26th International Congress on Modelling and Simulation, Adelaide, SA, Australia, 30 Nov–4 Dec 2025
mssanz.org.au/modsim2025

Session E03 – Invited speaker

A simplified electricity system model for exploring least cost generation mixes

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Abstract: The least cost future electricity generation mix remains a contested issue in Australia and other countries. One contributor to the divergence of opinion is that finding the least cost generation mix consistent with known system requirements requires a complex modelling approach, typically implemented as a linear programming problem. A linear program can search for the least cost combination of electricity system assets that meets the required system constraints much faster than any other approach. However, the most sophisticated electricity models require large teams, large data sets and multi-model approaches. In contrast, more simplified models can be used to give reasonable approximations at much lower cost and effort but vary in their design. This paper seeks to design a simplified electricity model for determining least cost generation mixes. The key features of the model are determined by trading off solution time and significance of the results. The selected model has been made available in four software languages for electricity system modelling.

Keywords: *Electricity, system, optimisation, model*

1. INTRODUCTION

Electricity generation is a major contributor to greenhouse gas emissions and Australia and many other countries have set net zero by 2050 emission target for their economies. Given this challenge, there is a lot of interest in the electricity system's future generation mix. The complex nature of the electricity system means that least cost combinations of electricity generation assets can only be practically determined using mathematical programming methods. Partial solutions can be determined in a spreadsheet environment but only by first fixing one or more dimensions of the solution. However, we would ideally prefer all aspects of the solution to be free to gain a fully optimised solution.

Electricity system models based on linear programming can have a high degree of spatial, temporal and technical detail. They may seek to represent many different economic, physical and technical aspects of how the electricity system works. The opportunity to develop and apply such models and the large data sets they require is only available to organisations that can support a permanent team. Often, multiple models are used to explore the solution space at different temporal resolutions (AEMO, 2025). In Australia and other electricity systems around the world, such models need to be accurate as they underpin real investment decisions for entrepreneurs, system regulators and policy makers. However, this paper is concerned with simpler models that are more broadly applicable to a single user seeking to investigate broad questions about the generation mix, where some accuracy can be sacrificed for transparency and user-friendliness. Overall, the goal is to produce a simple electricity model that solves in around one hour for a reasonable level of accuracy using only public and regularly updated data sources.

The paper outlines a broad electricity system model for determining least cost generation mixes and reports on the outputs that have been used to select preferred model formulations based on trading off the significance of differences in model results versus solution time. Specifically, the paper explores linear versus mixed integer programming, different regional resolutions and duplication of the model in different software implementations.

2. METHOD

2.1. Model design

The most relevant models were reviewed to understand the commonalities and differences in features. These included Gilmore et al. (2023), Idel (2022), Zerrahn and Schill (2017 and 2018). We also considered an Excel spreadsheet-based model developed by Wonhas (2024). Zerrahn and Schill (2017) also include a useful review of the scope and resolution of other similar published models.

With the exception of the spreadsheet model, models capable of determining the generation mix but with reasonable operational detail have nearly equivalent objective functions, that is, to minimise capital and operating costs such that investment and time sequential operation of assets is jointly optimised. The key differences between the models were in a small number of constraint equations and the scope of the sets which define the spatial and temporal dimensions of the models. In the process of trialling different model designs, differences in equations between models were the least consequential in terms of solution time and output values. Given the lack of impact of different equation formulations, that topic is not explored here. Instead, the most impactful model design options were in relation to the number of regions in the model and linear versus mixed integer programming. We also explore how well the model results can be duplicated in different software.

The temporal detail of the model also has a very significant impact on solution time and results. However, this topic has been separately addressed in Green (2025). Based on this research, we have designed the model with a two-hourly time resolution, which was found to provide reasonable accuracy relative to shorter time steps but at a much faster solution time. The model has been designed, however, so that the time resolution can be easily altered by the user as desired by changing a single parameter so long as the required matching data is available.

2.2. Model description

The model is a linear program which minimises the cost of electricity supply in 2050 in meeting demand in all regions, r, by building and operating generation technologies, g, and storage technologies, s. Time steps, h, are by default every two hours for one year. Hydro is also available, but it is an existing asset with no prospect for new capacity building. Given their long asset lives, existing and committed pumped hydro and transmission are supplied to the model as existing capacity. Customer-owned batteries are also supplied as existing capacity, given their stock is constantly being replaced. Otherwise, besides these exceptions, all current generation is assumed to have been retired. Electricity supply is constrained to meet a minimum greenhouse gas emission intensity of 0.05tCO_2e/MWh. This level was chosen as a reasonable compromise between emission reduction and cost. The unknown variables and fixed data inputs or parameters are shown in Table 1 followed by the equations starting with the objective function at (1).

