Energy Transformation Taskforce

Whole of System Plan Appendix A

Modelling methodology and assumptions

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Modelling methodology and assumptions

This appendix provides further detail on the modelling methodology used and assumptions made in the Whole of System Plan 2020 publication. It is intended to be read in conjunction with Appendices B and C.

Disclaimer

The information, representations and statements contained in this document have been prepared by the Energy Transformation Implementation Unit.

It is provided to assist in understanding the modelling approach being taken to develop the inaugural Whole of System Plan. The proposed modelling scenarios do not necessarily reflect government policy.

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Abbreviations

The following table provides a list of abbreviations and acronyms used throughout this document.

Term	Definition
AEMO	Australian Energy Market Operator
DER	Distributed Energy Resources
Dispatch model	The Market Dispatch Model
DSP	Demand Side Program
ESS	Essential System Services
ETIU	Energy Transformation Implementation Unit
LFAS	Load Following Ancillary Service
MW	Megawatts
NEM ISP	National Electricity Market Integrated System Plan
NPC	Net Present Cost
O&M	Operating and Maintenance
PFR	Primary Frequency Response
POE	Probability of Exceedance
RCM	Reserve Capacity Mechanism
RCT	Reserve Capacity Target
Resource planning model	The Transmission Network, Generation and Storage Resources Planning Model
RoCoF	Rate of Change of Frequency
RRN	Regional Reference Node
SCED	Security Constrained Economic Dispatch
SWIS	South West Interconnected System
Taskforce	Energy Transformation Taskforce
WEM	Wholesale Electricity Market
WOSP	Whole of System Plan

1. Background and context

The Whole of System Plan (WOSP) is a detailed study into the current state and the future of the SWIS. The plan has a 20-year outlook and presents a view on the transmission network, generation and storage investments that may be required to meet 4 possible future demand scenarios. It will be used to inform future infrastructure investment requirements, regulatory decisions, and policy and market development initiatives. The findings in the WOSP will also be used to help manage the security and reliability impacts of transitioning from traditional energy sources to new, lower emissions technologies.

Delivering the inaugural WOSP is the second component of the Western Australian Government's Energy Transformation Strategy to be delivered by the Energy Transformation Taskforce (the Taskforce). In order of delivery the three workstreams are:

- Distributed Energy Resources (DER)
- Whole of System Planning; and
- Foundation Regulatory Frameworks.

More information on the WOSP and other the Energy Transformation Strategy workstreams can be found on the Energy Policy WA (EPWA) website.[1]

The WOSP Project Team (the Project Team), comprised of representatives from EPWA, Western Power, Ernst & Young and the Australian Energy Market Operator (AEMO) have compiled the WOSP modelling assumptions, inputs and outputs over the next twenty financial years, commencing with the 2020-21 financial year. Inputs are as at May 2020 unless otherwise noted.

1.1 Stakeholder engagement

The WOSP modelling assumptions, inputs and outputs have been developed and tested via more than 120 meetings with over 40 energy sector stakeholders. This includes one-on-one meetings with industry participants, investors and advocacy groups.

Stakeholders have provided feedback on the modelling scenarios and various inputs and assumptions. In many cases, stakeholders have shared critical data such as operating costs, expected returns and plant characteristics. This information has helped to improve the quality of the WOSP modelling inputs and therefore the robustness of modelling outputs. The Taskforce appreciates the support provided by stakeholders and highlights that sensitive information provided by third parties will remain strictly confidential.

[1] https://www.wa.gov.au/organisation/energy-policy-wa/energy-transformation-strategy

2. Modelling methodology

The WOSP was developed using the outputs from two key models:

1. a transmission network, generation and storage resources expansion model (resource planning model); and
2. a market dispatch model (dispatch model).

For the WOSP modelling, the South West Interconnected System (SWIS) was split into 11 transmission network zones (or nodes) and each substation, point load, generator and storage facility on the network was allocated to one of the nodes.

The resource planning model was used to calculate total system costs and produce outputs to be used to inform the optimal transmission network, generation and storage investment plan that will allow SWIS demand to be met at the lowest sustainable cost in each scenario.

The dispatch model simulated the market outcomes in the WEM if the investment plan produced by the resource planning model was to be implemented. Together, these two models produced an indicative outlook of what power system and transmission network constraints may occur, what challenges/opportunities may arise, and what transmission network, generation and storage investments would be required under each scenario.

Where the initial investment plan produced by the resource planning model recommended generation or storage investments that the dispatch model subsequently determined would not be commercially viable (due to the resource planning model choosing investments that reduce overall system costs, as opposed to those that maximise individual investor returns) iterations between the two models have been required to determine an investment plan that meets system requirements at the lowest sustainable cost while also recommending commercially viable investment decisions.

Additionally, an AC load flow model has been used to verify the technical plausibility of the network investment plan.

Figure 2.1 provides an overview of the two models and how they interact.

