MODELLING THE TFTR MODEL

A Report to AEMO

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FINAL

Intelligent Energy Systems

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Executive Summary

As part of AEMO's drive to foster efficient investment in the national electricity market (NEM), AEMO has engaged Intelligent Energy Systems (IES) to assess the potential economic benefits of introducing Transferrable Financial Transmission Rights (TFTR) to the market, which are a form of access rights, to electricity generators.

The IES modelling shows:

- By providing generators rights for settlement at the regional reference node (RRN) they will locate in more appropriate locations. This benefits the market as a whole because efficiently located generators and the corresponding transmission investment will lead to lower overall transmission costs;
- Generator sensitivity to the constraint limits (i.e. the physical limits on network capacity) indicates there may be a considerable value in introducing access rights.

The IES modelling was designed to distinguish between the status quo scenario and a scenario with the TFTR model in place.

The TFTR model was established using a set of assumptions representing the most likely market outlook in terms of electricity load growth and fuel costs, and all legislated environmental schemes.

Transmission constraints were taken from AEMO's 2010 National Transmission Network Development Plan (NTNDP) equations, and potential transmission upgrades options were provided to IES from associated work undertaken by AEMO.

The TFTR model incorporates the impact of selected constraints on locational prices used in settlements by generators, and provides for Constraint Support Contracts (CSC) that provides rights to a component of the resulting residues. Through this mechanism CSC provide access to the regional reference node (RRN) for settlements and thus provides a hedge against locational price movements with respect to the RRN.

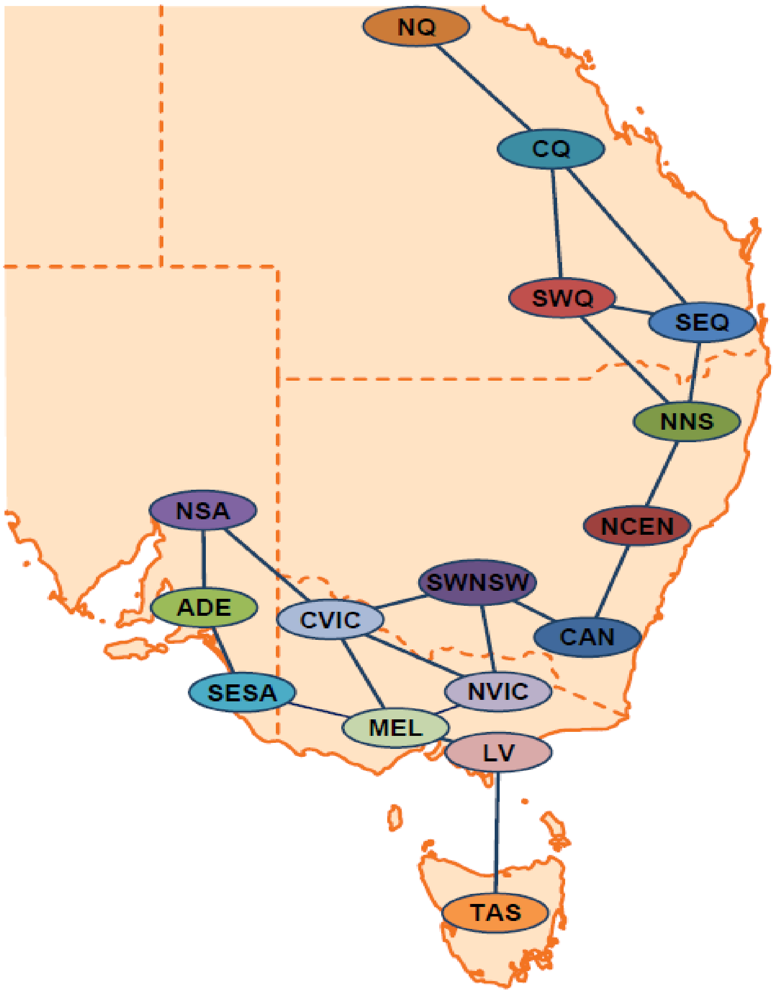
The TFTR model's objectives and features are outlined in the body of the report.

The figure below shows generators do respond to the introduction of a TFTR scheme. This is both in terms of dispatch efficiency and dynamic efficiency. Dynamic efficiency is associated with new generators locating such that the capital requirements of transmission plus generation investment costs are minimised. The TFTR scheme properly prices investment risk which leads to more efficient transmission.