Table 1 Model variables and parameters

Variable Name	**Description**	**Parameter Name**	**Description**
TotalCost	Total cost of electricity supply in \$	$\mathrm{CaptureRate}_{\mathrm{Fossilg}}$	CO_2 capture rate applied to fossil fuel generation technologies, *Fossilg*
$\mathrm{SCap}_{s,r}$	Storage technology capacity in MWh	GVarOM_{g}	Generation variable operating and maintenance costs in \$/MWh
$\mathrm{GCap}_{g,r}$	Generation technology capacity in MW	$\mathrm{GFixedOM}_{g}$	Generation fixed operating and maintenance costs in \$/MW
$\mathrm{TxCap}_{r,rD}$	Transmission capacity in MW, region *r* to demand region *rD*	$\mathrm{SFixedOM}_{s}$	Storage fixed operating and maintenance costs in \$/MW
$\mathrm{Prod}_{g,r,h}$	Electricity production in MWh	$\mathrm{MaxAvailability}_{\mathrm{Fuelg}}$	Maximum annual availability rate
$\mathrm{Export}_{r,rD,h}$	Exports to demand regions in MW	$\mathrm{IBRCost}_{g}$	Remediation cost for non-synchronous inverter based resources in \$/MW
$\mathrm{SOC}_{s,r,h}$	Storage state of charge in MWh	$\mathrm{SConCost}_{s,r}$	Storage grid connection cost in \$/MW
$\mathrm{Char}_{s,r,h}$	Storage charge in MW	$\mathrm{FuelEmisFac}_{\mathrm{Fossilg},r}$	Fuel emission factor in tCO_2e/GJ
$\mathrm{Dischar}_{s,r,h}$	Storage discharge in MW	$\mathrm{RenCapMax}_{\mathrm{VREg},r}$	Maximum renewable capacity in MW
$\mathrm{HydroSOC}_{r,h}$	Hydro state of charge of storage in MWh	$\mathrm{ElecDemand}_{rD,h}$	Electricity demand over time step in MW
$\mathrm{HydroDischar}_{r,h}$	Hydro discharge in MW	SEff_{s}	Round trip electricity storage efficiency
Parameter Name	**Description**	TxLossFac	Transmission loss factor
dt	Proportional of one hour	$\mathrm{MinStableGen}_{\mathrm{Fuelg}}$	Minimum stable generation rate
$\mathrm{GCapCost}_{g}$	Annualised generation technology capital cost in \$/MW	$\mathrm{GConCost}_{g,r}$	Generator grid connection cost in \$/MW
$\mathrm{GRegFactor}_{g,r}$	Regional cost factor for generation technologies	$\mathrm{OpReserve}_{rn}$	Operating reserve requirement at peak demand by regional node, *rn* in MW
$\mathrm{SCapCost}_{s}$	Annualised storage capacity cost in \$/MWh	$\mathrm{PeakContribution}_{\mathrm{VREg},r}$	Contribution of variable renewable generation at peak demand
$\mathrm{SRegFactor}_{s,r}$	Regional cost factor for storage technologies	$\mathrm{PeakDemand}_{r}$	The highest demand by region experienced in the year
$\mathrm{TxCapCost}_{r,rD}$	Annualised transmission capacity cost in \$/MW	EmisIntensity	The average greenhouse gas equivalent emission intensity tCO_2e/MWh
$\mathrm{REZTxCost}_{r}$	Renewable energy zone transmission cost \$/MW	$\mathrm{VREprofile}_{\mathrm{VREg},r,h}$	Variable renewable energy generation, *VREg*, profile in MW/MW
$\mathrm{HydroChar}_{r,h}$	Hydro inflows in MWh	GJperMWh	Gigajoules per MWh
D_{s}	Nameplate storage duration	$\mathrm{HydroCap}_{r}$	Hydro capacity in MW
$\mathrm{TxCapExisting}_{r,rD}$	Existing transmission capacity in MW	$\mathrm{FOAKProjCap}_{g,r}$	Capacity of first-of-a-kind (FOAK) projects deployed in MW
$\mathrm{FuelPrice}_{\mathrm{Fuelg}}$	Fuel price in \$/GJ for fuel generation technologies, *Fuelg*	$\mathrm{FOAKProjCapCost}_{g,r}$	Annualised capacity cost of FOAK projects deployed \$/MW
$\mathrm{FuelEff}_{\mathrm{Fuelg}}$	Fuel efficiency expressed as the ratio of energy-out per energy-in	$\mathrm{ElecStoCapExisting}_{s,r}$	Existing electricity storage capacity in MWh
$\mathrm{CarbStoCost}_{\mathrm{CCSg}}$	CO_2 storage cost in \$/MWh for CCS technologies, *CCSg*	$\mathrm{ElecConvCapExisting}_{g,r}$	Existing electricity generation capacity in MW

