Energy Transformation Taskforce

Whole of System Plan modelling methodology and assumptions

Information paper

Prepared by the Energy Transformation Implementation Unit

29 November 2019

An appropriate citation for this paper is: Whole of System Plan modelling methodology and assumptions

Energy Transformation Taskforce

David Malcolm Justice Centre
28 Barrack Street
Perth WA 6000
Locked Bag 11 Cloisters Square WA 6850

Main Switchboard: 08 6551 4600

www.energy.wa.gov.au

Enquiries about this report should be directed to:

Miles Jupp

Email: miles.jupp@energy.wa.gov.au

Disclaimer

The information, representations and statements contained in this information paper 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 approach discussed in this information paper may be modified during the project. The proposed modelling scenarios do not necessarily reflect government policy.

Any views expressed in this information paper are not necessarily the views of the State of Western Australia, the Western Australian Government (including the Minister for Energy), or the Energy Transformation Taskforce, nor do they reflect any interim, firm or final position adopted by the Government in connection with the Whole of System Plan.

The State of Western Australia, the Minister for Energy, the Energy Transformation Taskforce, Energy Policy WA, and their respective officers, employees and agents:

- make no representation or warranty as to the accuracy, reliability, completeness or currency of the information, representations or statements in this publication (including, but not limited to, information which has been provided by third parties); and
- shall not be liable, in negligence or otherwise, to any person for any loss, liability or damage arising out of any act or failure to act by any person in using or relying on any information, representation or statement contained in this publication.

Contents

Abbreviations v
Summary 1

WOSP modelling methodology

1. Background and context 5
1.1 Interaction with other elements of the Energy Transformation Strategy 5
1.2 Stakeholder engagement 6
2. Inputs and assumptions 7
2.1 Customer demand 7
2.2 Network augmentation 9
2.3 Generator costs 9
2.4 Essential system services 10
2.5 Other modelling considerations 11
2.5.1 The Energy Transformation Strategy 11
2.5.2 The Reserve Capacity Mechanism 13
2.5.3 Testing commercial viability 14
3. Modelling methodology 15
3.1 Resource planning model 16
3.2 Dispatch model 18
4. Modelling deliverables 20
5. Next steps 22
Appendix A Data and Assumptions Workbook A-1

List of tables

Table 2.1: Summary of key Energy Transformation Strategy design elements and their treatment in the inaugural WOSP 11
Table 4.1: Modelling outcomes to be reported for each scenario 20

List of figures

Figure 1.1: Next steps 3
Figure 2.1: Key modelling inputs and assumptions 7
Figure 2.2: Map of key transmission generation constraints 8
Figure 2.3: SWIS nodal resolution 9
Figure 3.1: The WOSP modelling process 16
Figure 3.2: Overview of the network and generation resource planning model 18
Figure 3.3: Overview of the dispatch model 19
Figure 5.1: Next steps 22

Abbreviations

The following table provides a list of abbreviations and acronyms used throughout this document. Defined terms are identified in this document by capitals.

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 Network and Generation 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

Summary

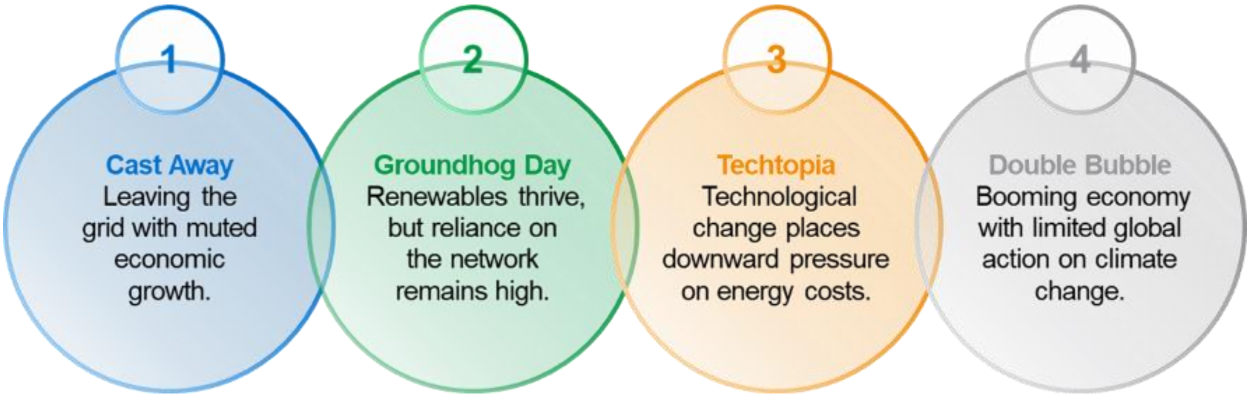
Project overview

The inaugural Whole of System Plan (WOSP) for the South West Interconnected System (SWIS) will be completed in mid-2020. The WOSP will bring together all the important aspects of power system planning under a single umbrella; providing a high-level picture of how the electricity system will develop over the period 2020-2040 (i.e. 20 years).

This work is led by the Energy Transformation Taskforce (Taskforce), in close collaboration with Western Power and the Australian Energy Market Operator (AEMO), who are currently responsible for determining network development and generation needs in the SWIS respectively.

WOSP scenarios

This paper provides an overview of the methodology and input assumptions that will be used to model the four WOSP scenarios: *Cast Away, Groundhog Day, Techtopia, and Double Bubble.*



For each scenario, the WOSP will present a view on the generation capacity mix and network investment required to meet demand at the lowest sustainable system cost. The WOSP modelling data can then be used to inform future investment plans and energy policy decisions.

