an average winter gas demand day under the generation mix, electricity demand forecast, and RES availability forecasts of May 21, 2025 in the Central scenario of the ISP.

3.5.1. 0% SH and 0% DHW (base case)

This base-case scenario is characterised by an average of 842 MW of wind power and a net gas demand (excluding gas consumed by GPGs) of 907 TJ/d. The electricity generation profile is shown in Figure 38. Since there are no imports from other states, it can be concluded that the generation is adequate to supply the demand. On the gas network side, the total gas demand (including gas consumed by GPGs) is 944 TJ/d. The hourly linepack profile, along with the demand and supply profiles for this scenario, are shown in Figure 39, which also shows that the gas supply is adequate, as evidenced by an EoD linepack that is close to the BoD linepack target (see Section 2.3).

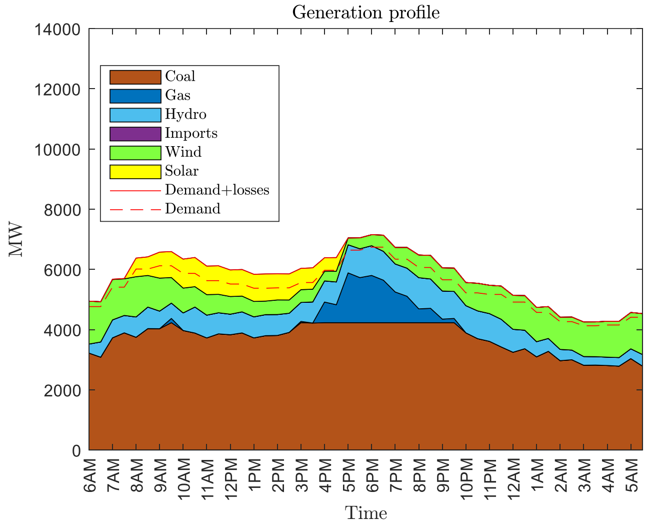

Figure 38: Generation profile under 0% SH and 0% DHW electrification (base case) for an average autumn demand day in 2025.

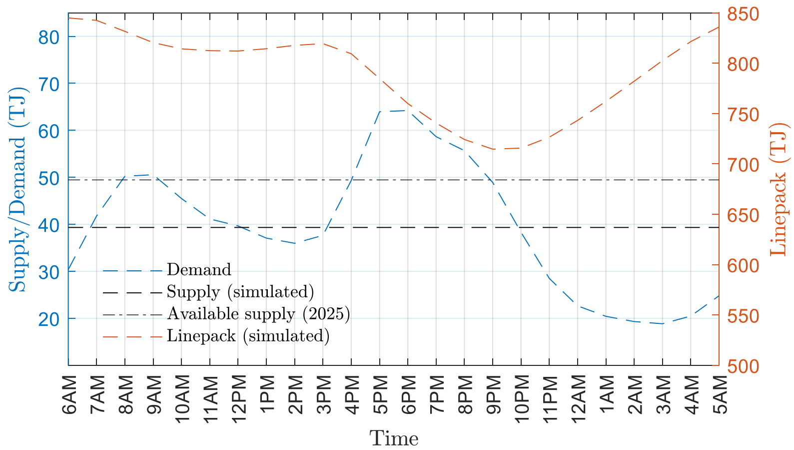

Figure 39: Linepack and gas supply profiles under 0% SH and 0% DHW electrification (base case) for an average autumn demand day in 2025.

3.5.2. 50% SH and 50% DHW

This “50% SH and 50% DHW” scenario is characterised by an average of 844 MW of wind power and a net gas demand (excluding gas consumed by GPGs) of 695 TJ/d. Compared to the base case, 212 TJ/d of energy from residential heating is shifted from the gas system to the electricity system. As a result, the electricity generation profile in Figure 40 shows that the shortfall in generation between 4:30PM to 8PM needs to be supplemented by imports from other states through the interconnectors. However, these imports are within the interconnector capacities and therefore no augmentation is needed. On the gas network side, the total gas demand (including gas consumed by GPGs) is 837 TJ/d. The hourly linepack profile, along with the demand and supply profiles for this scenario, are shown in Figure 41, which also shows that the gas supply is adequate, as evidenced by an EoD linepack that is close to the BoD linepack target (see Section 2.3). Compared to the base case, the GPG demand increased by 105 TJ/d (from 37 TJ/d to 142 TJ/d) but this increase in GPG demand is offset by a larger decrease in residential heating demand for a total gas demand decrease of 107 TJ/d compared to the base case.

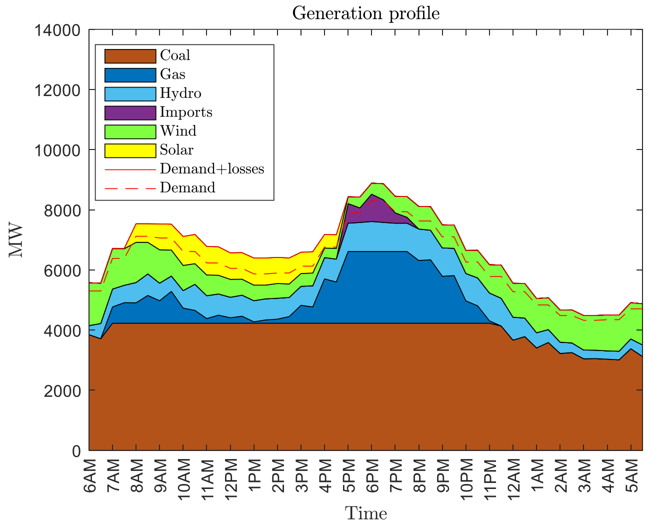

Figure 40: Generation profile under 50% SH and 50% DHW electrification for an average autumn demand day in 2025.