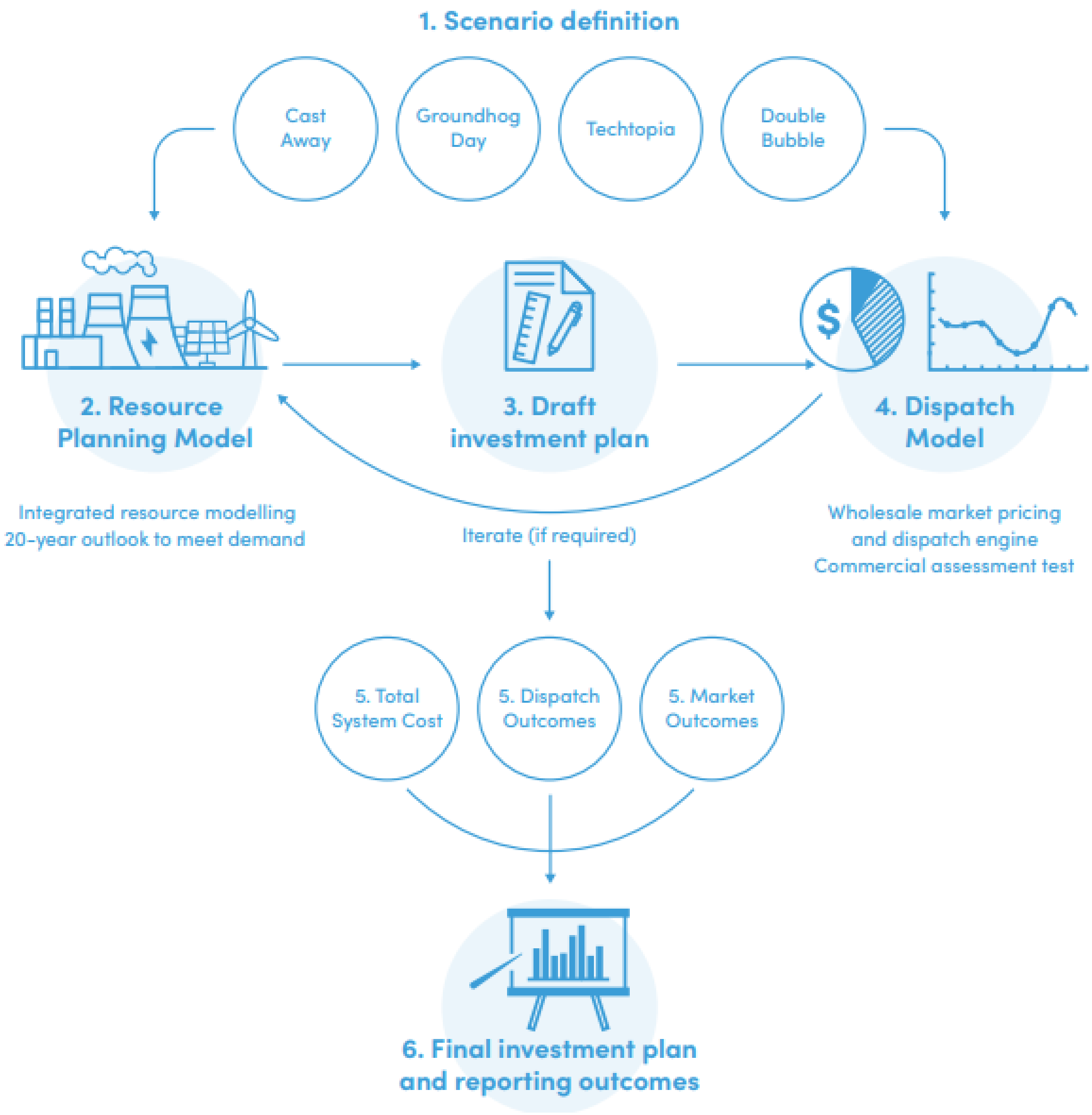


Figure 2-1: The WOSP modelling process

2.1 Resource planning model

The resource planning model is used to identify the lowest sustainable cost of new generation, storage and transmission infrastructure required to meet demand, reliability requirements and technical standards in each modelling scenario over the WOSP's 20-year outlook (2020-2040).

The model represents electricity supply and demand at the nodal level and produces time-sequential hourly dispatch for each individual generator and large-scale storage unit in the model. The same historical weather data used in the demand scenarios is used to model locational wind and solar generation output on an hourly basis in sync with weather dependent network demand.

The time-sequential demand data is used to generate a maintenance schedule for each installed thermal generator, assigning planned outages to periods of low demand. Forced outages are assigned to all generators using a Monte Carlo simulation based on assumed outage statistics. Due to the complexity and size of the optimisation problem, the resource planning model uses a single iteration of the Monte Carlo simulation of forced outages.

The model applies fixed inputs of demand, generator outages (planned and forced), wind and solar generation profiles, and the cost of new transmission network, generation and storage investment options, i.e. perfect foresight, whereas in the real world this is not the case. New investment options are defined in terms of capital costs, fuel costs, operation and maintenance costs, plant life, specific emissions characteristics and more.

The overall system cost is determined by calculating the Net Present Cost (NPC), that is the sum of capital expenditure, operation and maintenance costs (fixed and variable), fuel supply costs and unserved energy, over the entire 20-year study period. The NPC of transmission network, generation and storage supply is minimised by determining the least-cost generation dispatch for each interval for each power station along with the charging and discharging of storage.

Power stations are assumed to bid at their short run marginal cost, which is primarily related to fuel costs and variable operation and maintenance costs. The model assumes security constrained economic dispatch while incorporating other constraints including minimum loads, fuel availability, outages, network limitations, energy limits and the impact of essential system services (ESS) requirements.

Subject to annual scenario constraints and new entrant build limits, the resource planning model co-optimises transmission network, generation and storage investment to minimise the NPC over the 20-year study period by simultaneously making decisions on:

- commissioning new entrant generation and storage capacity for each defined technology type;
- augmenting the transmission network based on network augmentation options provided by Western Power, defined by a capital cost, the impact on power system or network transfer limits, asset life and build limits, if applicable; and
- retiring capacity where doing so will reduce the overall NPC while still allowing network demand, reliability requirements and technical standards to be met.

The model outputs are used to develop a network and generation investment plan for each scenario. The investment plan is a crucial input into the next modelling phase.

Figure 2-2 provides an overview of the inputs and outputs of the resource planning model.

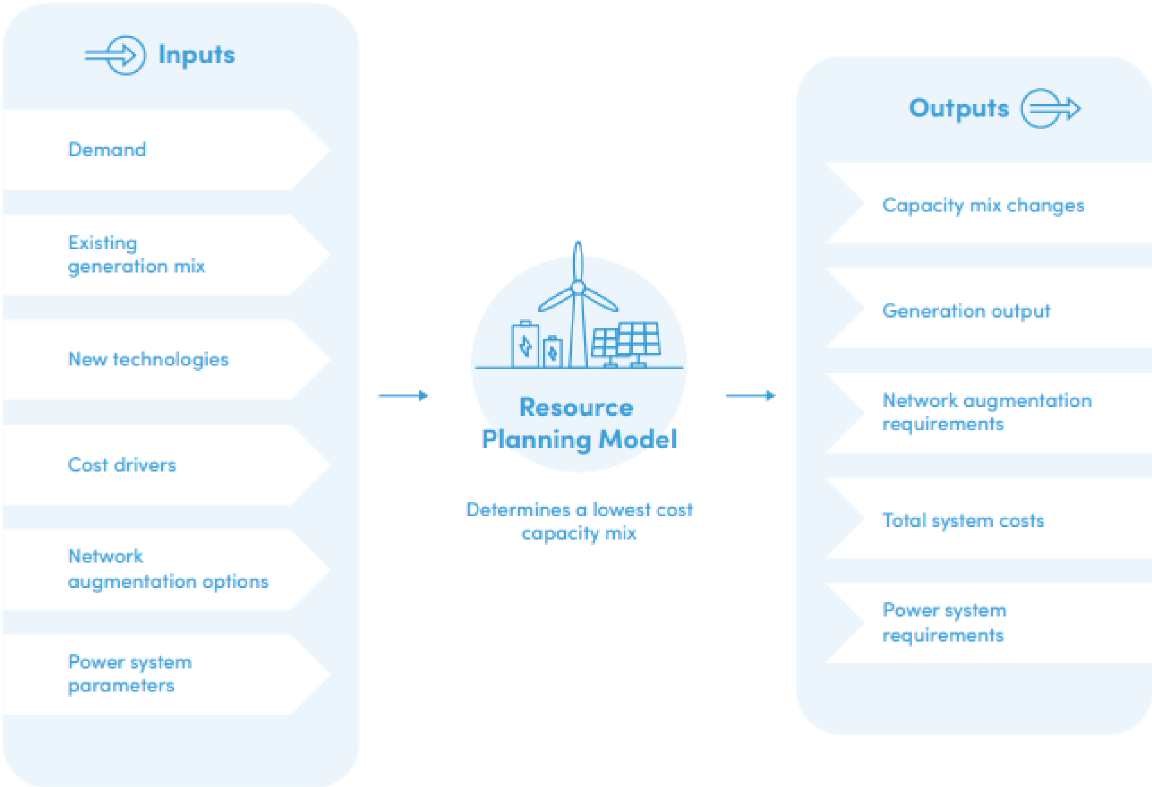


Figure 2-2: Overview of the network and generation resource planning model

2.2 Dispatch model

The market dispatch model simulates the market and dispatch outcomes of the investment plan produced by the resource planning model. The dispatch model seeks to replicate the functions of the WEM's real-time dispatch engine under new market arrangements being progressed as part of the Energy Transformation Strategy, and assumes the implementation of security constrained economic dispatch and co-optimised dispatch of energy and ESS markets for the entirety of the 20-year study period. Dispatch decisions are based on the principles of security constrained economic dispatch, considering generator bidding patterns and availabilities to meet regional demand and ESS requirements in each trading interval.

Modelling is conducted on a 30-minute interval resolution in a time-sequential manner, capturing the variability of renewable generation, thermal unit outages (both unplanned and planned) and ramp rate limitations, as well as underlying changes to system demand.

The dispatch model uses the same planned outage schedule as the resource planning model but can use a wider set of Monte Carlo simulations of forced outages to verify the robustness of the investment plan under a range of generator outage outcomes.