Modelling

Two key models are being used:

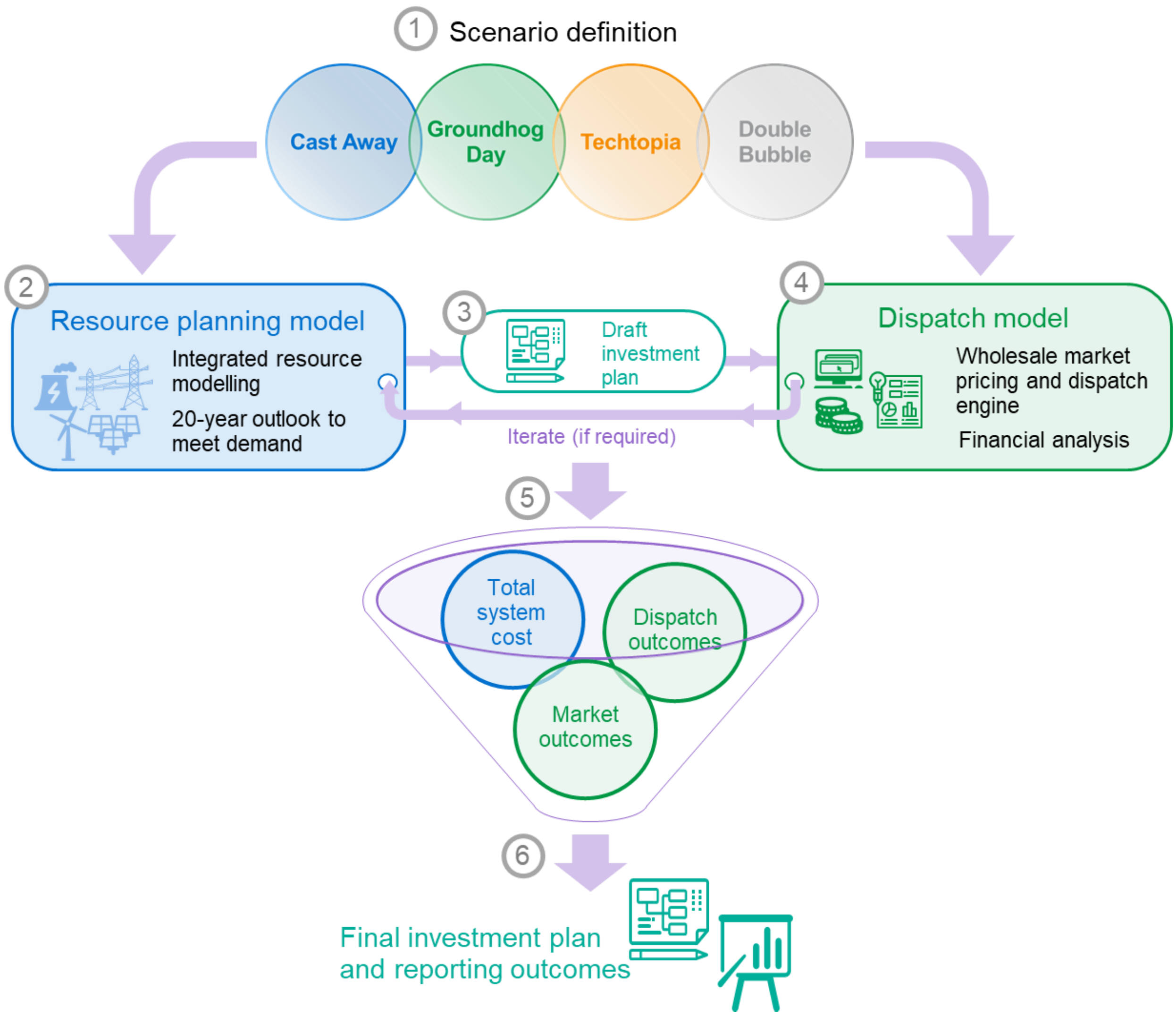
- a network and generation resources planning model (resource planning model); and
- a market dispatch model (dispatch model).

The resource planning model is used to calculate total system costs[1] and produce outputs that can be used to inform the optimal generation and network investment plan necessary to sustain the power system under each modelling scenario.

The dispatch model then uses the outputs of the resource planning model to simulate outcomes in the Wholesale Electricity Market (WEM) if the proposed generation and network investment plan was to be implemented. The following diagram illustrates the way the two models interact.

---

[1] Total system costs relate to the cost of network, generation and storage infrastructure and comprise capital expenditure, total fixed costs, total variable costs, retirement costs, total fuel costs, and unserved energy.



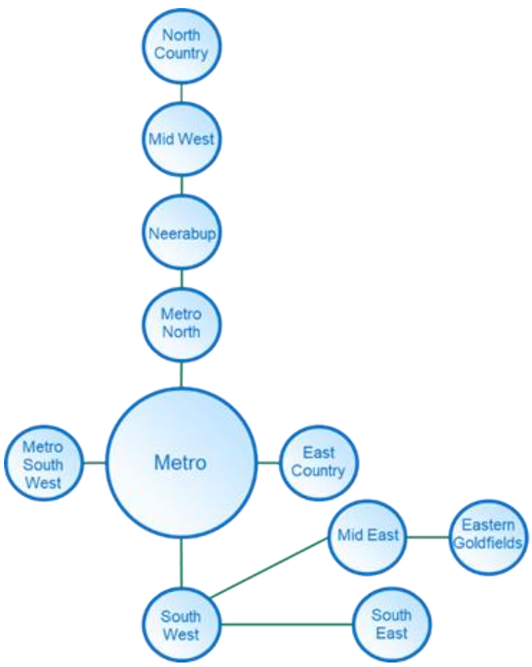
Together, the two models will produce an indicative outlook of what constraints may occur, what challenge/opportunities may arise, and what investments would be required under each modelling scenario. The modelling outcomes will be tested for technical feasibility, to ensure any proposed investments are capable of being implemented from an operational standpoint.

Modelling outputs will be shared with market participants and can be used to inform the future development of, and investment in, the SWIS by market participants, Western Power and AEMO.

Modelling inputs and outputs

Modelling inputs include demand and supply side assumptions, cost drivers, investment/retirement plans and fixed/variable costs. The SWIS will be modelled using eleven nodes that represent the transmission network.

Nodes and interconnector boundaries are based on the location of existing and future customer demand points, generation facilities, and transmission network constraint. This nodal approach will add granularity to the modelling and improve the quality of outputs.



Inputs have been developed by the Energy Transformation Implementation Unit (ETIU), in partnership with Western Power and AEMO, and informed and tested via consultation with more than 20 industry participants and stakeholders.

Western Power has provided network augmentation costs for increasing transfer limits between nodes, and generation assumptions have been tested with WEM participants and other stakeholders and refined accordingly. AEMO has led development of the modelling assumptions and approach to reflect the new Essential System Services (ESS) framework in the WOSP.

Every effort will be taken to ensure inputs reflect the key market design elements being developed across the three Energy Transformation Strategy workstreams.