$$
\begin{aligned}
TotalCost = {} & \sum_{g,r} GCap_{g,r} \times \left(GCapCost_g \times GRegFactor_{g,r} + GConCost_{g,r} + IBRCost_g\right) + \\
& \sum_{s,r} SCap_{s,r} \times \left(SCapCost_s \times SRegFactor_{s,r} + \frac{SConCost_{s,r}}{D_s}\right) + \\
& \sum_{Fuelg,r,h} Prod_{Fuelg,r,h} \times dt \times \frac{FuelPrice_{Fuelg}}{FuelEff_{Fuelg}} \times GJperMWh + \sum_{Fuelg,r} FuelConCost_{Fuelg} \times GCap_{Fuelg,r} + \\
& \sum_{g,r,h} GVarOM_g \times Prod_{g,r,h} \times dt + \sum_{g,r} GFixedOM_g \times GCap_{g,r} + \\
& \sum_{CCSg,r,h} CarbStoCost_{CCSg} \times Prod_{CCSg,r,h} \times dt + \\
& \sum_{VREg,r} REZTxCost_r \times GCap_{VREg,r} + \sum_{s,t} \frac{SFixedOM_s}{D_s} \times SCap_{s,r} + \sum_{r,rD} TxCap_{r,rD} \times TxCapCost_{r,rD} + \\
& \sum_{g,r} FOAKGCap_{g,r} \times \left(FOAKGCapCost_{g,r} + GFixedOM_g\right) \qquad (1)
\end{aligned}
$$

Supply-demand balance (over r, h)

$$\sum_{r1} Export_{r,r1,h} + \frac{ElecDemand_{r,h}}{(1 - TxLossFac)} \leq \sum_{g} Prod_{g,r,h} + \sum_{r2} Export_{r,r2,h} \times (1 - TxLossFac) + HydroDischar_{r,h} + \sum_{s} DisChar_{s,r,h} - \sum_{s} Char_{s,r,h} \tag{2}$$

VRE generation (over $VREg$, r, h)

$$Prod_{VREg,r,h} = VREprofile_{VREg,r,h} \times \left(GCap_{VREg,r} + GCapExisting_{VREg,r}\right) \tag{3}$$

Maximum generation of non-VRE generation (over $Fuelg$, r, h)

$$Prod_{Fuelg,r,h} \leq GGCap_{Fuelg,r} + GGCapExisting_{Fuelg,r} \tag{4}$$

Minimum stable generation (over $Fuelg$, r, h)

$$\left(GCap_{Fuelg,r} + GCapExisting_{Fuelg,r}\right) \times MinStableGen_{Fuelg} \leq Prod_{g,r,h} \tag{5}$$

Maximum availability (over $Fuelg$, r)

$$\sum_{h} Prod_{Fuelg,r,h} \times dt \leq MaxAvailability_{Fuelg} \times 8760 \times \left(GCap_{Fuelg,r} + GCapExisting_{Fuelg,r}\right) \tag{6}$$

Storage state of charge balance (over s, r, h)

$$SOC_{s,r,h+1} = SOC_{s,r,h} + (SEff_s^{\frac{1}{2}} \times Char_{s,r,h} - SEff_s^{-\frac{1}{2}} \times DisChar_{s,r,h}) \times dt \tag{7}$$

Storage initial and end state of charge

$$SOC_{s,r,h=1} \leq SOC_{s,r,h=lastperiod} \tag{8}$$

Maximum storage state of charge (over s, r, h)

$$SOC_{s,r,h} \leq SCap_{s,r} + SCapExisting_{s,r} \tag{9}$$

Maximum storage discharge on state of charge (over s, r, h)

$$DisChar_{s,r,h} \leq \frac{SOC_{s,r,h}}{dt} \tag{10}$$

Maximum storage discharge on capacity (over s, r, h)

$$DisChar_{s,r,h} \leq \frac{SCap_{s,r}}{D_s} + \frac{SCapExisting_{s,r}}{D_s} \tag{11}$$