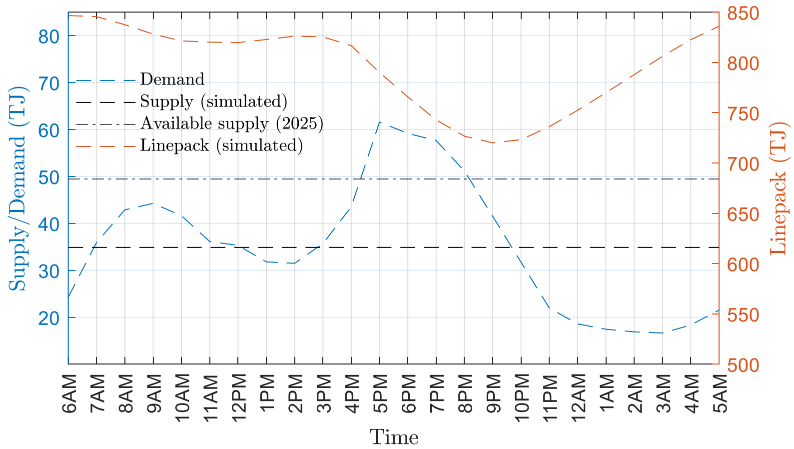

Figure 41: Linepack and gas supply profiles under 50% SH and 50% DHW electrification for an average autumn demand day in 2025.

3.5.3. 100% SH and 100% DHW

This “100% SH and 100% DHW” scenario is characterised by an average of 844 MW of wind power and a net gas demand (excluding gas consumed by GPGs) of 483 TJ/d. Compared to the base case, 424 TJ/d of energy from residential heating is shifted from the gas system to the electricity system. As a result, the electricity generation profile in Figure 42 shows that the shortfall in generation between 4:30PM to 10PM needs to be supplemented by imports from other states through the interconnectors. However, these imports exceed interconnector capacities by an average of 400 MW, which entails that an interconnector augmentation might be needed in principle. On the gas network side, the total gas demand (including gas consumed by GPGs) is 711 TJ/d. The hourly linepack profile, along with the demand and supply profiles for this scenario are shown in Figure 43, which also shows that the gas supply is adequate, as evidenced by an EoD linepack that is close to the BoD linepack target (see Section 2.3). Compared to the base case, the GPG demand increased by 191 TJ/d (from 37 TJ/d to 228 TJ/d), but this increase in GPG demand is offset by a larger decrease in residential heating demand for a total gas demand decrease of 233 TJ/d compared to the base case.

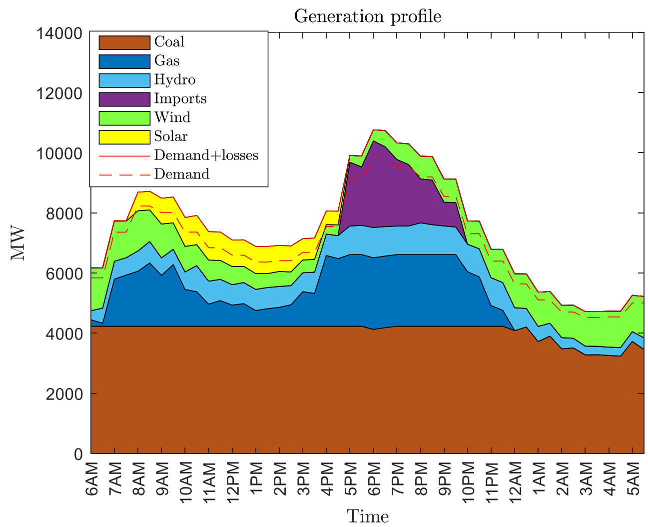

Figure 42: Generation profile under 100% SH and 100% DHW electrification for an average autumn demand day in 2025.

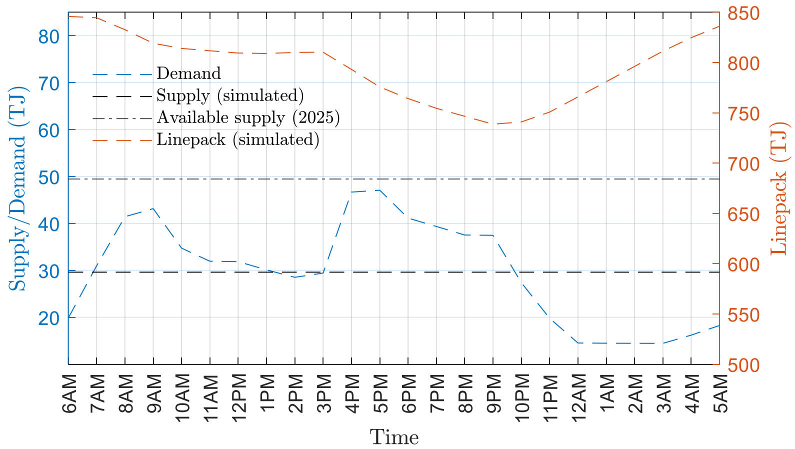

Figure 43: Linepack and gas supply profiles under 100% SH and 100% DHW electrification for an average autumn demand day in 2025.

3.6. CO_2 emissions (2025)

The CO_2 emissions for the five electrification scenarios in Section 3.1 to 3.5 are shown in Figure 44. The CO_2 emission factors of coal-fired generators and GPGs range from 1141 to 1315 kg/MWh and from 565 to 880 kg/MWh, respectively. Those emission factors are obtained from AEMO's Input and Assumptions Workbook 2019 [5] and are detailed in Table 3 and Table 4 in Appendix B. Moreover, the CO_2 emission factor of energy imports are assumed to be 464 kg/MWh to reflect the average emission factors of the generation mix of 2025 over NSW, Tasmania, and South Australia. The CO_2 emissions of NG are taken as 51.4 kg/GJ (or 185.03 kg/MWh) [22].