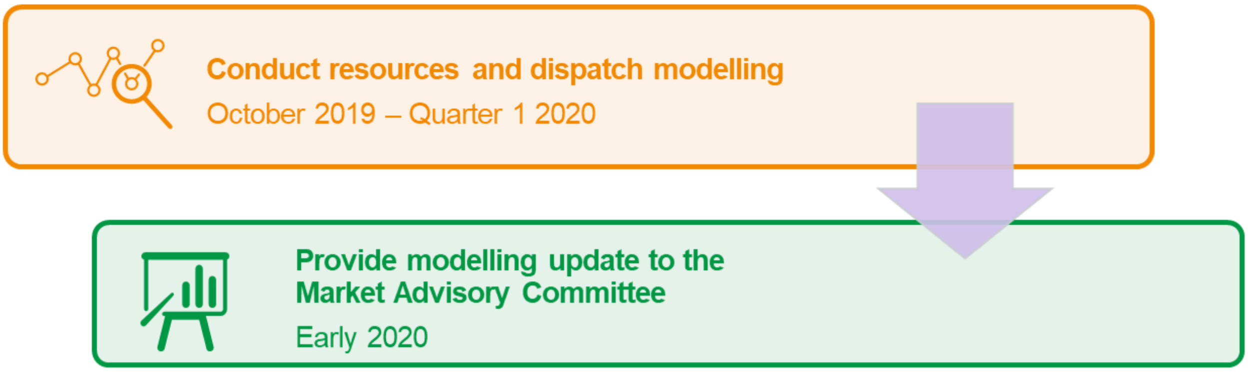
Modelling outputs will be indicative only. The intention is not to predict the most likely future, rather, the purpose of the WOSP is to prepare a reasonable and well-informed view of what investment and technology is likely to be required under the four modelling scenarios. The WOSP output data can then be used to inform the investments and policy decisions in the SWIS, for the long term benefit of Western Australian electricity consumers.

Modelling outcomes will be shared and tested with Market Participants prior to the finalisation of the WOSP. Any sensitive or confidential information collected during development of the modelling inputs will not be published and will only be retained for modelling purposes.

Next steps

Modelling work has commenced and will continue over the coming months. ETIU will provide a modelling update to the Market Advisory Committee in early 2020.

Figure 1.1: Next steps



WOSP modelling methodology

1. Background and context

Currently, there is no single entity responsible for planning the power system that delivers electricity to households and businesses in the south west of the state. AEMO forecasts generation needs, while Western Power is responsible for planning the development of its network.

This system has served customers well enough in the past. However, managing the power system through the transition to renewable and distributed electricity sources requires stronger coordination to provide clear information for investors and planners, and to guide the development of the power system of the future.

In response to these challenges, the Government is developing a whole of system plan, bringing together the important aspects of power system planning under a single umbrella.

The WOSP is a detailed study into the current state and the future of the SWIS. The plan has a 20 year outlook and will present a view on the generation and network investments that may be required to meet future demand. 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, smaller-scale, distributed, lower emissions technologies.

In simple terms, the purpose of the WOSP is to inform decisions about managing and investing in Western Australia's principal power system. Over time, as more data is gathered and each iteration of the WOSP increases in maturity, the WOSP may include scenarios that more narrowly define the direction the SWIS is heading. However, in the short term, the real value of the WOSP is the modelling outputs it produces and the decisions that can be made using it.

Delivering the inaugural WOSP by mid-2020 is one component of the Western Australian Government's Energy Transformation Strategy. The three workstreams are:

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

More information on the WOSP and other the Energy Transformation Strategy workstreams can be found on the Energy Policy WA website.[2]

1.1 Interaction with other elements of the Energy Transformation Strategy

The Energy Transformation Strategy will see the implementation of a range of reforms to the design of the WEM. These reforms will impact the way facilities are scheduled and dispatched, and have implications for the way modelling is conducted for the WOSP. Where possible and practical to do so, the modelling will use consistent inputs across the three Energy Transformation Strategy workstreams and incorporate key market design elements when they become available.

The Foundation Regulatory Frameworks and DER workstreams are being run in parallel with Whole of System Planning. It is therefore likely some design elements or parameters being developed under the other workstreams will not be finalised when the WOSP modelling is undertaken.

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

For this inaugural WOSP, it is proposed to only include inputs/decisions from other workstreams that have been endorsed and published by the Taskforce at the time of undertaking the modelling, and that are material to the modelling being undertaken. The Taskforce's most recent publications can be found on the Energy Policy WA website: https://www.wa.gov.au/government/document-collections/taskforce-publications

The initial runs of the WOSP models will be conducted over the course of Q4 2019 to Q1 2020. All inputs, assumptions and new information available during the course of undertaking the modelling will be reviewed, and the modelling method updated where practicable to ensure the WOSP produces the most meaningful data available in the circumstances.

For example, the operation of the Reserve Capacity Mechanism (RCM) and the allocation of capacity credits will be an important WOSP modelling input. Preliminary design work on a revised RCM has commenced[3], and the ETIU will consider the best way to incorporate this work into the modelling approach as more detail becomes available.

Any variations to the modelling approach outlined in this paper, as well as any sensitivity analysis undertaken, will be captured and communicated to stakeholders when the modelling results are finalised. Market design elements and Energy Transformation Strategy deliverables that are not available prior to finalising the inaugural WOSP modelling, will be incorporated in future editions of the WOSP.

Section 2.5.1 of this paper provides a summary of the key design elements considered in the Energy Transformation Strategy and how they will be treated in the inaugural WOSP.

1.2 Stakeholder engagement

The WOSP modelling inputs have been developed and tested via more than 70 meetings with over 20 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 will help improve the quality of the WOSP modelling inputs and therefore the robustness of modelling outputs. The Taskforce appreciates the support provided by stakeholders to date and highlights that sensitive information provided by third parties will remain strictly confidential.

Stakeholders have generally supported the engagement approach to date. There is broad acceptance that the modelling will be based on reliable data, and that the outputs will provide meaningful information.

This collaborative approach will continue throughout the WOSP development. Modelling work has already commenced and will continue over the coming months. The ETIU aims to provide a modelling update to the Market Advisory Committee in early 2020.