Maximum storage charge on capacity (over s, r, h)

$$Char_{s,r,h} \leq \frac{SCap_{s,r}}{D_s} + \frac{SCapExisting_{s,r}}{D_s} \tag{13}$$

Hydro initial state of charge (over r)

$$HydroSOC_{r,h=1} = HydroChar_{r,h=1} \times dt \tag{14}$$

Hydro state of charge balance (over r, h)

$$HydroSOC_{r,h+1} \leq HydroSOC_{r,h} + HydroChar_{r,h} \times dt - HydroDischar_{r,h} \times dt \tag{15}$$

Maximum hydro discharge on state of charge (over r, h)

$$HydroDischar_{r,h} \leq \frac{HydroSOC_{r,h}}{dt} \tag{16}$$

Maximum hydro discharge on capacity (over r, h)

$$HydroDischar_{r,h} \leq HydroCap_r \tag{17}$$

Maximum exports on transmission (over s, r, h)

$$Export_{r,rD,h} \leq TxCap_{r,rD} + TxCapExisting_{r,rD} \tag{18}$$

Transmission symmetry (over r, rD)

$$TxCap_{r,rD} = TxCap_{rD,r} \tag{19}$$

Maximum VRE capacity (over *VREg, r*)

$$GCap_{VREg,r} \leq RenCapMax_{VREg,r} \tag{20}$$

Maximum emission intensity

$$\sum_{Fossilg,r,h} Prod_{Fossilg,r,h} \times dt \times \left(1 - CaptureRate_{Fossilg}\right) \times FuelEmisFac_{Fossilg,r} \times \frac{GJperMWh}{FuelEff_{Fossilg}} \leq EmisIntensity \times \frac{\sum_{rD,h} ElecDemand_{rD,h} \times dt}{1 - TxLossFac} \tag{21}$$

Minimum reserve margin (over regional nodes, *rn*)

$$OpReserve_{rn} \leq \sum_{r \in rn} \left[\begin{array}{c} \sum_{Fuelg} GCap_{Fuelg,r} + GCapExisting_{Fuelg,r} + HydroCap_r + \\ \sum_{VREg} PeakContribution_{VREg,r} \times \left(GCap_{VREg,r} + GCapExisting_{VREg,r}\right) + \\ \sum_{s} \frac{SCap_{s,r} + SCapExisting_{s,r}}{D_s} - PeakDemand_r \end{array} \right] \tag{22}$$

The model equations are common for electricity models that include a combination of generation, storage and hydro with endogenous investment (Zerrahn and Schill, 2017). The model uses annualised costs of capital and also adds interest lost during construction. The process of annualising the capital cost data requires additional parameters, including design life, construction time, and a discount rate or weighted average cost of capital.

Given our interest in 2050 and greenhouse gas emission reduction, Australia has three technology categories that present a challenge to include: Nuclear (large and small modular reactor), carbon capture and storage (coal and gas) and offshore wind (fixed and floating). The challenge they present is that while other countries can deploy these technologies efficiently, Australia's workforce has no installation experience. Therefore, specific to Australia's circumstances, the model accounts for first-of-a-kind (FOAK) costs that will be incurred if these FOAK technologies are deployed. In other words, these technologies are subject to a FOAK premium, if deployed. Nth-of-a-kind (NOAK) are where the local workforce is already skilled at deploying these technologies.

2.3. Data sources

Another key design aspect is that the model data should be from a small number of public and regularly updated sources so that the model data is transparent and easily updated. The three key sources are Graham et al. (2025), AEMO (2025) and DCCEEW (2024). All are publicly available as Excel files. The former two are updated every 6 months and the latter yearly. The mode also uses AEMO's published variable renewable energy (VRE) production profiles and demand profiles (net of rooftop solar generation), which are also regularly updated. AEMO (2025) and Graham et al. (2025) provide input data for three scenarios. The *Step Change* and *Global Net Zero post 2050* scenarios are used.