The dispatch model includes the operation of four ESS markets (Contingency Reserve Raise/Lower and Frequency Regulation Raise/Lower). The dispatch of ESS is co-optimised with energy dispatch to satisfy energy and ESS requirements at the lowest cost. The ESS dispatch constraints used in the dispatch model are the same as those used in the resource planning model.

The dispatch model determines capacity revenue by allocating Capacity Credits to capacity providers and determining a Reserve Capacity Price based on the capacity mix produced by the resource planning model. Capacity Credits are allocated to intermittent facilities based on the

Relevant Level Methodology. Storage facilities are allocated Capacity Credits for a percentage of their nameplate capacity, with a greater percentage being provided to facilities with longer-duration storage based on analysis of the allocation of capacity payments to storage facilities in other jurisdictions such as the UK and Ireland. 2-hour batteries are allocated Capacity Credits for 60% of their nameplate capacity, while facilities with 4-hour duration or longer are credited for 100% of their nameplate capacity.

Accordingly, the dispatch model is used to determine the commercial viability of the new entrant mix produced by the resource planning model's proposed transmission network, generation and storage investment plan under each scenario.

provides a high-level overview of the dispatch model.

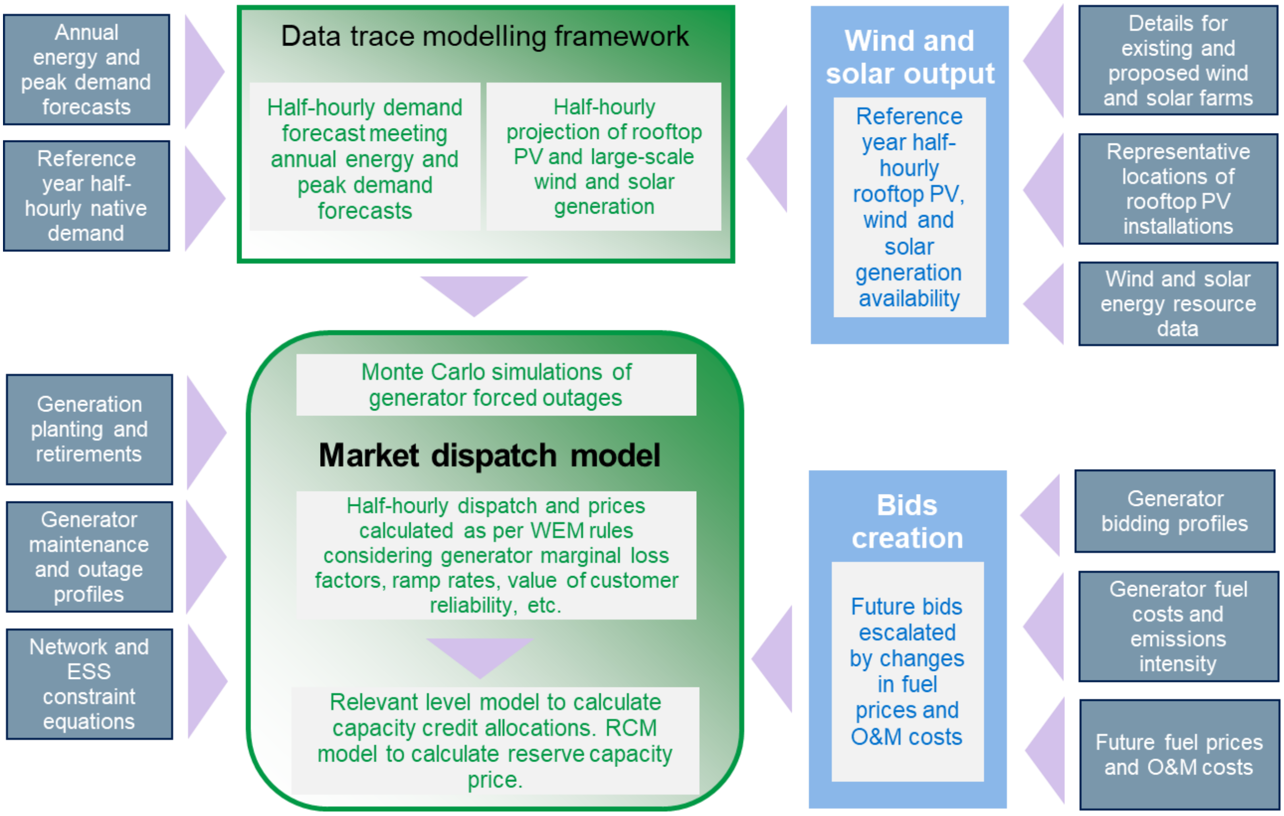


Figure 2-3: Overview of the dispatch model

Sensitivities on modelling inputs have been run in this WOSP to test the effects of parameter variability on the modelling outputs and the robustness of the commercial viability of new entrants.

3. Inputs and assumptions

The Project Team developed demand and supply side inputs and assumptions in consultation with industry that have informed the WOSP modelling. The key inputs and assumptions are:

- **Customer demand** – the forward-looking view of half-hourly demand in the SWIS over the next 20 years, taking into consideration the impact of distributed energy resources.
- **Network augmentation** – the approximate costs of network augmentation, including assumptions on transfer limits between transmission network zones.
- **Generator costs** – the cost assumptions of existing and potential new facilities.
- **Essential System Services** – system security constraints and estimated frequency regulation and frequency contingency requirements.