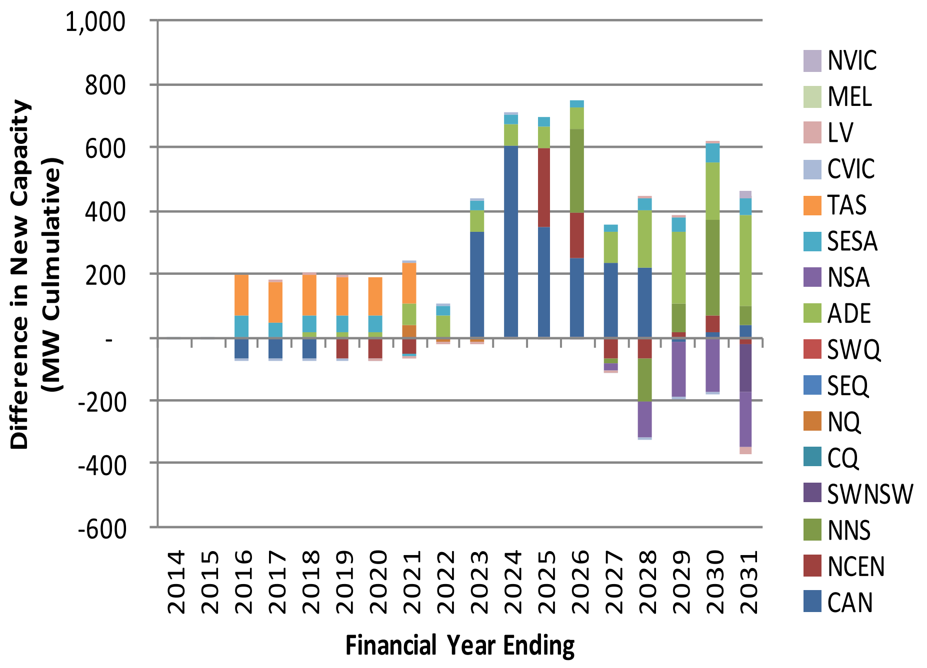
Assumptions in the modeling undertaken for this report resulted in the response to the TFTR being understated due to assumptions of committed transmission, no transmission outage risk, and the high level of wind generation that is insensitive to firm transmission rights.

The figures also show that the TFTR is effective at producing the right investment signals at the right times. The times at which binding constraints escalate – i.e. in 2022/23 and 2028/29 – correspond to a bigger movement of generator location in response. The constraint levels imply a more efficient outcome as generators locate differently as constraint levels rise.

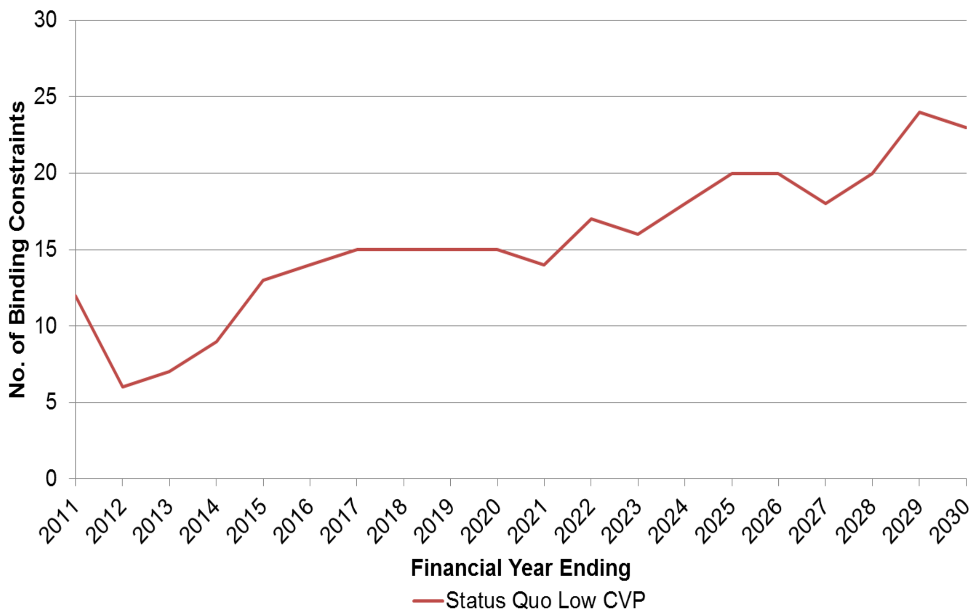
Map of NTNDP zones showing Regional Reference Nodes in each state