It can be observed from Figure 44 that, in the specific case of the Victorian part of the NEM and the Victorian DTS, the CO_2 emissions slightly *increase* with the level of electrification. More specifically, the decrease in emissions on the gas network side is offset by a larger increase in emissions on the electricity side as a result of electrification. The exact numbers depend on the level of RES injections, the synchronous generation mix (coal-fired and gas-powered generators), demand levels, and the topologies of both electricity and the gas networks. A further aspect to note is that, as electrified heating effectively becomes an additional marginal load, especially in winter, peaking generators with higher emissions will contribute more significantly to supplying the demand. Overall, under these conditions, the average emission factor of the online generators may be much higher than the average throughout the year.

To summarize, although the generation mix of 2025 includes a large share of RES capacity (see Section 2.2), shifting a large portion of heating demand from the gas system to the electricity system leads to more CO_2 emissions in total. This is also partially due to the curtailment of energy from RES due to a combination of transmission line thermal constraints, reserve requirements from coal-fired generators, and ramp rates, which lead to more dispatch of power from coal-fired generators and GPGs, and thereby increasing emissions.

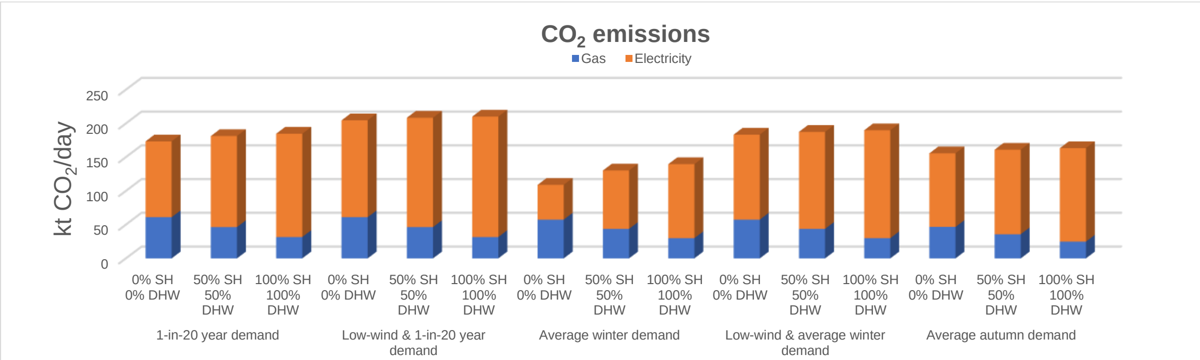

Figure 44: CO_2 emissions for the five electrification cases for 2025.

4. CONCLUSIONS

The capabilities of the developed IEGS modelling tool have been demonstrated by conducting the following illustrative studies on the Victorian integrated electricity and gas transmission systems:

- Assessment of gas supply adequacy of 2024 and
- Electrification of heating.

On the topic of gas supply adequacy of 2024, the tool has been used to illustrate that:

- Without imports from NSW through Culcairn, or an increase in capacity of committed gas supplies, AEMO's forecast of the shortfall in the Victorian gas supply for a 1-in-20-year peak gas demand day manifests in an EoD linepack that is significantly lower than the BoD linepack, which is not desirable as AEMO sets a BoD linepack target that accounts for the impact of unscheduled GPG demand and surprise cold weather. In extreme cases, such as the two consecutive 1-in-20-year peak gas demand days, the linepack swing can drop below a value that violates minimum pressure limits, which compromises the security of the gas system.

On the electrification of residential heating, the tool has been used to show that:

- The generation mix of 2025 is inadequate in most electrification cases (50% SH and 50% DHW and 100% SH and 100% DHW). However, in all the electrification test cases, the Victorian part of the NEM, with the 2025 augmentations of both the Western Victoria's electricity network and the interconnectors as per AEMO's ISP, can support electrification levels up to 50% SH and 50% DHW without requiring augmentations.
- The 100% SH and 100% DHW electrification scenario involving the 1-in-20-year peak gas system demand not only shows that the electricity network of Victoria witnesses inadequate generation, but also shows that (i) some interconnectors need significant augmentation and (ii) the electricity network requires augmentation in the form of up to 220% increase in MVA (thermal) capacity on some internal transmission lines.
- The gas supply is inadequate on a low-wind 1-in-20-year peak gas demand day with 50% SH and 50% DHW case. This shortfall in the Victorian gas supply manifests in an EoD linepack that is lower than the BoD linepack. In all the other cases the gas supply is adequate, as evidenced by an EoD linepack close to the BoD linepack, which is a desirable outcome as AEMO sets both the EoD and BoD linepack targets to values that maintain efficient and safe system operational conditions.

The key aim of this report is to showcase the capabilities of the modelling tool under development in conducting electrification studies, which are core studies identified in the RP1.1-02 project, and to underscore the importance of bottom-up integrated multi-energy sector, network, and system assessment with relatively high spatial and temporal resolution and suitable operating constraints, which is lacking in most if not all studies performed so far.

It should also be highlighted that the findings in this report should be considered for illustration purposes only and in the context of the specific assumptions made, rather than real guidelines for market stakeholders, for which specific studies based on agreed input data and assumptions should be performed.

5. IMPLICATIONS AND RECOMMENDATIONS FOR INDUSTRY

Once the IEGS tool presented here is fully developed, it could be used in applications such as:

- Assessing the flexibility of the gas network, as measured by the linepack, under different gas supply adequacy scenarios;
- Quantifying the impact of specific levels of electrification of SH and DHW gas demands on both the electricity and the gas networks in terms of (i) generation/gas supply adequacy, (ii) electricity/gas network flows, and (iii) CO_2 emissions. In these studies, the CoP of EHPs and the level of electrification can be straightforwardly modified to suit a variety of requirements.