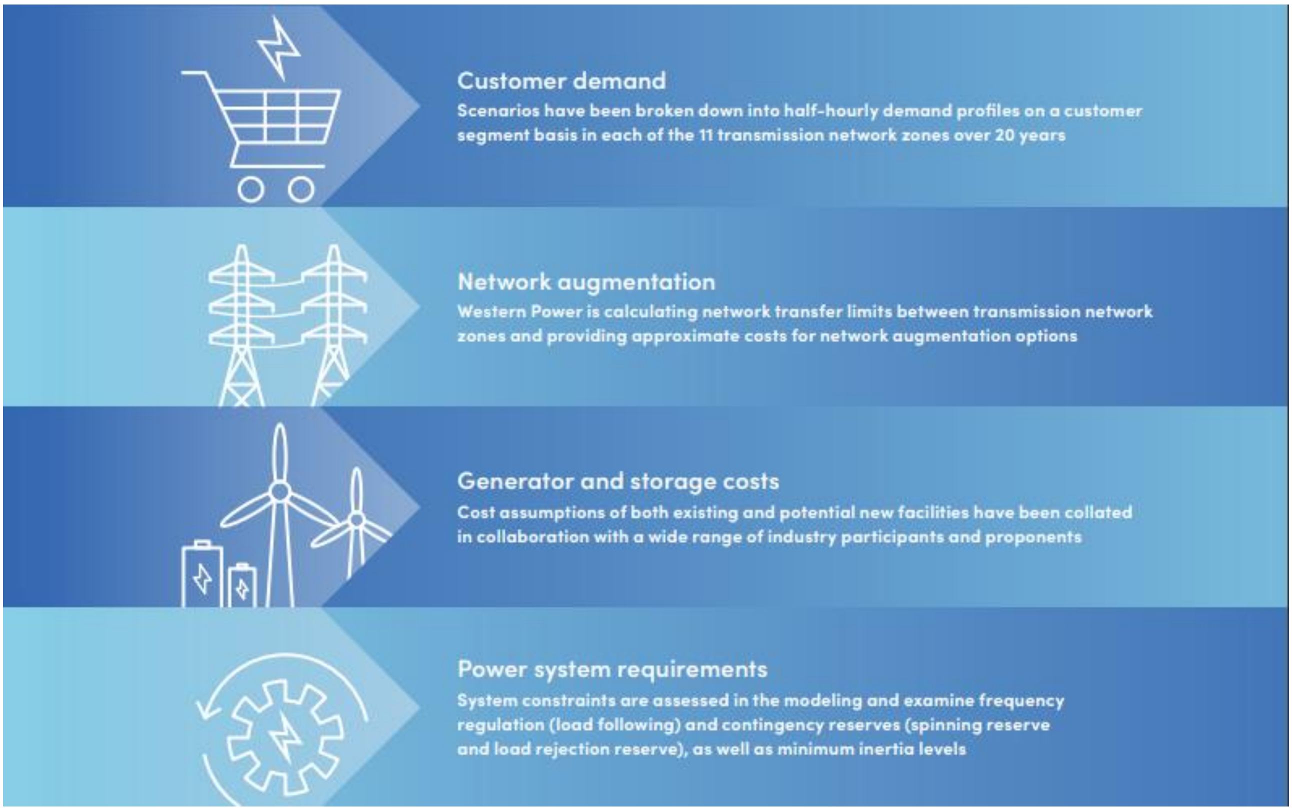


Figure 3-1: Key modelling inputs and assumptions

A Data and Assumptions Workbook is provided in Appendix B. The workbook provides an overview of inputs and assumptions, using publicly available data. Confidential and/or sensitive information provided by market participants has not been published.

3.1 Customer demand

For each scenario an estimate of demand for the next 20 years has been modelled. To provide a reasonable and robust estimate, the following steps were taken:

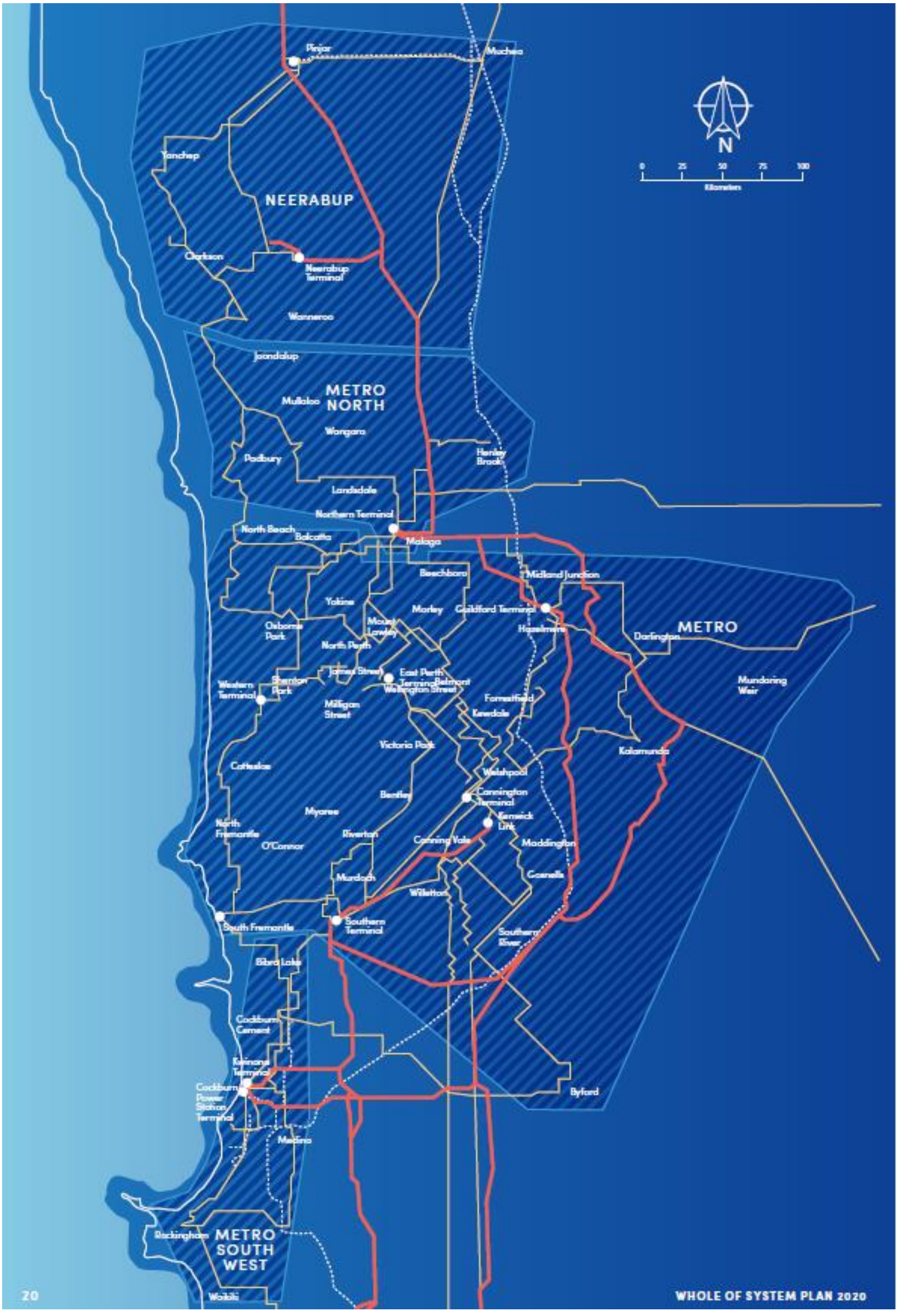
1. separated the SWIS into 11 transmission network zones (nodes) based on Western Power's planning areas and view of existing and likely network transfer boundary limits (as shown in Figure 3-2);

2. allocated customer demand to a substation or a point load[2], with over 108 substations and 600 point loads;
3. allocated substation/point loads' demand to one of the 11 SWIS nodes;
4. adjusted for seasonal demand within each node. This has been done for every 30-minute interval over 20 years. Nine weather reference years were available from the Bureau of Meteorology where the solar irradiance and the wind speeds in the SWIS were correlated on a 5 km and 12 km grid respectively. As such, a rooftop solar PV production profile was produced for the 108 unique Western Power zone substation connection points based on these nine years of historical solar irradiation data. The weather data has also been used to model wind generation on the supply side;
5. factored other forms of DER such as battery storage and electric vehicles into the demand forecasts, as well as additional point loads for the study period.

This nodal forecasting approach means the demand inputs consider electricity usage at the local level and can produce an estimate of future demand that is more likely to reflect customer's actual consumption behaviours than macro-level estimates. As discussed in the WOSP Industry Forum in July 2019[3], a range of economic, demographic and technological drivers and data sources were used to inform the demand estimates.

[2] A point load is a large load at a point on the network – generally associated with a commercial or industrial customer.