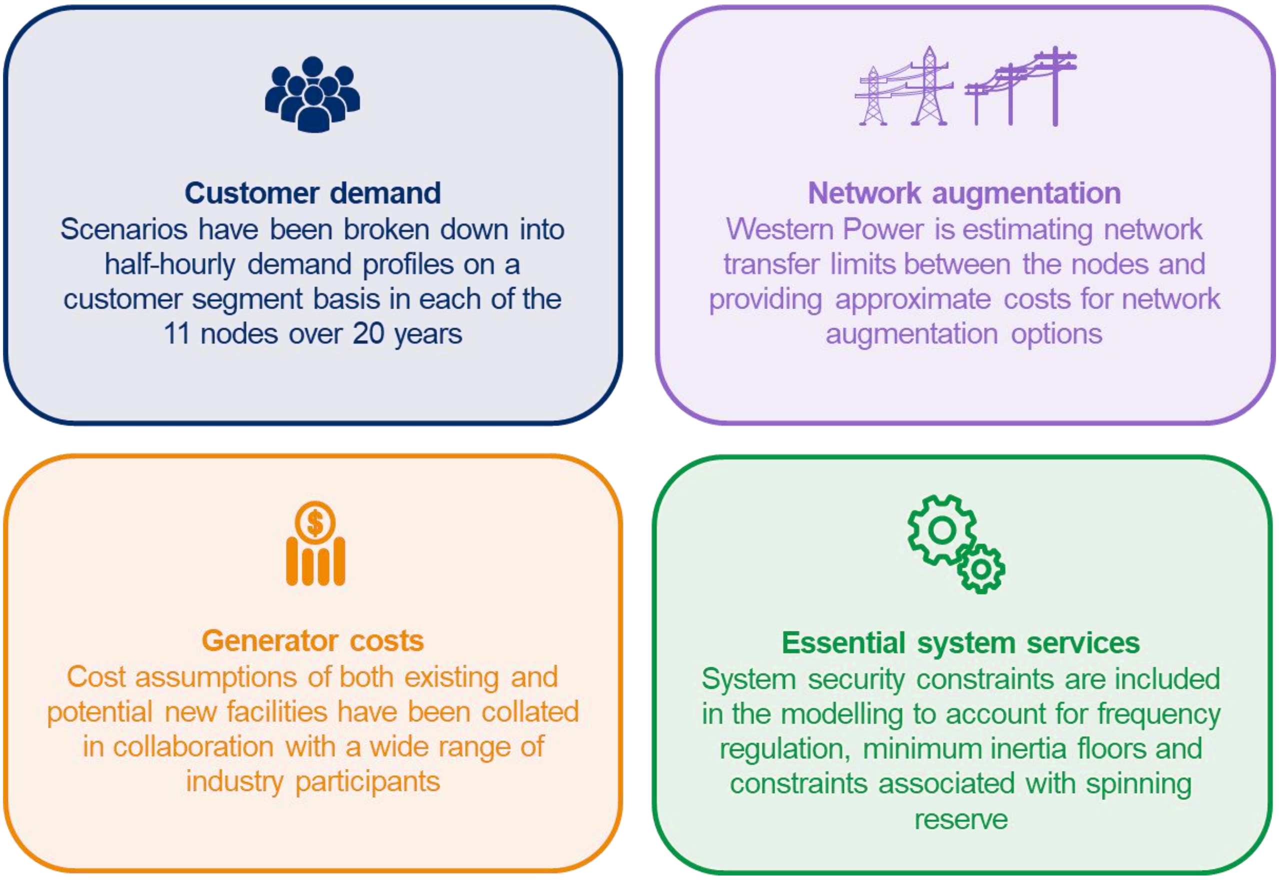
[3] https://www.wa.gov.au/sites/default/files/2019-10/Allocation%20of%20Capacity%20Credits%20in%20a%20constrained%20network%20-%20Design%20Proposal.pdf

2. Inputs and assumptions

The Project Team (comprising the ETIU, Western Power and AEMO representatives) has developed demand and supply side inputs and assumptions that will inform 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 network nodes.
- **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 2.1: Key modelling inputs and assumptions



A Data and Assumptions Workbook is provided with this paper at Appendix A. The workbook provides an overview of inputs and assumptions, using publicly available data. Confidential and/or sensitive information provided by market participants will not be published.

2.1 Customer demand

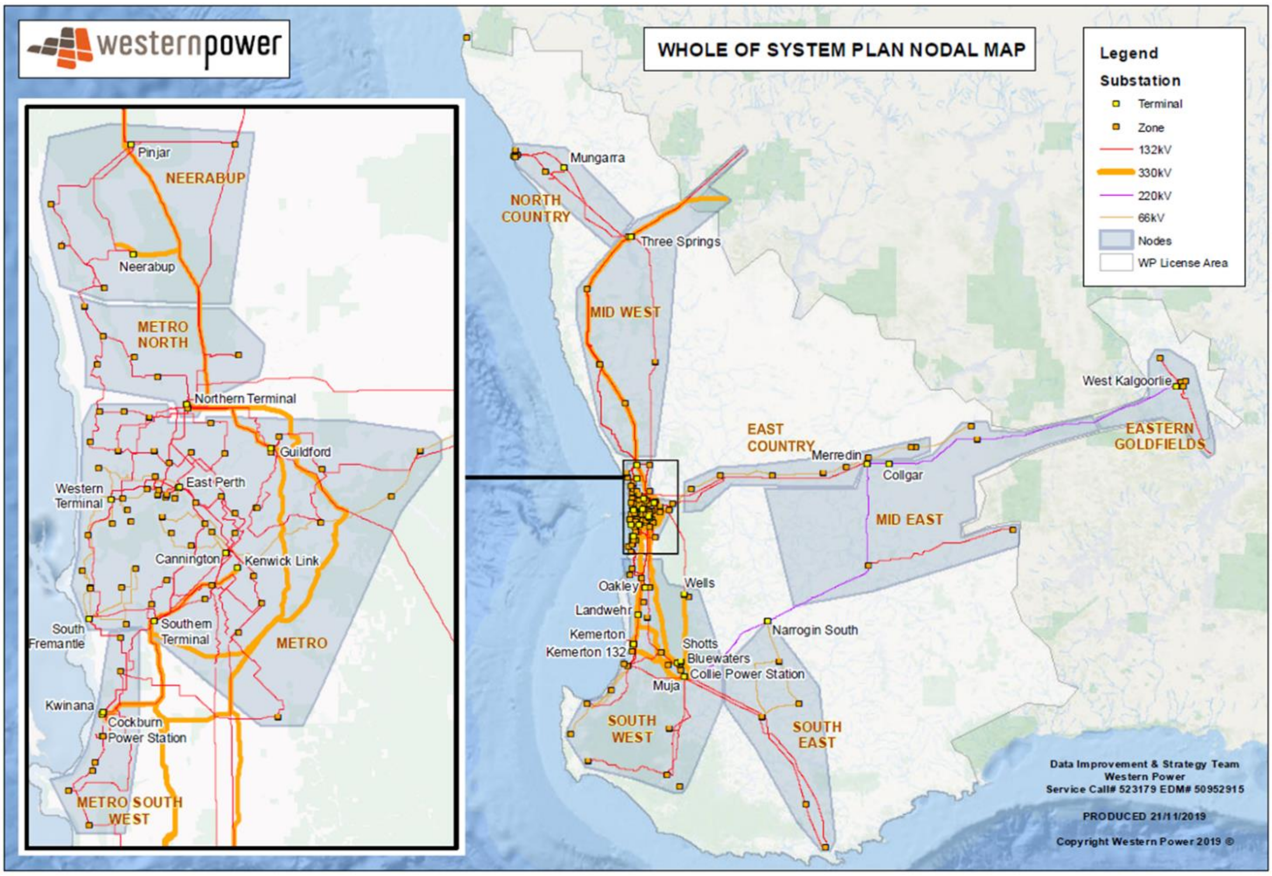
For each scenario the Project Team has modelled an estimate of demand for the next 20 years. To provide a reasonable and robust estimate, the following steps have been taken:

1. separated the SWIS into 11 nodes, based on Western Power's planning areas and view of existing and likely network transfer boundary limits (as shown in Figure 2.2);

2. allocated customer demand to a substation or a point load[4]. This encompasses 108 substations and 600 point loads;
3. allocated substations/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;
5. adjusted demand within each node for the impact of DER, mostly solar photovoltaic systems, and wind generation. The DER and wind generation adjustments are based on nine years of weather data, including solar irradiance and wind patterns; and
6. factored other forms of DER such as battery storage and electric vehicles into the demand forecasts, as well as additional block 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[5], a range of economic, demographic and technological drivers and data sources have been used to inform the demand estimates.

Figure 2.2: Map of key transmission generation constraints



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

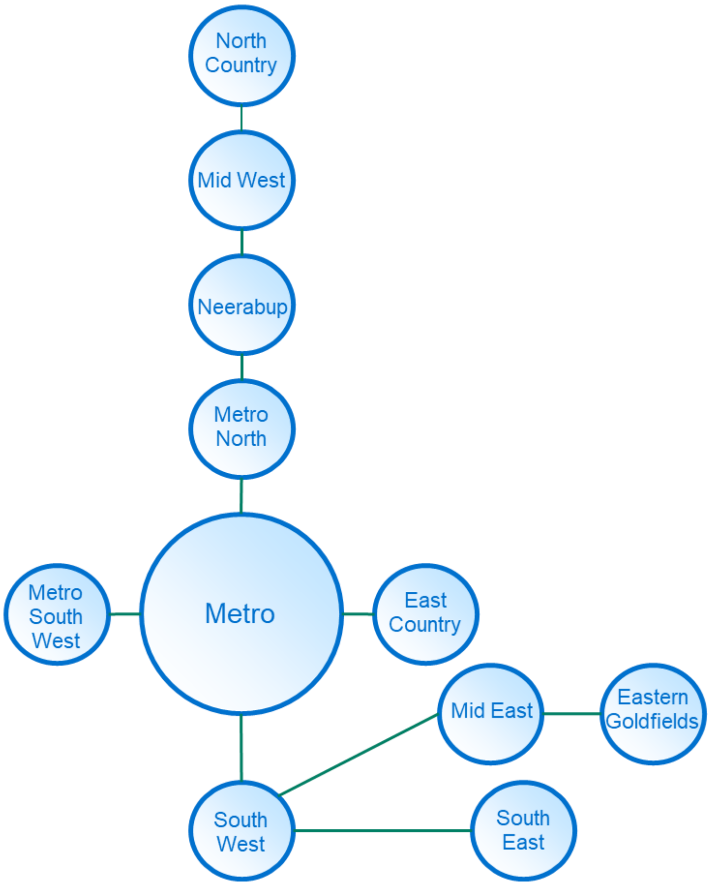
[5] https://www.wa.gov.au/sites/default/files/2019-08/Whole-of-System-Plan-Industry-Forum-Presentation-12-July-2019.pdf

2.2 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 nodes. The 11 nodes are shown in Figure 2.3.

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

Figure 2.3: SWIS nodal resolution



2.3 Generator costs

The current and forecast costs of generators currently connected and expected to connect to the SWIS are an important input into the WOSP. The ongoing cost of different generation types will be vital in providing meaningful data on which to inform future investment decisions in the SWIS.

The ETIU has therefore conducted a series of one-on-one meetings with generators and investors, to test a range of generation assumptions. For existing plant, assumptions tested with each owner include where the generator is on the nodal map, what type of fuel it uses, ramp rates, cold start costs, heat rates, fixed operating costs, and variable operating costs. Stakeholders have generally supported the fuel price outlooks and provided refined information on the operational costs for existing facilities.

The ETIU has also engaged with a number of infrastructure investors, who have shared their views on the returns on investment being experienced, risk appetite and access to funding. This information is consistent with the assumptions in the National Electricity Market Integrated System Plan[6] (NEM ISP) and will be 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 ETIU following publication of the WOSP.

Where appropriate the WOSP will use NEM ISP assumptions for new plant. The types of new plant considered in the generation assumptions are:

- closed cycle gas turbine;
- open cycle gas turbine;
- solar PV;

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

- storage (battery, hydro and compressed air); and
- wind.

For detailed information on modelling inputs, refer to the Data and Assumptions Workbook provided with this paper at Appendix A.

2.4 Essential system services

As the generation capacity mix in the WEM 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 must therefore include consideration of how ESS requirements impact total system costs, generation dispatch and the required generation capacity mix over the 20-year study period.

The costs of providing ESS will be calculated as the difference between the costs of scenarios with and without ESS provision. The difference in total system costs across the two cases is representative of the costs required to be recovered in the ESS market. Different dispatch outcomes and the potential impact on the required generation capacity mix over the study period will be identified.

The following ESS will be modelled in the WOSP:

- frequency regulation;
- frequency contingency down; and
- frequency contingency up (which takes into consideration primary frequency response (PFR) and rate of change of frequency (RoCoF)).

The modelling approach will be broadly aligned with the ESS frameworks proposed in the Delivering the Future Power System[7] 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 regulation requirement in each of the scenarios will be 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 photovoltaic systems and utility-scale wind and solar farms will lead to increased volatility in system frequency and, consequently, higher frequency regulation requirements.

- **Frequency contingency down** – the dispatch of the frequency contingency down service (or load rejection reserve) in the SWIS will be assumed to remain similar to the current practice in the WEM for all scenarios. The frequency contingency down service is dispatched to meet a requirement defined in MW, that is set as a function of system load.