Most Likely Scenario – Difference in New Generation Capacity Changes from Status Quo Low CVP to TFTR Cumulative MW



No. of Binding Constraints



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1 Introduction

Location pricing and the impact on dynamic efficiency are issues that have been the subject of many studies since the commencement of the National Electricity Market (NEM). This includes the efficiency gains associated with nodal pricing or its variant constraint support pricing.

As the NEM has developed and new investments in generation have been made and planned, the risks associated with transmission constraints that limit access (to the Regional Reference Node or RRN) have become more apparent.

The impact locational constraint risks are having on the investment outlook in the NEM combined with feedback from the industry on this matter has given rise to AEMO undertaking an investigation of the efficiency gains that could potentially be made through improved location pricing to new generators.

Two models that have been proposed to address location risk issues are the Shared Access Congestion Pricing Model (SACP) and the Commercial Non-firm Access Model (TFTR).

To assist AEMO in quantifying the potential efficiency gains associated with each of these models, AEMO engaged Intelligent Energy Systems (IES) to undertake modelling of the impact the SACP and the TFTR arrangements would have on economic efficiency in the NEM.

Both the SACP and the TFTR arrangements would remove incentives for generators impacted by intraregional transmission constraints to bid “disorderly”. The impact to economic efficiency and settlements was addressed in a separate IES report entitled “Modelling the SACP Model”, which reviewed historical periods where the presence of transmission constraints had resulted generators bidding “disorderly” and presented the results of simulation modelling the SACP arrangements would have to dispatch results and settlements. Economic efficiency changes were confined to changes in fuel costs. (The changed settlement outcomes were based on the SACP allocation methodology.)

The method the SACP model assigns access rights (that does not discriminate between incumbents and new entrants) meant that this model was unlikely to have any impact on new entry locational decisions. Only the TFTR model that assigns access rights on a “first in basis” would have dynamic efficiency benefits.

This report presents the issues, modelling approach and modelling results of the economic efficiency impacts the TFTR model would likely have in the NEM. This is in terms of the changes to generation entry, location of entry and changed transmission development.

1.1 Terms of Reference

The scope of the work is outlined in the document "Valuing Proposed Access Models" prepared by Franc Cavoli and dated 21 November 2011. This document presents the associated arrangements of the SACP and TFTR transmission access models to the extent they were understood and suggests an approach to assessing the associated efficiency benefits of each. This document was supported by a meeting held on the 30 November 2011 between AEMO and IES on the scope and objectives of the study, issues to be addressed and potential approaches. The contents of that document including the description of each of the proposed regimes is not presented here. The description of the access models presented had a number of unresolved issues that were managed through the study.

Using this as a basis of the approach required, the study objectives and deliverables were agreed as follows:

Study Objectives

The objective of the study was to identify and quantify the efficiency gains associated with changed generation and transmission investment (dynamic efficiency) in the TFTR model. In undertaking the modelling, the modelling approach to be used was to be a least cost economic model.

As part of the study, the arrangements associated with the TFTR model regime should be clearly explained and where necessary any associated issues and arrangements clarified.

Deliverables

The deliverables consist of the modelling and analysis outputs, a report and any presentations or discussions as required by AEMO.

1.2 Structure of this Report

The report is structured as follows:

Chapter 2 presents a general description of linear program least cost models. This is done to introduce the concepts used in this study and that are referred to in the approach to the study.

Chapter 3 presents a description of the TFTR arrangements and provides a simple example of its operation. This is presented so the relationship between the TFTR arrangements as proposed and the approach used in the modelling, which does not explicitly represent the TFTR arrangements is understood.

Chapter 4 presents the approach to representing the TFTR arrangements in a least cost model and the issues associated with this representation.

Chapter 5 presents the approach and data used for the representation of the security constraints associated with intraregional transmission. This chapter also presents the transmission upgrades considered and explains issues to how the economics of these in the model compares to that determined by TNSP's via the RIT-T.