[3] https://www.wa.gov.au/sites/default/files/2019-08/Whole-of-System-Plan-Industry-Forum-Presentation-12-July-2019.pdf



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Northern Terminal
North Beach
Balcatta
Malaga
Beechboro
Midland Junction
Yokine
Morley
Guildford Terminal
Osborne Park
Mount Lawley
Hazelmere
METRO
Darlington
North Perth
James Street
East Perth Terminal
Belmont
Wellington Street
Mundaring Weir
Western Terminal
Shenton Park
Milligan Street
Forrestfield
Kewdale
Victoria Park
Kalamunda
Cottesloe
Welshpool
Bentley
Cannington Terminal
Myaree
Kenwick Link
North Fremantle
O'Connor
Riverton
Canning Vale
Maddington
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Southern Terminal
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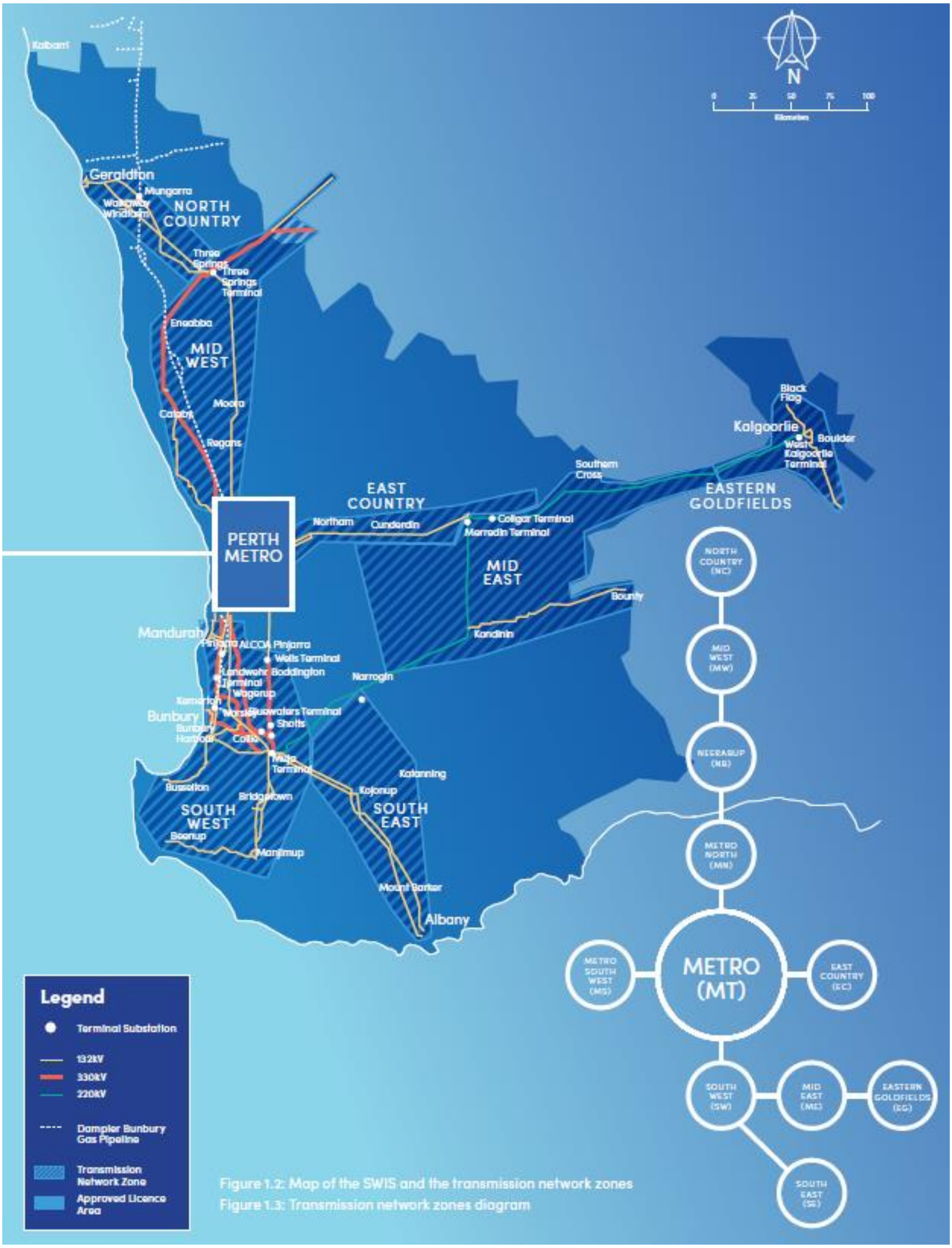

Figure 3-2: Map of the SWIS and the transmission network zones (nodes)

3.2 Network augmentation

A critical input into the WOSP is the potential cost of network augmentation. To ensure the WOSP modelling inputs (and ultimate outputs) are valid, Western Power has identified the existing transmission transfer capacity, or constraints, between the 11 SWIS transmission network zones (nodes). These are shown in Figure 3-3.

Western Power has also estimated the costs of augmenting the network to increase transmission transfer capacity between these nodes.

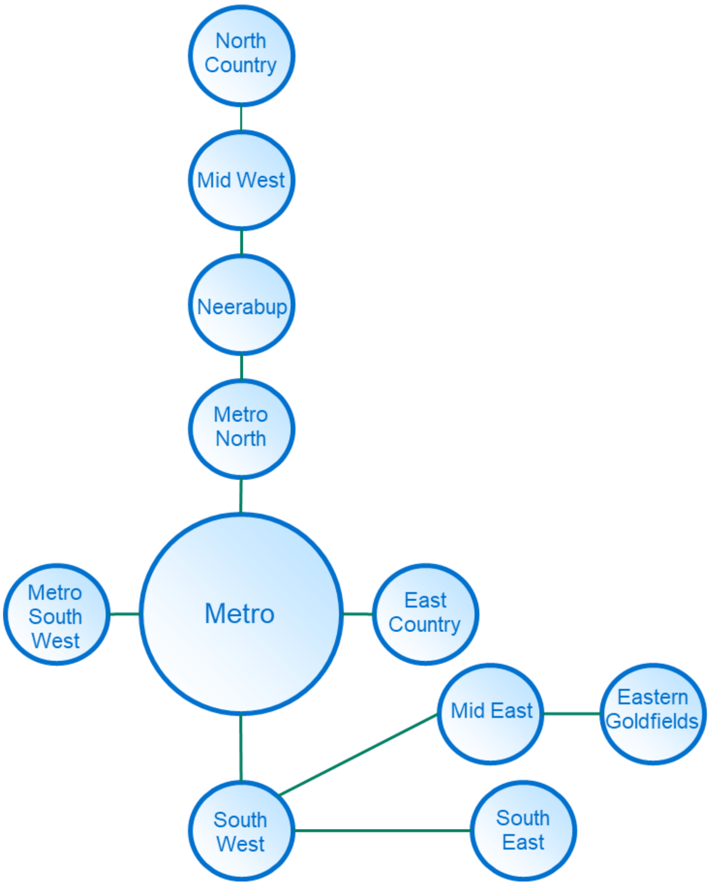

Figure 3-3: SWIS nodal resolution

3.3 Generator costs

The current and forecast costs of generators connected and expected to connect to the SWIS are important inputs into the WOSP. The ongoing cost of different generation types is critical data used to inform future investment decisions in the SWIS.

The Project Team conducted a series of one-on-one meetings with generators, to test a range of generation assumptions. For existing plant, assumptions tested with each owner include heat rates, ramp rates, start-up costs, fixed operating costs, and variable operating costs. Stakeholders have generally supported the fuel price outlooks and provided refined information on the operational parameters and costs for existing facilities.

The Project Team has also engaged with a number of infrastructure investors, who have shared their views on the risk adjusted returns on investment being experienced, risk appetite and access to funding. This information is aligned with the assumptions in the National Electricity Market Integrated System Plan[4] (NEM ISP) and has been used to inform the most appropriate rate of return inputs to apply to the WOSP modelling.

All sensitive information shared by third parties will remain strictly confidential. Data provided by market participants will be used for modelling purposes only and will not be retained for broader use by the Energy Transformation Implementation Unit following publication of the WOSP.

Where appropriate the WOSP has used NEM ISP assumptions for new plant as an initial assumption that has then been adjusted for local conditions. The types of new plant considered in the generation assumptions are:

- combined cycle gas turbine;
- open cycle gas turbine;

[4] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

- reciprocating gas engines;
- solar PV;
- battery storage;
- hydro and compressed air storage; and
- wind.