- **Frequency contingency up** – the WOSP dispatch model will implement dispatch constraints to ensure generators are available to provide PFR in the event of a sudden loss of supply. The WOSP modelling for frequency contingency up will depart from the current practice in the WEM for provisioning spinning reserve. The intent is to align modelling with the new ESS framework that results from the detailed work to implement the new market arrangements. The proposed ESS

[7] Part of the Foundation Regulatory Frameworks workstream.

framework acknowledges the crucial role of system inertia and speed of response of PFR providers in maintaining system security.

2.5 Other modelling considerations

2.5.1 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 the forthcoming WOSP, key design elements will be incorporated in the modelling where practicable.

Table 2.1 presents an overview of the proposed treatment of key market design elements in the inaugural WOSP.

Table 2.1: Summary of key Energy Transformation Strategy design elements and their treatment in the inaugural WOSP

Element	**Treatment in the WOSP**
Aggregated DER	It is likely that aggregated DER will emerge as an option during the WOSP planning horizon. Where possible the effect of aggregated DER will be considered as one of the options on the supply side in the modelling.
Co-optimisation of energy and ESS	Where dispatch constraints are being modelled to represent the impact that ESS markets may have on generator dispatch, these constraints will be formulated on a linear basis and form part of the WOSP modelling constraint set that includes transmission network, system and ESS constraints. These constraints will be solved simultaneously. The specific co-optimisation of energy and ESS markets will not be modelled.
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. 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 for 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.

Element	Treatment in the WOSP
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.
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.

Element	Treatment in the WOSP
	Generators are dispatched to minimise system costs in each time-step resolution subject to constraints. SCED is modelled in the WOSP for the 2--year study period.

2.5.2 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 in 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 will be developed based on the 10% POE peak demand forecast provided in each of the four scenarios. A frequency regulation requirement and intermittent load allowance will be assumed for each scenario. The frequency regulation requirement will be 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 will be 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.

A Design Proposal paper[10] was recently presented to the Taskforce that proposes changes to the way capacity credits are allocated under the RCM. These changes, if adopted, will directly impact the amount 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 writing this paper, the high-level design of the capacity credit allocation method remains under development[11]. To the extent possible, WOSP modelling will be updated to reflect the capacity credit allocation method when finalised.

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

10 https://www.wa.gov.au/sites/default/files/2019-10/Allocation%20of%20Capacity%20Credits%20in%20a%20constrained%20network%20-%20Design%20Proposal.pdf

11 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.

For completeness, the actual modelling approach adopted with regard to the RCM, and any other variations from the modelling methodology outlined in this paper, will be documented and shared with stakeholders when the WOSP modelling results are presented in mid-2020.

2.5.3 Testing commercial viability

To assess the commercial viability of the new entrant generation capacity investment plan, the annual net revenue of each facility is calculated using pricing outcomes from the WEM including the RCM.

New entrant generator revenue is then calculated for any particular year using the following equation:

> *Net revenue = pool revenue + capacity payment + other revenue – O&M costs – capital cost repayment – fuel costs*

Where:

- *pool 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;
- *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;
- *other revenue* and/or costs that may be associated with provision of ESS, and the renewable energy target;
- *Operation and Maintenance* (O&M) *costs* is the total fixed and variable operation and maintenance costs
- *capital cost repayments* is the annualised capital cost of the generator, taking into account the assumed economic life and weighted average cost of capital for the study; and
- *fuel costs* is the total cost of the fuel used in the generator's modelled production of electrical energy throughout the year.

3. Modelling methodology

The WOSP will be developed using the outputs from two key models:

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

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

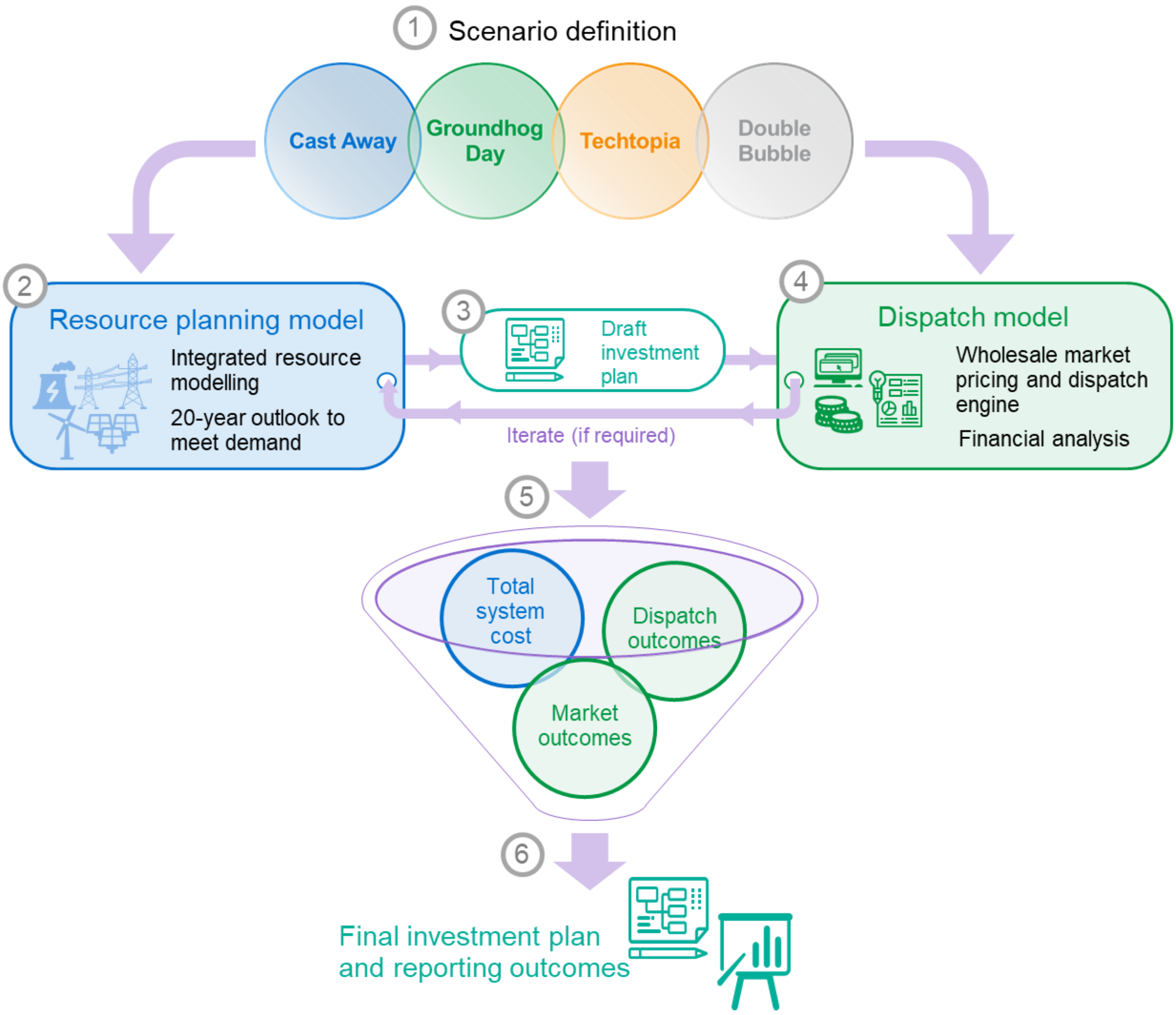
The dispatch model will then simulate the market outcomes in the WEM if the network and generation investment plan produced by the resource planning model was to be implemented. Together, these two models will produce an indicative outlook of what power system and transmission network constraints may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