With the above explained Chapter 6 reviews the modelling steps undertaken in the study.

Chapter 7 then presents the assumptions used in the cases modelled, the outputs obtained from the modelling and issues of results interpretation.

The modelling results for the two scenarios modelled are then presented in Chapter 8 and 9.

2 Linear Program Least Cost Model

Prior to presenting the approach to modelling the status quo and TFTR models this chapter presents a description of the key elements of a linear program lest cost model and the IES PROPHET model used in this study.

2.1 Overview of Least Cost Models

A linear program least cost model of an electricity system operates to provide the electricity demand at least cost from the available plants and to build additional capacity as required to meet increasing load or to replace plants that are retired. It must also conform to any constraints that are placed on the electricity system such as relating to system operations, planning criteria (generation and transmission), technologies and environmental policies. The model finds a simultaneous solution for all time periods and therefore could be regarded as having "perfect foresight".

Key components of the model are the decision variables, or the outputs to be determined, the constraints on power system operation, and the costs to be minimised.

A key feature of a linear programming least cost model is the ability to co-optimise development across all the annual time sectors and years in the study. Thus transmission development and generation development can be co-optimised, as can be the development of generic (non-renewable) generation and renewable generation under the appropriate incentive schemes.

Brief explanations of the key components are given below. This can be skipped by readers familiar with these models.

2.1.1 Constraints

A number of key constraints are described below.

Transmission Constraints

These were described in Section 5 and express limitations on generator dispatch.

Interconnector Flow Constraints

Unlike generic intraregional transmission constraints, interconnectors are explicitly modelled and have flow limits and have direction flow limits.

Regional Energy Balance Constraints

For each time-segment regional energy balance constraints equate regional demand to the sum of regional generation and imports/exports.

Regional Capacity Constraints

For each year regional capacity constraints require that the sum of regional capacity contributions exceed a level specified for the region. The specified regional capacity requirements adopted for this study were expressed in terms of the 10% POE annual peak demand and minimum reserve requirement (which incorporate the assumed IC flow and the MRL).

The capacity contribution of each generator is taken to be the installed capacity multiplied by a contribution factor. For other than wind generation for which the contribution factor is between 1% and 9% depending on region, the contribution factor for different technologies is dependent on their auxiliary power use.

2.1.2 Constraint Violation Penalties

In a linear program the solution is required to conform to all constraints. However it can occur (particularly in cases where there are many thousands of constraints as is the case here) that there is no solution that can conform to all constraints.

To address this, each constraint is constructed in a manner so that it can be violated by an amount say "v". The cost of violation is measured in the objective function at a cost equal to an assigned Constraint Violation Penalty (CVP) multiplied by the violation quantity v.

CVP's are typically assigned very high values (typically expressed as multiples of the MPC) in order to limit the level by which constraints may be exceeded. Constraints are assigned different CVP depending on the importance of having constraints limit any violation.

2.1.3 Decision Variables – Integer and Continuous

Decision variables are the outputs to be determined by the model. In this study the key decision variables were the entry timing of identified new entry generators (on a locational basis) and the timing of identified transmission upgrade options (noting that most identified new generation and transmission options will not enter). Other decision variables are the level of generator dispatch and interconnector line flows.

Decision variables can be represented as either integer or continuous values. For example, the commissioning of, and allocation of output from power generation plant, can be integer or continuous. For this study, generation is treated as a continuous variable in commissioning and operation but as an integer variable in retirement. Energy transfers on inter-regional interconnectors are continuous variables while transmission upgrades are integer (all or nothing).

2.1.4 Objective Function

The objective function measures the Net Present Value (NPV) of the cost over the study period. The model finds a solution that minimises the value of the objective function.

2.1.5 Model Outputs

The output from a linear programming least cost model is twofold. The most obvious is the "***primary***" solution that details the technologies used each year, the extraction, importing and exporting of energy, the investments in generation and transmission required etc. The second of equal importance is the so-called "***dual***" solution that provides shadow price of each binding constraint that is consistent with the primary solution. For example, the regional reserve constraint, transmission constraints, energy balance constraints. The shadow prices are the prices that would apply in a perfectly competitive environment.

Other information that can be obtained is the value of the objective function. In the study undertaken here this measured the cost of supplying demand noting the impact of constraint violation penalties.