6. NEXT STEP AND FUTURE WORK

The next step will consist of extending the above studies to the whole NEM and eastern gas transmission networks. This will require extending the electricity network model to the whole NEM and the gas network model to the whole gas transmission system of eastern Australia. The data collection will be facilitated by our industry partners.

In addition to the above developments, it should be considered that while the underlying modelling already generally reflects the operation of the NEM dispatch engine (NEMDE), although with a limited set of operating constraints that can be modelled with public information, there may also be potential added benefits in capturing the couplings between electricity and gas networks, gas network flexibility, and electricity and gas locational marginal prices (LMP) that reflect transmission line losses, all in an integrated optimisation framework.

Furthermore, and key to the next steps of the modelling development, the operational tool could be extended to a *planning* optimisation tool to support investment decisions identified in the future scenarios above.

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APPENDIX A: TRANSIENT GAS FLOW MODELLING

The dynamic behaviour of an isothermal gas flowing in a pipe is delineated by a set of three equations; namely, the state equation, the continuity equation, and the motion equation. The equation of state, which describes the relation between the gas pressure and density via the compressibility factor, is given by

$$\frac{p}{\rho} = ZRT = B^2, \tag{1}$$

where p [Pa] is the absolute pressure, ρ [kg/m^3] is the mass density, Z is the compressibility factor (dimensionless), R [J kg^{-1} K^{-1}] is the specific gas constant, T [K] is the absolute temperature, and B [m s^{-1}] is the isothermal speed of sound in gas.

The continuity equation, also known as the mass conservation equation, can be written as

$$\frac{B^2}{A}\frac{\partial M}{\partial x} + \frac{\partial p}{\partial t} = 0, \tag{2}$$

where M [kg s^{-1}] is the mass flow rate, A [m^2] is the cross-sectional area of the pipe, x [m] is the horizontal coordinate along the pipe, and t [s] is the time coordinate.

The equation of motion, which is derived from Newton's second law, is given by

$$\frac{\partial p}{\partial x}\left(1 - \frac{B^2M^2}{A^2p^2}\right) + \frac{pg}{B^2}\sin(\alpha) + \frac{fB^2M^2}{2DA^2p} + \frac{1}{A}\left(\frac{\partial M}{\partial t} + \frac{2B^2M}{Ap}\frac{\partial M}{\partial x}\right) = 0, \tag{3}$$

where g [m/s^2] is the gravitational acceleration, α is the pipe inclination angle with respect to the horizontal axis, f (dimensionless) is the Darcy-Weisbach friction factor, and D [m] is the diameter of the pipe. In this work, (1)-(3) are solved numerically using the finite difference method with a 5-minute time step and 3 discretisation points on each pipeline.

The linepack in each pipeline at every time step is given by

$$L_p = V\frac{\rho_a}{\rho_s}, \tag{4}$$

where L_p [m^3] is the linepack, V_p [m^3] is the pipeline physical volume, ρ_a [kg/m^3] is the gas mass density at actual flow conditions, and ρ_s [kg/m^3] is the gas mass density at standard conditions. It is convenient to express the actual density given in the linepack equation in terms of pressure and temperature. Therefore, using the equation of state described in (3), the linepack equation becomes

$$L_p = V\frac{p_a}{\rho_s Z_a R T_a} \tag{5}$$

The pressure, temperature, and compressibility factor are the average values for each pipeline segment, and they are given at actual flow conditions.

APPENDIX B: EMISSION FACTORS - 2025

This appendix shows the detailed emission factors of coal-fired generators and GPGs in Victoria in 2025 as per AEMO's Input and Assumptions Workbook 2019 [10].

Table 3: Emission factors of coal-fired generators in Victoria in 2025 as per AEMO's Input and Assumptions Workbook 2019 [5].

DUID	Station name	NEM region	Emissions (kg/MWh)
LOYYB1	Loy Yang B power station	VIC1	1141.02
LOYYB2	Loy Yang B power station	VIC1	1141.02
LYA1	Loy Yang A power station	VIC1	1154.82
LYA2	Loy Yang A power station	VIC1	1154.82
LYA3	Loy Yang A power station	VIC1	1154.82
LYA4	Loy Yang A power station	VIC1	1154.82
YWPS1	Yallourn 'w' power station	VIC1	1315.51
YWPS2	Yallourn 'w' power station	VIC1	1315.51
YWPS3	Yallourn 'w' power station	VIC1	1315.51
YWPS4	Yallourn 'w' power station	VIC1	1315.51

Table 4: Emission factors of GPGs in Victoria in 2025 as per AEMO's Input and Assumptions Workbook 2019 [5].

DUID	Station name	NEM region	Emissions (kg/MWh)
AGLSOM	Somerton power station	VIC1	817.92
JLA01	Jeeralang "A" power station	VIC1	879.40
JLA02	Jeeralang "A" power station	VIC1	879.40
JLA03	Jeeralang "A" power station	VIC1	879.40
JLA04	Jeeralang "A" power station	VIC1	879.40
JLB01	Jeeralang "B" power station	VIC1	879.40
JLB02	Jeeralang "B" power station	VIC1	879.40
JLB03	Jeeralang "B" power station	VIC1	879.40
LNGS1	Laverton North power station	VIC1	790.18
LNGS2	Laverton North power station	VIC1	790.18
NPS	Newport Power Station	VIC1	570.05
VPGS1	Valley Power Peaking Facility	VIC1	871.55
VPGS2	Valley Power Peaking Facility	VIC1	871.55
VPGS3	Valley Power Peaking Facility	VIC1	871.55
VPGS4	Valley Power Peaking Facility	VIC1	871.55
VPGS5	Valley Power Peaking Facility	VIC1	871.55
VPGS6	Valley Power Peaking Facility	VIC1	871.55
BDL01	Bairnsdale power station	VIC1	565.21
BDL02	Bairnsdale power station	VIC1	565.21
MORTLK11	Mortlake power station	VIC1	573.44
MORTLK12	Mortlake power station	VIC1	573.44

APPENDIX C: ELECTRIFICATION STUDIES FOR 2035

The studies herein consist of assessing the impact of electrification of residential heating on the electricity and gas networks of Victoria, under the "Central" scenario in AEMO's integrated system plan (ISP) for the year 2035. The Central scenario incorporates a 50% renewable energy target in Victoria (VRET) by 2030 and the Federal Government objective of reducing emissions by at least 26% by 2030.