All existing generation facilities were modelled as well as committed generation projects, announced generator retirements and a pre-defined set of generation investment candidate options.

Whether a certain generation investment candidate technology is able to be built within a node is driven by its ability to reduce total system costs, subject to its technical, system and fuel assumptions.

To capture the benefits associated with diversity of generation supply technologies and the location of generation capacity, differences in locational connection costs, resource availability, and cost curves are modelled for different generation supply technologies. These can differ between the same technology type across different nodes.

The modelling includes flexibility for fixed generator retirements based on an input assumption (such as a fixed end of asset life based on age for different technologies) or by allowing the model to retire generation capacity endogenously based on costs. Both methods can also be used across different generating units within a generation facility.

Where generator retirements have been announced they are assumed to be committed. The modelling uses this information as an input assumption. Where existing generation assets have been selected as a retirement candidate, the model considers whether reducing the capacity of that asset at a particular point in time will result in a lower total system cost overall.

3.3.1 Forced (unplanned) outages

The resource planning model uses a single iteration of Monte Carlo outages to capture the impact of forced (unplanned) generator outages by assigning random outages to each generating unit based on assumed outage statistics.

The same outage statistics are typically applied for generators with the same fuel type. The characteristics of outages for wind and solar generators is different to large thermal generating units due to the modular nature of wind turbines or solar panels within a power station.

The capacity factors modelled for wind and solar farms are based on observed and expected output of the wind and solar farms modelled, and as such implicitly include the impact of outages (but not network constraints).

3.3.2 Planned outages (maintenance)

Generators tend to plan their maintenance in advance and with transparency, allowing all generators to manage the supply-demand balance as they are incentivised by the electricity market to schedule their maintenance at the time of lowest risk of high prices. They are also incentivised to avoid periods with a significant risk of very high peak demands in order to be eligible for Capacity Credits. Planned outages are also subject to AEMO’s outage approval process, which considers system security and supply adequacy over short and medium term planning horizons. This achieves a somewhat coordinated combined schedule of planned outages.

For each simulated financial year, the model applies an algorithm to assign maintenance schedules to each installed thermal generator (all generators fuelled with coal, gas or waste) to achieve a coordinated schedule. The algorithm is as follows:

- Calculate the daily operational peak demand for the future year
- Sort the installed thermal generators from largest capacity to smallest capacity
- Loop through each generator and assign its maintenance schedule (e.g., 20 sequential days) for a period where the risk of high prices is considered lowest. This lowest-risk period is chosen by looping through all the possible periods (e.g., 1-20 July, 2-21 July, and so on), calculating the maximum daily peak demand within each period and finding the one with the lowest maximum. This is based on the assumption that the higher the daily peak demand, the higher the risk of high prices on that day. With the lowest-risk period found, the daily peak demand is adjusted by adding on the capacity of that generator. This adjusted daily peak demand is used for the next generator, and so on, so that the chosen period for each generator takes into account the maintenance periods already assigned for the larger generators.

3.3.3 New entrant candidates

New entrant generation and storage investment candidate options are defined for each node. These are based on an assessment of available generation and storage technologies informed in part by connection applications made to Western Power and discussions held with AEMO.

The following areas are modelled for each new generation entrant candidate.

Capex

Each new entrant candidate option is modelled with a forecast of its capex cost across the study period to represent a forward looking cost curve. This cost is distinct from transmission network connection costs discussed below. Different technologies are forecast to have different cost reductions over time. For more mature technologies, these cost reductions are typically less material than for newer less mature technologies. The capex forecasts may differ for the same technology under different scenarios.

The resource planning model takes the total capex required for the generation or storage investment inclusive of connection costs as an input into its calculation when it determines whether investing in a certain generation or storage technology reduces the overall system cost. The cost to reinforce the transmission network to increase power transfer limits is also considered (discussed in section 3.2).

Connection costs

Connection costs are included for generation investment and represent the ‘plug-in’ costs required to connect the project to the Western Power Network. These costs do not include any shared network augmentation works as these are accounted for in the modelling of network augmentation candidates. The connection costs are expressed as a unit cost (in $/kW) and have been provided by Western Power. These costs have been informed by a number of recent connection cost estimates for connecting generation facilities to the SWIS. Different connection costs apply to different nodes, implemented through the use of a locational multiplier that accounts for differences in construction and labour costs, relative to other nodes.

Build limits

Generation build limits are modelled for nodes where certain constraints may preclude a certain technology from being built. The entry of certain technologies may be constrained by physical limitations such as land availability, access to fuel supply infrastructure or the necessary terrain to make a project technically viable (e.g. pumped hydro in the SWIS or large-scale wind farms in the metropolitan area may be subject to land availability). Generation technologies are also modelled with an earliest construction delivery estimate to account for longer lead times associated with certain technologies.

Renewable generation

The historically observed inter-temporal and inter-spatial impact of weather patterns are maintained in the future modelling. Historical hourly locational wind and solar resource data is used to model generation from rooftop PV, large-scale solar PV and wind.

All the correlated interactions between wind and solar generation at different sites are projected forward consistently, reflecting the impact of actual weather patterns. The available half-hourly large-scale wind and solar PV generation profiles are offered into the market to meet grid demand. These may not be fully dispatched in case of binding network constraints or being the marginal generator and setting the price, with the volume above the marginal price being curtailed.

Wind resource availability

Wind generation profiles have been developed for existing and future potential wind power stations, using historical hourly short-term wind forecast data from the Bureau of Meteorology (BOM) on a 12 km grid across Australia.

The BOM wind speed data is scaled for a site which is processed through a typical wind farm power curve to target a specific available annual energy in the half-hourly profile for each wind farm. The scaling is usually required to convert the modelled wind speed to the representative wind speed received by the wind farm.

Existing wind farms use the historical average achieved annual energy from actual data, while all new wind farms use an assumed annual energy that varies depending on their location in the SWIS.

Solar resource availability

Solar generation is simulated using historical hourly satellite-derived solar irradiation data on a 5 km grid across Australia, obtained from the BOM, along with BOM weather station data of temperature and wind speed.

The resource data from the BOM is processed using the System Advisory Model from the National Renewable Energy Laboratory to develop locational solar PV generation profiles. The annual energy output varies from site to site as a result of calibration to the performance of existing solar farms and the locational resource data as well as assumed design characteristics such as tracking and the DC to AC ratio.

Other generation

Thermal generation

All existing thermal generation facilities are modelled using a combination of publicly available data sources and data received from market participants. Thermal generation is modelled taking into consideration generator ramp rates, heat rates, cost parameters, fuel supply, and auxiliary and emissions factors.

New entrant thermal generation such as open-cycle gas turbines, combined cycle gas turbines, flexible gas technologies and coal-fired generation are modelled as candidate options as well.

Other supply options

Other new entrant candidate supply options include large-scale storage technologies and demand side management options. Different forms of large-scale storage technologies are modelled based on differences in cost curves and technical characteristics such as round-trip efficiency, depth of discharge and energy storage multiples.

3.3.4 Gas supply constraints

Constraints equations have been implemented in the resource planning model to account for gas supply constraints on the Dampier to Bunbury pipeline and the Eastern Goldfields gas pipeline, used to supply certain nodes in the SWIS. These constraints limit the amount of daily gas that can be used for gas fired generation in the SWIS.

The Project Team met with the pipeline owners and discussed available quantities of gas in the transmission system. The Project Team noted that there may be constraints at peak times and included an additional capital item on new gas to allow for lateral storage sufficient to ride through peak constraints.

A daily gas usage limit on new entrant gas generation was modelled. This set a maximum daily gas usage amount applied to the nodes supplied via the Dampier to Bunbury pipeline. This effectively limited the cumulative usage in a day. This number fluctuated across the study period depending on forecast consumption from AEMO’s GSOO.