It is possible the initial investment plan produced by the resource planning model will recommend generation investments that the dispatch model subsequently determines 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). It is therefore likely that iterations between the two models will be 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 may be used to verify the technical plausibility of the network investment plan. If the transmission network augmentation does not perform as intended, further iterations of the resource planning model may be required, with additional scope items added to the network augmentation options.

The final modelling outputs will be shared with market participants and can be used to inform the investment decisions and government policy that will define the future development of the SWIS. Figure 3.1 provides an overview of the two models and how they interact.

Figure 3.1: The WOSP modelling process



3.1 Resource planning model

The resource planning model is used to identify the lowest sustainable cost of new generation and transmission infrastructure required to meet demand, reliability requirements and technical standards in each modelling scenario. The model is used to identify how to minimise total system costs 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 generation and network 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, variable and fuel supply) and unserved energy, over the entire 20-year study period. The NPC of generation and network 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 ESS requirements.

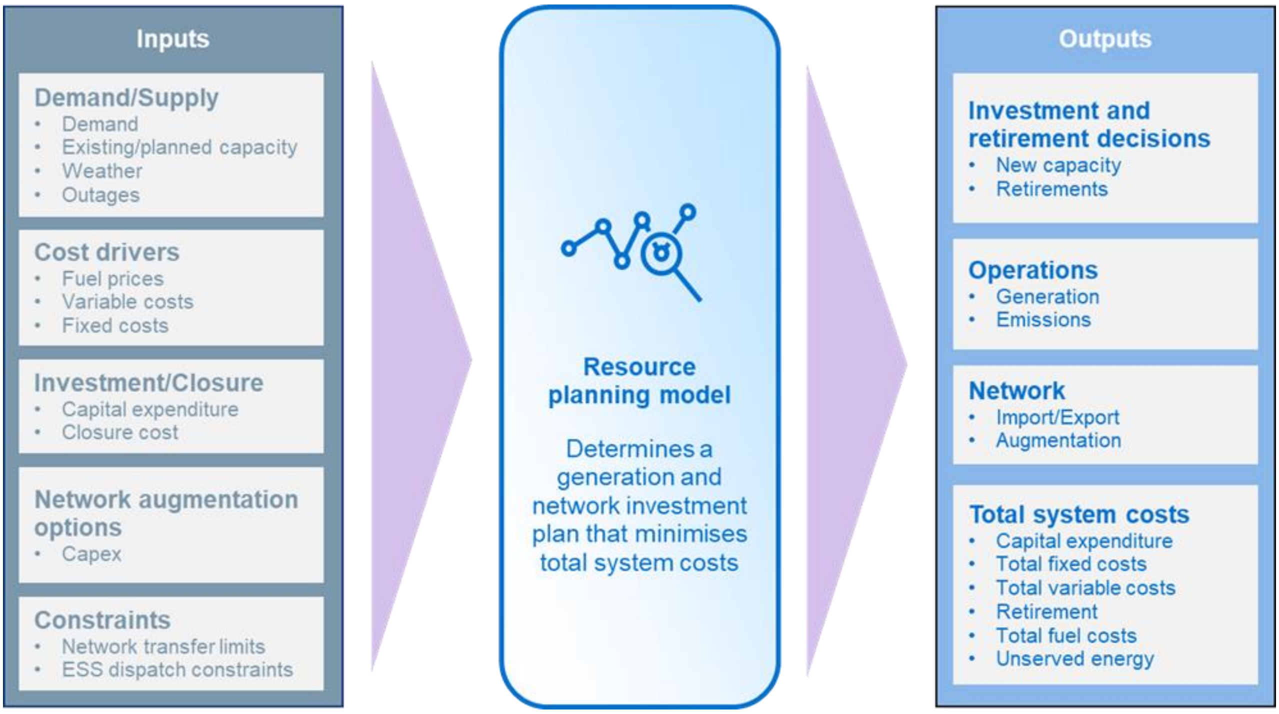
Subject to annual scenario constraints and new entrant build limits, the resource planning model co-optimises transmission network and generation investment to minimise the NPC over the 20-year study period by simultaneously making decisions on:

- commissioning new entrant generation and storage capacity for each defined technology type;
- augmenting the transmission network based on a pre-defined list of network augmentation options 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 3.2 provides an overview of the inputs and outputs of the resource planning model.

Figure 3.2: Overview of the network and generation resource planning model



3.2 Dispatch model

The market dispatch model is used to model 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 and assumes the implementation of security constrained economic dispatch for the entirety of the 20-year study period. Dispatch decisions will be based on the principles of security constrained economic dispatch, considering generator bidding patterns and availabilities to meet regional demand 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.