The electrification studies are conducted for five different cases in 2035, namely, (i) 1-in-20-year peak gas system demand day, and (ii) low-wind 1-in-20-year peak gas system demand day, (iii) average winter gas demand day, (iv) low-wind average winter gas demand day, and (v) average autumn gas demand day. Each one of the five different electrification scenarios consists of three subcases where space heating (SH) and domestic hot water (DHW) gas demands are replaced with electric options: (i) 0% SH and 0% DHW, (ii) 50% SH and 50% DHW, and (iii) 100% SH and 100% DHW. In this work, air-to-water electric heat pumps (EHPs) are used in the electrification of DHW and air-to-air EHPs are used in the electrification of SH.

For comparison purposes, the same studies are also conducted for year 2025 under the same assumptions detailed below.

Assumptions

Residential gas demand profiles are based on the analysis in [1] and the assumptions in [2] and [3]. In more detail, SH and DHW demands are assumed to account for 75% and 23% of the residential gas consumption, respectively, whereas cooking demand accounts for 2% of the residential gas consumption and is assumed to be uniform between 5pm and 11pm [2],[3]. The normalised residential gas demand profile for a typical winter weekday is depicted in Figure 11.

The proportion of gas consumption in different sectors, excluding the gas consumed by gas-powered generators (GPGs), is shown in Table 2 [3],[4].

In all the electrification scenarios herein, the electrification of DHW is assumed to be enabled by *air-to-water* EHPs with a coefficient of performance (CoP) shown in Figure 45 for a water temperature of 50°C. The CoPs in Figure 45 are obtained from [5] for a size "0025" unit.

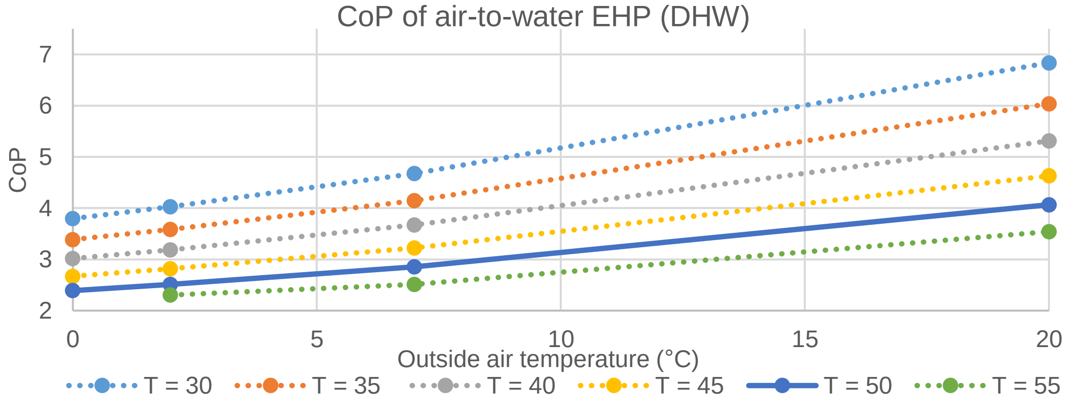

Figure 45: CoP of the considered air-to-water EHP used for DHW for different water temperatures ranging from 30°C to 55°C.

On the other hand, the electrification of SH is assumed to be enabled by air-to-air EHPs with a CoP shown in Figure 46. The CoP in Figure 46 is obtained from [6], page 31, for an air supply (shoot in) temperature of 30°C.

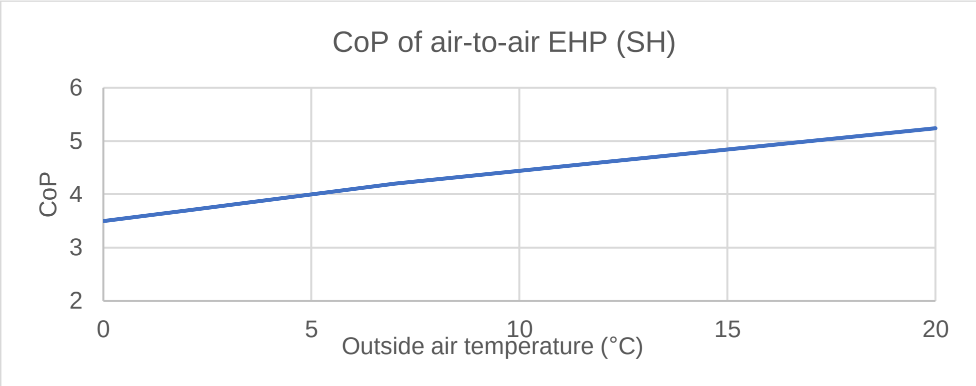

Figure 46: CoP of the considered air-to-air EHP for SH.

Outside temperature profiles for each demand zone are obtained from the Bureau of Meteorology [7] in a half-hourly resolution. Zonal gas demands are obtained from AEMO [8], under "Public D+3 Metering Data". Note that these zonal demands include the gas consumed by GPGs, which were then subtracted with the help of the metered power (MW) outputs obtained from AEMO's SCADA values [9] of the corresponding GPGs. Heat rates (GJ/MWh) of the corresponding GPGs are obtained from AEMO's Input and Assumptions Workbook 2019 [10].