Additionally, any gas unit built in the South West node incurred an additional capex cost to account for needing to reinforce gas infrastructure to the region.

Limitations on gas availability in the Eastern Goldfields region meant new entrant gas generation was only made available in the model when existing gas generation capacity was retired in the region.

For detailed information on modelling inputs, refer to the Data and Assumptions Workbook provided in Appendix B.

3.4 Essential System Services

As the generation capacity mix in the SWIS transitions to more intermittent, non-controllable and non-synchronous technologies, the means by which ESS are provided will change over time, as will the costs. The WOSP therefore includes consideration of how ESS requirements impact total system costs, generation dispatch and the generation capacity mix over the 20-year study period.

The WOSP assumes that the dispatch of the frequency control ESS markets will remain similar in principle to AEMO's current practice. Units capable of providing the frequency control ESS are dispatched to meet the requirements set in the ESS markets.

The resource planning model implements dispatch constraints on generation facilities capable of providing each service such that an amount of capacity for the Frequency Regulation and Contingency Reserve services is procured for each dispatch interval.

A predefined merit order is set based on an assessment of historical offer profiles for independent power provider units capable of providing the services and marginal cost-based offers for portfolio providers and new entrants. These units are committed to provide the services in the model using operational constraints imposed to ensure a facility is dispatched sufficiently above its minimum output or below its maximum output to be able to provide its offerings into the market.

The following ESS have been modelled in the WOSP:

- Frequency Regulation Raise (currently referred to as LFAS up)
- Frequency Regulation Lower (currently referred to as LFAS down)
- Contingency Reserve Raise (currently referred to as spinning reserve)
- Contingency Reserve Lower (currently referred to as load rejection reserve).

3.4.1 Essential system services in the resource planning model

The resource planning model optimises what generation, transmission network and storage to build, and when to build it, giving consideration for the unique impact and benefits that varying generation technologies have on energy and capacity requirements as well as system security. By considering ESS in the resource planning model, the WOSP:

- Considers the advantages and disadvantages that different supply technologies may have on ESS requirements in the future and the costs associated with ensuring ESS requirements are met.
- Values the unique performance characteristics available from different technology types and their ability to meet future ESS demands.
- Takes into account the impacts and benefits that behind the meter DER has on ESS requirements.
- Ensures dispatch of generation facilities are least cost and also able to operate within the technical envelope set by system operators.

The modelling approach has been broadly aligned with the ESS frameworks proposed in the Delivering the Future Power System[5] project in the Energy Transformation Strategy.

Key assumptions when modelling ESS in the WOSP are outlined below.

- **Frequency Regulation** – the Frequency Regulation service is dispatched to meet a dynamic requirement that is set in the market (defined in megawatts (MW) and changing depending on the time of day). The Frequency Regulation requirement in each of the scenarios is dependent on the generation mix outcomes from the resource planning model and assumptions around DER uptake for that scenario. This is driven by the observation that increased penetration in intermittent generation from rooftop PV and utility-scale wind and solar farms will lead to increased volatility in system frequency and, consequently, higher Frequency Regulation requirements.

[5] Part of the Foundation Regulatory Frameworks workstream.

- **Contingency Reserve Raise –** the WOSP dispatch model has implemented dispatch constraints to ensure generators are available to provide primary frequency response (PFR**)** in the event of a sudden loss of supply. The WOSP modelling for Contingency Reserve Raise is aligned with the new ESS framework being progressed as part of the Energy Transformation Strategy, and includes consideration of the crucial role of system inertia and speed of response of PFR providers in maintaining system security.
- **Contingency Reserve Lower –** the dispatch of the Contingency Reserve Lower service in the SWIS has been assumed to remain similar to the current practice in the WEM for all scenarios, dispatched to meet a requirement defined in MW, that is set as a function of system load.

3.4.2 Essential system services in the dispatch model

The dispatch model takes outcomes associated with ESS from the outputs of the resource planning model for use as inputs into a co-optimised energy and ESS market model. Facilities that can provide ESS are dispatched based on marginal pricing with co-optimisation of energy and ESS against transmission thermal constraints. The same four ESS markets that are modelled in the resource planning model are modelled in the dispatch model.

A clearing price for each ESS market is reported, including cleared quantities for each market on a time-sequential, half-hourly basis.

By considering ESS markets in the dispatch model, the WOSP:

- Provides a view of the potential size of the different ESS markets over the study period under different scenarios.
- Considers the additional revenue available from ESS markets for individual generation and storage facilities that may be needed to help investment cases.
- Ensures dispatch of generation facilities adequately provides Contingency Reserve and Frequency Regulation requirements when considering market outcomes.

A high level overview of the ESS market modelling is shown in Figure 3-4: ESS market modelling.

Figure 3-4: ESS market modelling

ESS requirements

The ESS requirements that are used within the dispatch model are produced from the resource planning model in a half-hourly time-sequential trace.

ESS offers

An offer curve is produced for each facility that is eligible to participate in the different ESS markets. Each facility is able to offer up to ten price-quantity pairs.

The offer curve for each facility is based on a combination of short run marginal cost and opportunity cost offering profiles consistent with the set of data inputs and assumptions used for facilities in the resource planning model.[6]

Different offer profiles are constructed depending on which ESS market is being modelled based on 'trapezium offer profiles' as described for the National Electricity Market (NEM).[7]

ESS revenue and cost

ESS revenues and costs are calculated and allocated to individual facilities on a half-hourly basis, based on their cleared quantities and simplified cost allocation rules for the purpose of the commerciality assessment.

3.5 Other modelling considerations

3.5.1 The Energy Transformation Strategy

Over the next three years, the Energy Transformation Strategy will implement a number of market reforms, which will have a direct bearing on the forthcoming and future iterations the WOSP. While it is not possible to factor in all of the proposed market design elements into this inaugural WOSP, key design elements have been incorporated in the modelling where practicable.

Table 3.1 presents an overview of the treatment of key market design elements in the inaugural WOSP.

Table 3.1: Summary of key Energy Transformation Strategy design elements and their treatment in the inaugural WOSP

Element	**Treatment in the WOSP**
Aggregated DER	Supply side storage and solar are forecast as generic MW/MWh volumes and could be provided by aggregators.
Co-optimisation of energy and ESS	Co-optimisation of energy and ESS requirements is modelled within both the resource planning and dispatch models.
Demand side program (DSP)	DSP is modelled as voluntary load shedding in response to high pricing events. Available DSP capacity is offered at the price cap and is dispatched before load is involuntarily shed.
Dispatch interval	The timeframe available for modelling precludes the development of five-minute input data for the four scenarios. The computational requirements for solving the same algorithm for the 60-minute (resource planning model) and 30-minute (dispatch model) modelling over a five minute time-step are also substantially larger.