3. RESULTS

In evaluating the model design, the primary concern is a reasonable solution time while maintaining the accuracy of the model's calculated least cost generation mix for 2050. Average electricity cost is measured by summing all costs in the objective function and dividing them by useful generation (only generation used to meet demand and therefore excluding any spilled generation that are a feature of electricity systems that include VRE). The average electricity cost can be interpreted as the System Levelised Cost of Electricity (SLCOE) since it represents the annualised cost of all system cost items, including a return on investment.

Before commencing the model design options, a weather year was selected. The weather year changes the modelled cost of generation from weather-driven VRE and we wish to hold this factor constant while examining other design issues. Specifically, we chose the highest cost weather year as any system based on VRE should be designed to be reliable under worst-case weather conditions. Historical weather years for 2011 to 2023 were available. 2011 proved to have the highest SLCOE and, as a result, is our chosen weather year for all other model testing. The SLCOE range for all weather years was \$18.9/MWh to \$138.8/MWh with a standard deviation of \$5.5/MWh.

3.1. Linear versus mixed integer program formulation

For the model to endogenously determine whether to invest in technologies which are subject to a FOAK premium it must be formulated as a mixed integer program (MIP). In linear programs (LPs) different capital cost segments can be designed and included, but are only selected by the LP in order from lowest to highest cost. However, to deploy a FOAK technology, the high-cost version of that technology (i.e. the version with a FOAK premium) must be deployed first before gaining access to lower cost segments of the same technology. A MIP version of the model was created by introducing a binary variable B into those constraints which controlled maximum capacity that could be built. If the model selected B to be 1, the FOAK technology would be built at a FOAK premium cost, but also allow the model to access further capacity with no premium. Alternatively, if a value of 0 was selected by the model, then no capacity could be built, FOAK or otherwise.

A MIP with a two-hourly time step was first trialled but proved too slow to solve. A MIP with a four-hourly time step and a slightly reduced technology set solved in 38.5 hours (in GAMS using Gurobi as the solver). The LP version of the model can solve 4 scenarios in 40 minutes. Based on this outcome, it was determined that it is more efficient to use the LP to run four scenarios to explore the key technology options. The scenarios are:

- **NOAKTechOnly**: NOAK technology only
- **+CCS**: NOAK technology plus two CCS projects as a minimum (i.e. the model can choose to build more capacity at zero FOAK premium if it improves the objective function)
- **+Nuclear**: NOAK technology plus two large-scale and two small modular nuclear projects as a minimum
- **+OffshoreWind**: NOAK technology plus two fixed and two floating offshore wind projects as a minimum

The approach of including two FOAK technology deployments is consistent with Graham et al. (2025). The MIP model and the LP scenarios arrive at the same conclusion for the generation mix The MIP formulation did not choose to combine multiple FOAK technologies and as with the LP, preferred NOAK technology only. The SLCOE calculated by the MIP model was also within 3% of the LP model SLCOE.

3.2. 15 versus 5 region model

AEMO provides data on Australia's National Electricity Market (NEM) for 15 sub-regions that are part of 5 Australian states. A 15-region model is therefore the most accurate model formulation that can be serviced with reliable data. A faster model was tested by aggregating demand data to the 5 states level. However, the full range of VRE generation profiles from the 15 subregions were retained as available profiles for their respective states. The 5-region model solved the 4 scenarios in 9 minutes (using Gurobi). The results for these two models are compared in Figure 1 and Figure 2.