CO_2 emissions (2035)

This section analysis the CO_2 emissions for the five different representative days in 2035. The CO_2 emission factors of coal-fired generators and GPGs range from 1141 to 1155 kg/MWh and from 565 to 880 kg/MWh, respectively. Those emission factors are obtained from AEMO's Input and Assumptions Workbook 2019 [10] and are detailed in Table 8 and Table 9 in Appendix D. Moreover, the CO_2 emissions factors of energy imports from neighbouring states (through the interconnectors) in 2025 and 2035 are assumed to be 56% and 42% of the emissions in 2020, respectively, as shown in Table 5, to reflect the average emissions factors of the generation mix of 2025 and 2035 over New South Wales (NSW), Tasmania (TAS), and South Australia (SA). The CO_2 emissions of natural gas are taken as 51.4 kg/GJ (or 185.03 kg/MWh) [11].

Table 5: Average CO_2 emissions factors for NSW, Tasmania, and South Australia in 2025 and 2035.

Direction of power flow	CO_2 Emissions (kg/MWh)	
	2025	2035
SA -> VIC	288.6	214.6
NSW -> VIC	464	345.0
TAS - > VIC	107.5	79.9

The average wind generation for the five representative days is shown in Table 6. Table 6 also shows the proportion of total wind energy cross the 24 hours for each representative day.

Table 6: Average wind generation and proportion of total wind energy cross 24 hours for each representative day in 2035.

	0% SH and 0% DHW		50% SH and 50% DHW		100% SH and 100% DHW	
Representative day (2035)	Avg. wind gen. (GW)	Prop. of wind en. (%)	Avg. wind gen. (GW)	Prop. of wind en. (%)	Avg. wind gen. (GW)	Prop. of wind en. (%)
1-in-20-year demand	3.21	52.5	3.31	47.5	3.38	42.9
Low-wind 1-in-20-year demand	0.41	6.7	0.41	5.8	0.41	5.1
Typical winter demand	4.04	63.2	4.17	58	4.27	53.2
Low-wind typical winter demand	0.52	8.5	0.52	7.4	0.52	6.6
Typical autumn gas demand	2.62	46.2	2.62	42	2.64	38.5

The CO_2 emissions for the five electrification cases for 2035 are shown in Figure 47, which indicates that:

- On the 1-in-20-year demand, average winter gas demand, and average autumn demand days, where the proportion of wind energy across the day exceeds 46% (in the 0% SH and 0% DHW scenario), the total CO_2 emissions remain roughly unchanged as the level of electrification increases. This is because the reduction in gas consumption due to electrification is offset by similar-magnitude emissions due to the increase in generation from coal and peaking gas generators to provide the required level of electricity.
- Although CO_2 emissions on low-wind days (less than 9% wind energy share) are higher compared to days with typical wind availability (more than 46% wind energy share), those emissions sightly decrease as the level of electrification increases. Since coal and gas-powered generators are already operating at near-maximum capacity to compensate for the lack of wind, the additional demand brought about by the electrification of SH and DHW is supplied by the interconnectors. Under the assumptions listed in Table 5, the shift in heating demand results in a smaller-magnitude increase in emissions on the electricity system compared to the decrease in emissions on the gas system, which explains the slight decrease in total emissions as the level of electrification increases.
- The total daily emissions are generally lower in 2035 compared to the ones in 2025 shown in Figure 48 (under the new CoPs in Figure 45 and Figure 46).[16] The exact numbers are listed in Table 7.

The exact numbers depend on the level of renewable energy injections, the imports through the interconnectors (the emissions in neighbouring states), the synchronous generation mix (coal-fired and gas-powered generators), demand levels, and the topologies of both electricity and the gas networks.

To summarise, although the generation mix of 2035 includes a large share of renewable energy capacity, shifting a large portion of heating demand from the gas system to the electricity system is met with little or no decrease in total CO_2 emissions in general. This is also partially due to the curtailment of energy from renewable energy sources due to a combination of transmission line thermal constraints, reserve requirements from coal-fired generators, and ramp rates, which lead to a high enough dispatch of power from coal-fired generators and GPGs, whose emissions cancel out the decrease in emissions on the gas system as a result of electrification.

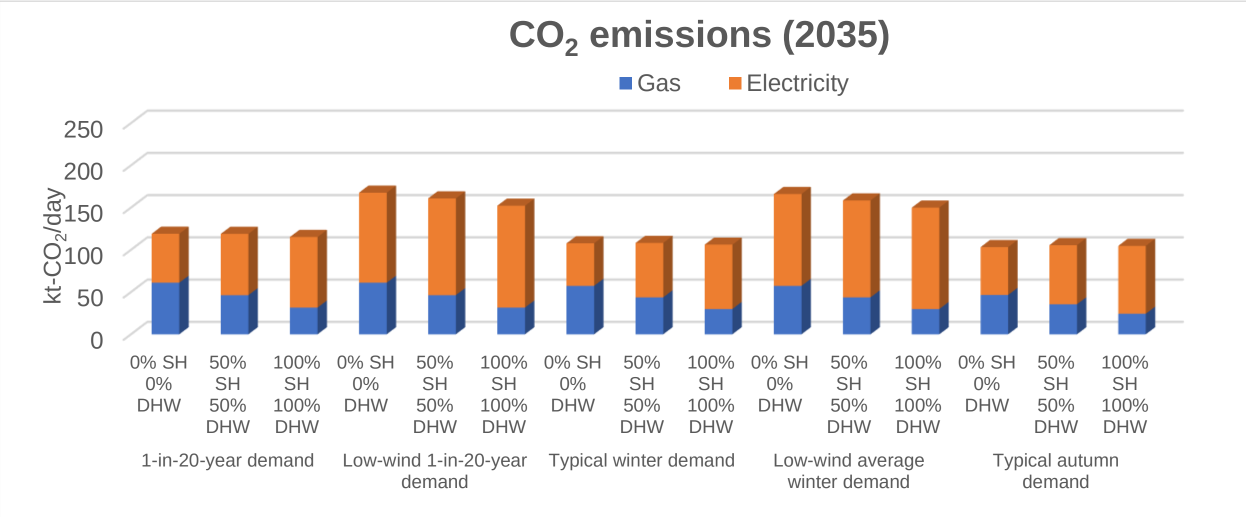

Figure 47: CO_2 emissions for the five electrification cases for 2035.