[6] Opportunity costs are being considered in the dispatch modelling. See section 3.2.2 of the Energy Transformation Taskforce – Essential System Services Scheduling and Dispatch: https://www.wa.gov.au/sites/default/files/2019-12/Information%20Paper%20-%20ESS%20Scheduling%20and%20Dispatch%20_final.pdf

[7] Guide to Ancillary Services in the National Electricity Market - https://www.aemo.com.au/-/media/Files/PDF/Guide-to-Ancillary-Services-in-the-National-Electricity-Market.pdf

Element	Treatment in the WOSP
	Modelling a 5-minute dispatch cycle is unlikely to produce materially different outcomes for the purposes of the WOSP.
Energy storage	It is assumed that registration in a new Facility Class enables storage facilities to submit offers to charge and to discharge in the energy market. This allows these facilities to be active participants in the energy market and potentially ESS that can meet technical requirements. The operation of the storage facilities in both models is optimised to charge when residual demand is low, and discharge when residual demand is high. These facilities do so based on fixed inputs of future demand. The dispatch of storage is performed to reduce system cost.
Facility bidding	Individual generator units in a power station are modelled explicitly in all WOSP models. These units are assigned to a facility with offers provided on a facility basis. Wind farms and solar farms are represented by a single facility representing the aggregate capacity of all installed wind turbines and photovoltaic panels. Offers are also provided on a facility basis. Portfolio bidding is not used for WOSP market models and it is assumed that Synergy units offer their capacity on an individual short run marginal cost basis.
Fast start inflexibility profiles	Fast start inflexibility profiles are not modelled in the WOSP. Resources modelling is conducted at an hourly time-step whereas dispatch modelling is modelled at a half-hourly time step. Therefore, constraints on fast start capability are not expected to bind and are considered immaterial to the WOSP.
Gate closure	The methodology employed for the WOSP does not propose to implement dynamic rebidding. As such, gate closure is not an explicit consideration.
Generators less than 10 MW	The WOSP models all generators that are Registered Facilities. The market models do not make a distinction between a generator less than 10 MW and a generator greater than 10 MW for the purpose of energy scheduling and dispatch.
Intermittent generation offers	The market models used in the WOSP allow intermittent generators to offer multiple price-quantity pairs into the energy market. The price offered can be non-zero and intermittent generators are not constrained to being price-takers. However, for the WOSP, all intermittent generators offer their expected (and available) generation output into the market at a single price. The offer price is defined as an input assumption.
Intermittent loads	Intermittent loads that appear in constraint equation formulations are modelled explicitly with an assumed half-hourly load profile. This allows the WOSP market models to consider their impact on the evaluation of constraint equations.
Mandatory offer obligations	All facilities that hold Capacity Credits are required to offer at least that much capacity into the energy market.

Element	Treatment in the WOSP
Ramp rates	Ramp rate limitations are taken into account from one trading interval to the next trading interval when dispatching generation in WOSP market models.
Regional Reference Node (RRN)	The RRN is assumed to move to Southern Terminal for the entire 20-year study period, despite being proposed to be implemented in 2022. All marginal loss factors for existing facilities and the formulation of constraint equations are based on Southern Terminal being the RRN.
Security constrained economic dispatch (SCED)	Constraint equations have been formulated for modelling purposes based on the implementation of a fully constrained network access arrangement. Generators are dispatched to minimise system costs in each time-step resolution subject to constraints. SCED is modelled in the WOSP for the 20-year study period.

3.5.2 The Reserve Capacity Mechanism

The market dispatch model includes a capacity model based on the WEM's RCM.

AEMO sets the Reserve Capacity Target (RCT) annually for the WEM. The RCT is AEMO's estimate of the total amount of generation and DSP capacity required in the SWIS to satisfy part (a) (annual expected 10% Probability of Exceedance (POE) peak demand forecast) and part (b) (annual expected unserved energy) of the Planning Criterion[8] for a Capacity Year. The calculation of the RCT takes into account the annual 10% POE forecast, a reserve margin, Frequency Regulation requirements and an intermittent load allowance.

The RCT sets the number of Capacity Credits to be procured in each capacity year and is an input into the Reserve Capacity Price calculation which is based on administered pricing formulas. The parameters in these formulas have been modified as part of recent reforms[9].

As part of the WOSP, an estimate of the RCT is developed based on the 10% POE peak demand forecast provided in each of the four scenarios. A Frequency Regulation requirement and intermittent load allowance is assumed for each scenario. The Frequency Regulation requirement is based on the outcomes of the intermittent generation build in the resources model and the assumption around the uptake of DER for that scenario.

Allocation of Capacity Credits

The generation supply outcomes of the resource planning model and any capacity mix modifications made as part of the dispatch modelling have been used to determine the number of Capacity Credits to be allocated in each scenario. However, given the proposed introduction of a constrained network access model in the SWIS by 2022, the allocation of Capacity Credits to each facility remains subject to review.

The Taskforce is proposing changes to the way Capacity Credits are allocated under the RCM, through the introduction of Network Access Quantities. This approach will directly impact the amount

[8] The Planning Criterion is outlined in clause 4.5.9 of the WEM Rules

[9] https://www.wa.gov.au/government/document-collections/improving-reserve-capacity-pricing-signals

of Capacity Credits available to new facilities and will provide signals that are likely to impact the type and location of generation in the SWIS.

At time of undertaking the WOSP modelling, the high-level design of the Capacity Credit allocation method remained under development[10] and is therefore not incorporated in the inaugural WOSP.

3.5.3 Testing commercial viability

To assess the commercial viability of new entrant generation and storage facilities, the annual net revenue of each facility has been calculated as outlined below;

Annual new entrant generator revenue is calculated for the relevant years using the following equation:

> *Net revenue = energy market revenue + ESS revenue/costs + capacity payment – O&M costs – ESS costs – fuel costs*

Where:

- *Energy market revenue* is the total annual wholesale market revenue earned over each trading interval in the year. This is the sum-product of the modelled dispatched generation and the wholesale market price over all trading intervals, multiplied by the facility's loss factor;
- *ESS revenue* is the annual co-optimised ESS revenue earned by the relevant facility over each trading interval in the year;
- *capacity payment* is the total annual capacity payment earned over the year. This is modelled as the amount of Capacity Credits allocated to a particular facility multiplied by the Reserve Capacity Price;
- *Operation and Maintenance* (O&M) *costs* is the total fixed and variable operation and maintenance costs;
- *ESS costs* is the annualised costs incurred by facilities that contribute to the ESS requirement; and
- *fuel costs* is the total cost of the fuel used by a generator to produce electrical energy throughout the year.

The annual cash flow has then been used with the upfront capital cost to calculate an ungeared Internal Rate of Return (IRR) to allow for an assessment of commercial viability of the generation or storage investment.

[10] Design elements that require further development include the conditions under which a facility's Capacity Credit allocation will be reduced, or can be transferred between market participants; and the treatment of storage, embedded generation, and demand response under the proposed arrangements. EPWA released an information paper, *Assigning Capacity Credits in a Constrained Network* on 20 February 2020.

4. Modelling deliverables

The WOSP is designed to provide a view on the transmission network, generation and storage investments that may be required to meet future demand and system security requirements under the four scenarios: *Groundhog Day, Cast Away, Techtopia,* and *Double Bubble*. The WOSP and the modelling that underpins it has not been designed to present a perfect view of the future, rather it is intended to be used to inform future infrastructure investment requirements by identifying 'priority' or 'least-regrets' investments, regulatory decisions, and policy and market development initiatives.

Table 4.1 presents the modelling outcomes that will reported for each of the scenarios across the 20-year study period.

Table 4.1: Modelling outcomes to be reported for each scenario

Modelling outcome	Reporting basis	Unit
System costs		
Total capital expenditure (transmission network, generation and storage)	Annual	$million
Fuel supply costs	Annual	$million
Fixed and variable operating and maintenance costs	Annual	$million
Cost of unserved energy	Annual	$million
Cost of ESS	Annual	$million
Generation outcomes		
Generation achieved	Annual, for each facility	GWh
Generation and storage capacity additions and closures by supply technology	Annual, for each node	MW or GW MWh or GWh
Transmission network		
Transmission network build	Annual	MW, project basis
Emissions		
Annual emissions attributed to the WEM	Annual	MT CO_2-e

To test that the information provided by the WOSP is robust and meaningful, sensitivity analysis has been conducted on the modelling outputs.