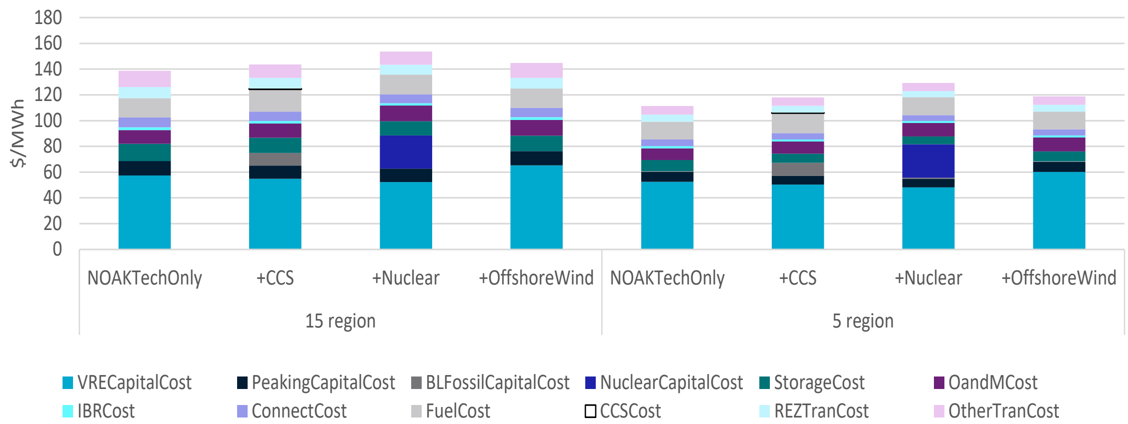

Figure 1 SLCOE for the 15 and 5 region models by cost component

The results demonstrate several differences between the 15 and 5 region models. The 5-region model calculates a SLCOE which is 16% to 20% lower than the 15-region model (Figure 1). The reduced costs are mainly in relation to peaking technology capital costs, storage capital costs and transmission costs. This indicates that in the absence of knowledge of hard transmission limits between the 15 sub-regions, the 5 region model does not see as much need for transmission, supply shifting and load following technologies. Both models only deploy close to the minimum amount of FOAK capacity in the +CCS, +Nuclear and +OffshoreWind scenarios, preferring to deploy the NOAK technologies of onshore wind and solar PV (Figure 2). The 5-region model has a stronger preference for wind generation which can only be accessed in specific locations and for that reason is more dependent on new transmission than solar PV.

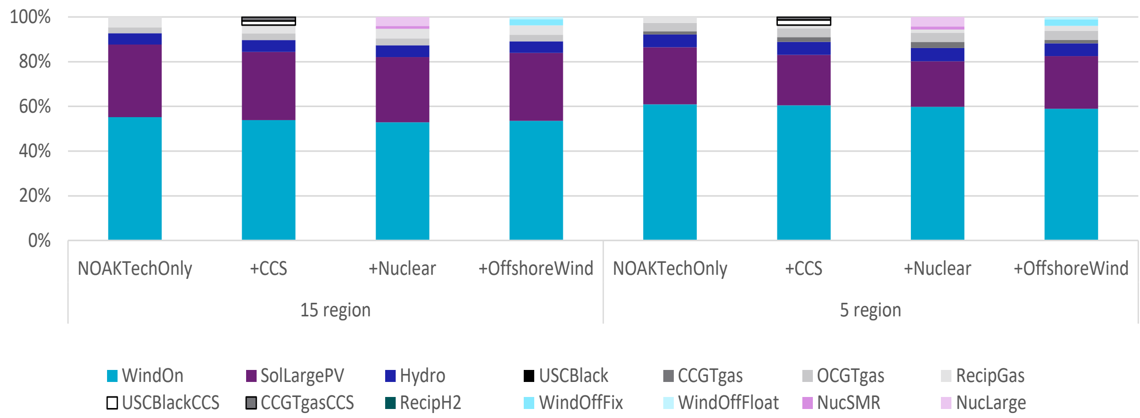

Figure 2 Electricity generation shares for the 15 and 5 region models by generation technology

3.3. Duplication of the model across four software packages

To support accessibility, the simple electricity model can ideally be deployed in a number of software packages and the relevant code made available. The final version of the model was implemented in four mathematical programming packages GAMS, JuMP, Pyomo and VEDA. Differences in costs and technology capacity solution values across all implementations were negligible. Solution times vary depending on the LP solver used.

4. DISCUSSION AND CONCLUSION

This paper reports the results of a model design process to determine the best formulation of a simple electricity model for exploring the least cost electricity generation mix in 2050. Features were tested for accuracy of the model and the solution time. Australia's circumstances call for the consideration of the inclusion of FOAK technologies in the generation mix. Consequently, a MIP formulation must be considered since it is the only way to implement an endogenous determination of the uptake of FOAK technologies. However, the modelling results found that a MIP formulation resulted in a solution time more than 50 times longer than an LP formulation. It was concluded that the LP formulation is the better trade-off since both models arrive at very similar solutions.

Versions of the model with 15 or 5 regions were implemented. The 5-region model ignores intrastate transmission constraints that create congestion in electricity supply and is solved in less than half the time of the 15-region model. However, the 5-region model resulted in an SLCOE that was 16%-20% lower reducing transmission, storage and peaking generation capacity deployment. This result is considered too inaccurate, and consequently, the reduced solve time of a 5-region model was considered a poor trade-off. Ultimately, the goal of creating a simple electricity model that solves in around 1 hour with readily available public data was achieved. A more detailed model description, the data files and software code are available for download at https://data.csiro.au/.

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