In an effort to quantify the sensitivity of the results to a change in the assumptions on the emissions in neighbouring states, the studies are extended to two additional scenarios where the emissions in Tasmania and South Australia were further reduced by 50% and 100% (zero emissions) of their values in Table 5. Those results are shown in Appendix E. The rationale behind assuming *zero* CO_2 emissions in South Australia and Tasmania is twofold. First both of those states are decarbonised at a higher rate compared to New South Wales, and second, the power they export to Victoria is mostly “green” power. In summary, the maximum decrease in emissions going from the assumptions in Table 5 to the ones in Table 7 is about 2.33% for 2025 and 3.55% for 2035. Those are witnessed on the low-wind days at the electrification level of 100% SH 100% DHW.

[16] It should also be highlighted that the findings in this report should be considered for illustration purposes only and in the context of the specific assumptions made, rather than real guidelines for market stakeholders, for which specific studies based on agreed input data and assumptions should be performed.

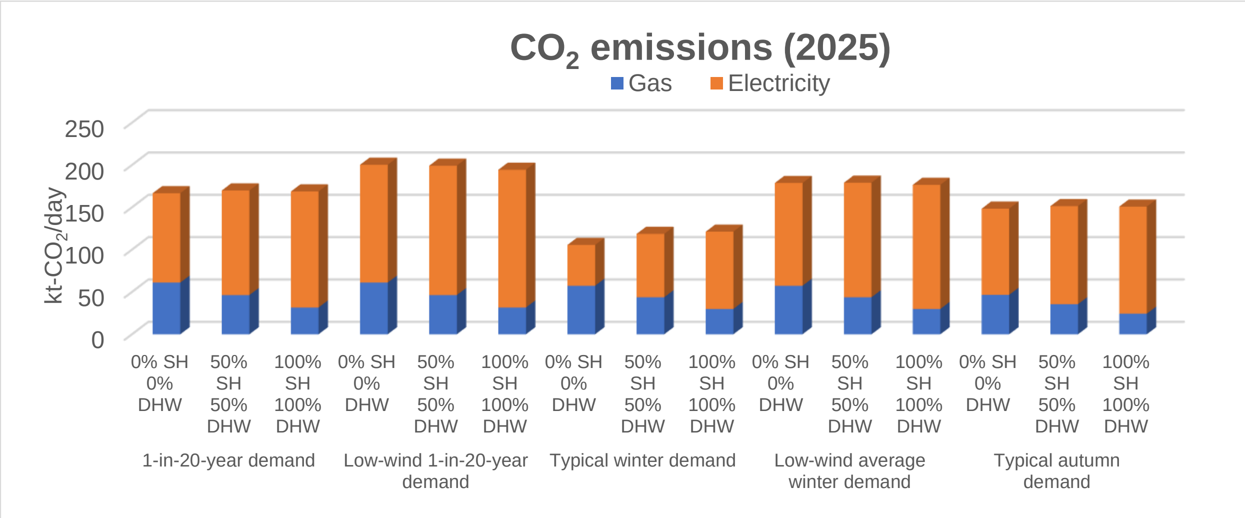

Figure 48: CO_2 emissions for the five electrification cases for 2025 under the new CoPs in Figure 45 and Figure 46.

Table 7: CO_2 emissions in 2025 and 2035 for the five representative days.

		Emissions (kt-CO_2/day)		Decrease (%)
		2025	2035	
1-in-20-year demand	0% SH 0% DHW	166.67	119.02	28.59
	50% SH 50% DHW	169.90	118.91	30.01
	100% SH 100% DHW	168.73	115.22	31.72
Low-wind 1-in-20-year demand	0% SH 0% DHW	200.25	167.70	16.25
	50% SH 50% DHW	199.21	160.93	19.22
	100% SH 100% DHW	194.40	152.19	21.72
Typical winter demand	0% SH 0% DHW	105.56	107.69	-2.02
	50% SH 50% DHW	118.62	108.18	8.80
	100% SH 100% DHW	121.25	106.12	12.47
Low-wind typical winter demand	0% SH 0% DHW	178.74	166.15	7.04
	50% SH 50% DHW	179.11	158.45	11.54
	100% SH 100% DHW	176.56	149.93	15.08
Typical autumn demand	0% SH 0% DHW	148.38	103.24	30.42
	50% SH 50% DHW	151.40	105.52	30.30
	100% SH 100% DHW	150.89	104.68	30.63

APPENDIX D: EMISSION FACTORS - 2035

This appendix shows the detailed emission factors of coal-fired generators and GPGs in Victoria in 2035 as per AEMO's Input and Assumptions Workbook 2019 [10].

Table 8: Emission factors of coal-fired generators in Victoria in 2035 as per AEMO's Input and Assumptions Workbook 2019 [5].

DUID	Station name	NEM region	Emissions (kg/MWh)
LOYYB1	Loy Yang B power station	VIC1	1141.02
LOYYB2	Loy Yang B power station	VIC1	1141.02
LYA1	Loy Yang A power station	VIC1	1154.82
LYA2	Loy Yang A power station	VIC1	1154.82
LYA3	Loy Yang A power station	VIC1	1154.82
LYA4	Loy Yang A power station	VIC1	1154.82

Table 9: Emission factors of GPGs in Victoria in 2035 as per AEMO's Input and Assumptions Workbook 2019 [10].