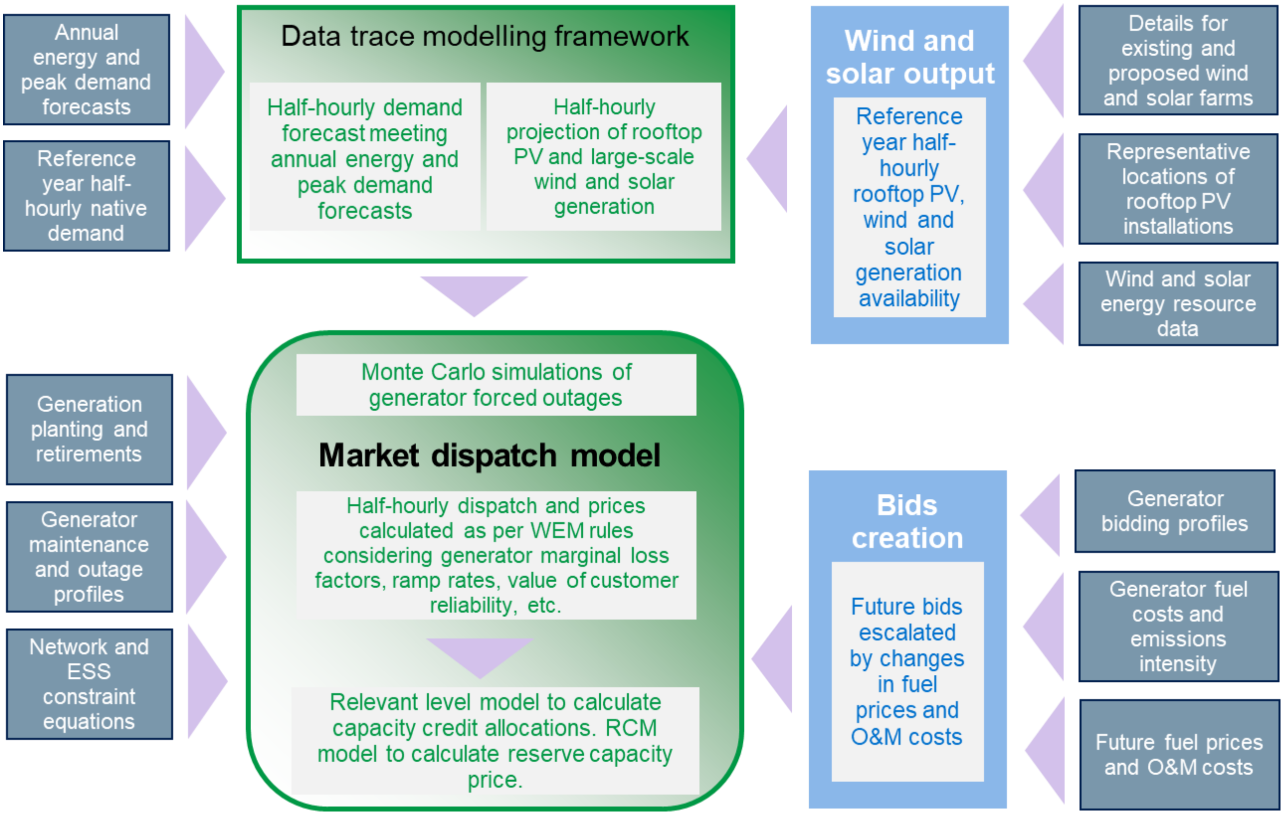
The same ESS dispatch constraints that are modelled within the resource planning model (i.e. representing frequency regulation, frequency contingency down and frequency contingency up) will be used within the dispatch model.

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.

Accordingly, the dispatch model can be used to determine the commercial viability of the market mix produced by the resource planning model's proposed network and generation investment plan under each scenario. If the dispatch model indicates that the investment plan is not feasible, the resource planning model may need to be re-run with additional constraints. A new investment plan would then be tested via the dispatch model.

Figure 3.3 provides a high-level overview of the dispatch model.

Figure 3.3: Overview of the dispatch model



Sensitivities on different modelling inputs will be run, subject to time and computational complexity constraints, to test the effects of parameter variability on the modelling outputs.

4. Modelling deliverables

The WOSP is designed to provide a view on the generation and network 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 is not designed to present a perfect view of the future, rather it is proposed 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 (generation and network)	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
Market outcomes		
Balancing price	Annual peak and off-peak Annual minimum and maximum	$/MWh
Reservice capacity price	Annual	$/MW
Negative price events	Annual	Number
Unserved energy	Annual	MWh or GWh
Generation outcomes		
Generation achieved	Annual, for each facility	GWh
Capacity factor	Annual, for each facility	%
Generation capacity and energy by supply technology, including impact of retirements	Annual, for each node	MW or GW MWh or GWh
Transmission network		
Transmission network build	Annual	MW, project basis
Transmission network congestion	Most binding constraints	% of year binding
Other		
Annual emissions attributed to the WEM	Annual	MT CO_2-e
Gas usage	Annual	TJ

To test that the information provided by the WOSP is robust and meaningful, sensitivity analysis will be conducted (time permitting) on the modelling outputs. Where sensitive analysis is conducted, a limited set of modelling outcomes will be developed depending on the sensitivity explored.

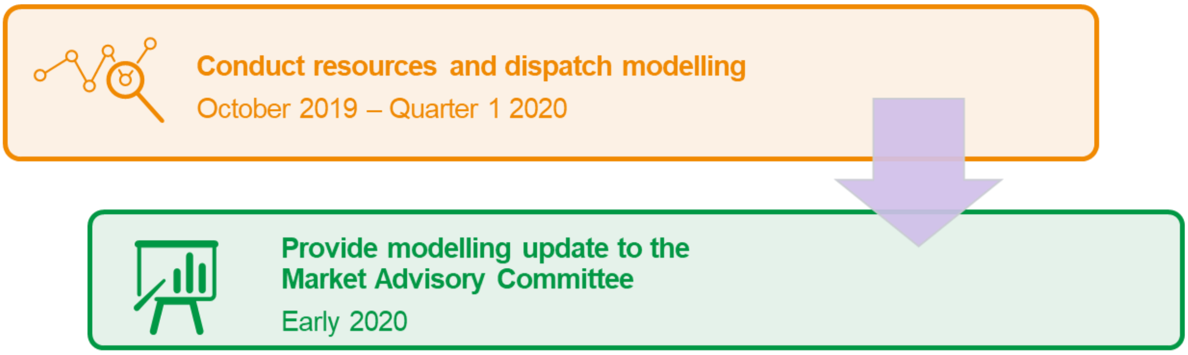
5. Next steps

WOSP modelling will commence in accordance with the methodology outlined in this paper. The ETIU will continue to share progress and exchange information between the other Energy Transformation Strategy workstreams, and will refine and test the modelling approach accordingly.

If you would like to discuss any aspect of the WOSP, please contact us on (08) 6551 2397 or energytransformation@energy.wa.gov.au.

The ETIU will provide a modelling update to the Market Advisory Committee in early 2020, with a public forum to present preliminary findings to be held in mid-2020.

Figure 5.1: Next steps



Appendix A

Data and Assumptions Workbook