DUID	Station name	NEM region	Emissions (kg/MWh)
JLA01	Jeeralang "A" power station	VIC1	879.4
JLA02	Jeeralang "A" power station	VIC1	879.4
JLA03	Jeeralang "A" power station	VIC1	879.4
JLA04	Jeeralang "A" power station	VIC1	879.4
JLB01	Jeeralang "B" power station	VIC1	879.4
JLB02	Jeeralang "B" power station	VIC1	879.4
JLB03	Jeeralang "B" power station	VIC1	879.4
LNGS1	Laverton North power station	VIC1	790.18
LNGS2	Laverton North power station	VIC1	790.18
NPS	Newport Power Station	VIC1	570.05
VPGS1	Valley Power Peaking Facility	VIC1	871.55
VPGS2	Valley Power Peaking Facility	VIC1	871.55
VPGS3	Valley Power Peaking Facility	VIC1	871.55
VPGS4	Valley Power Peaking Facility	VIC1	871.55
VPGS5	Valley Power Peaking Facility	VIC1	871.55
VPGS6	Valley Power Peaking Facility	VIC1	871.55
BDL01	Bairnsdale power station	VIC1	565.21
BDL02	Bairnsdale power station	VIC1	565.21
MORTLK11	Mortlake power station	VIC1	573.43625
MORTLK12	Mortlake power station	VIC1	573.43625

APPENDIX E: EMISSION FACTORS IN TASMANIA AND SOUTH AUSTRALIA

This appendix reruns the studies but now under the emissions shown in Table 10, where the emissions in Tasmania and South Australia were further reduced by 50% of their value in Table 5. Furthermore, this appendix also reruns the studies under the emissions shown in Table 12 where the emissions in Tasmania and South Australia were further reduced by 100% of their value in Table 5.

Table 10: Average CO_2 emissions factors for NSW, Tasmania, and South Australia in 2025 and 2035. In this scenario, the emissions in Tasmania and South Australia were further reduced by 50% of their value in Table 5.

Direction of power flow	CO_2 Emissions (kg/MWh)	
	2025	2035
SA -> VIC	144.3	107.3
NSW -> VIC	464	345.0
TAS - > VIC	53.8	40

The resulting CO_2 emissions in 2025 and 2035 for the five representative days under the emissions in Table 10 are shown in Table 11. The maximum decrease in emissions going from the assumptions in Table 5 to the ones in Table 10 is 1.15% for 2025 and 1.74% for 2035. Those are witnessed on the low-wind days at the electrification level of 100% SH 100% DHW.

Table 11: CO_2 emissions in 2025 and 2035 for the five representative days under the emissions in Table 10.

		Emissions ($kt\text{-}CO_2/day$)		Decrease (%)
		2025	2035	
1-in-20-year demand	0% SH 0% DHW	166.67	119.02	28.59
	50% SH 50% DHW	169.87	118.87	30.02
	100% SH 100% DHW	168.08	114.81	31.69
Low-wind 1-in-20-year demand	0% SH 0% DHW	200.25	167.32	16.45
	50% SH 50% DHW	198.70	159.88	19.53
	100% SH 100% DHW	192.18	149.67	22.12
Typical winter demand	0% SH 0% DHW	105.56	107.69	-2.02
	50% SH 50% DHW	118.62	108.18	8.80
	100% SH 100% DHW	121.25	105.96	12.61
Low-wind average winter demand	0% SH 0% DHW	178.74	165.74	7.27
	50% SH 50% DHW	179.05	157.30	12.15
	100% SH 100% DHW	175.90	147.36	16.22
Typical autumn demand	0% SH 0% DHW	148.38	103.24	30.42
	50% SH 50% DHW	151.36	105.52	30.29
	100% SH 100% DHW	150.56	104.52	30.58

Table 12: Average CO_2 emissions factors for NSW, Tasmania, and South Australia in 2025 and 2035. In this scenario, the emissions in Tasmania and South Australia were further reduced by 100% of their value in Table 5.

Direction of power flow	CO_2 Emissions (kg/MWh)	
	2025	2035
SA -> VIC	0	0
NSW -> VIC	464	345.0
TAS - > VIC	0	0

The resulting CO_2 emissions in 2025 and 2035 for the five representative days under the emissions in Table 12 are shown in Table 13. The maximum decrease in emissions going from the assumptions in Table 5

Table 5 to the ones in Table 12 is about 2.33% for 2025 and 3.55% for 2035. Those are witnessed on the low-wind days at the electrification level of 100% SH 100% DHW.

Table 13: CO_2 emissions in 2025 and 2035 for the five representative days under the emissions in Table 12.

		Emissions ($kt\text{-}CO_2$/day)		Decrease (%)
		2025	2035	
1-in-20-year demand	0% SH 0% DHW	166.67	119.02	28.59
	50% SH 50% DHW	169.84	118.83	30.03
	100% SH 100% DHW	167.42	114.40	31.67
Low-wind 1-in-20-year demand	0% SH 0% DHW	200.25	166.93	16.64
	50% SH 50% DHW	198.18	158.84	19.85
	100% SH 100% DHW	189.96	147.14	22.54
Typical winter demand	0% SH 0% DHW	105.56	107.69	-2.02
	50% SH 50% DHW	118.62	108.18	8.80
	100% SH 100% DHW	121.25	105.80	12.74
Low-wind average winter demand	0% SH 0% DHW	178.74	165.33	7.50
	50% SH 50% DHW	179.00	156.15	12.77
	100% SH 100% DHW	175.24	144.79	17.38
Typical autumn demand	0% SH 0% DHW	148.38	103.24	30.42
	50% SH 50% DHW	151.33	105.52	30.27
	100% SH 100% DHW	150.24	104.37	30.53

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Future Fuels CRC

Enabling the Decarbonisation of Australia's Energy Networks

www.futurefuelscrc.com

info@futurefuelscrc.com

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