In interpreting the prices it is important to keep in mind that the investment costs of existing and committed projects are not reflected in shadow prices. This means that prices for the early part of the projection period are not fully reflective of costs.

2.2 IES PROPHET Model

The IES PROPHET model was the model used in this study.

The IES PROPHET Model is a modelling tool established to undertaken both market simulation modelling and least cost economic modelling of power systems and markets. PROPHET has been used in the NEM for many years and is well established for use in this study. One of the advantages of the tool is the ability to share data between the simulation and least cost modelling "modes".

The least cost planning capability of PROPHET is referred to as the Planning Module. PROPHET's Planning Module implements a least cost planning objective which aims to minimise the aggregate system discounted costs (including capital, operation, fuel and environmental policies) over the study period subject to relevant constraints including regional energy balance constraints, network security constraints and regional capacity constraints.

For this report the model is referred to as the PROPHET Planning Module, linear program least cost model, or simply the least cost model.

3 The TFTR Model

The first step in the study was to clearly describe the TFTR Model. This description is presented in the chapter.

3.1 Overview

The basis of the TFTR model is incorporating the impact of (selected) constraints on location prices (referred to a Pseudo Nodal Prices or PNP) which generators are settled on, and allocating Constraint Support Contracts (CSC) that provide the right to a component of the residues of the binding constraints thus proving a hedge for that contract quantity to the Regional Reference Node (RRN).

The binding constraint has associated non-zero price, referred to as the Constraint Support Price (CSP) that represents the marginal value of increasing the constraint by 1 MW. The associated residue is equal to the constraint limit multiplied by the CSP. Consequently the TFTR and SACP models are also referred to as the CSP/CSC mechanism.

The CSP/CSC mechanism adjusts the settlements of each generator impacted by a binding transmission constraint where their generation level appears on the LHS of that constraint. The calculation is done over all transmission constraints included in the scheme.

The SACP and TFTR models differ in the allocation of CSC quantities to generators. This is also referred to as a Financial Capacity Right. The differences are as follows:

- The SACP model allocates CSC to generators (and interconnectors) dynamically each dispatch period based on assessed availability of generators and interconnectors.

  The level of allocations given to an interconnector is not its nominal capacity as this may not a good indicator of its actual capacity. Instead the “next most binding constraint” has been recommended.

  A key feature of the SACP model is that there is no ownership of CSC as these are allocated on the same basis to incumbents and new entry generation/interconnection.

- The TFTR model has CSC to generators (and interconnectors) pre-determined based on agreements with the appropriate TNSP. The general principles of allocation are on a “first in basis”:
  - Existing available capacity is allocated at no charge to existing generators (and interconnectors) impacted by that constraint up to their nominal capacity.

    The capacity allocated to interconnectors needs to consider published limit equations and the appropriate share of interconnector access against other generators. This involves a consideration of the rights of the settlement residue units.

- New generators developing at a location would be allocated access rights to the extent it is available, and if not available would need to negotiate with the TNSP for access right (if required). This could involve paying for transmission augmentation.
- The rights are non-firm so if the transmission asset owner cannot deliver the contracted availability all rights holding generators behind the constraint will be constrained back in proportion to its contracted rights[1]. Generators are not required to take rights and can take on an "as available" basis.

The economic impacts/benefits of the SACP and TFTR models to the market are as follows:

- Both models resolve the disorderly bidding incentive as there is no spot market incentive remaining to bid away from costs to gain volume. An efficiency gain associated with the removal of disorderly bidding (what AEMO have termed productive efficiency) is therefore ascribed to both models.
- Because the SACP model does not discriminate against existing and new entrants (could be said to provides a degree of "free" access to new entrants in congested locations), it provides little or no change to locational or investment efficiency over the status quo. Therefore dynamic efficiency benefits of this model are considered to be very low.
- By providing pre-defined access rights to generators that cannot be diluted by new entrant plant, the TFTR model properly signals the capacity available to new entrants, the locational risks, and the costs of acquiring financial capacity rights. Consequently the TFTR model should provide dynamic efficiency benefits.

3.2 Simple Illustrative Example

The TFTR model involves the following steps:

- Step 1: determine the usual market revenue to generators as referenced by the RRP;
- Step 2: where there is a constraint, determine the "local" constrained price (this is the price determined by the bids received at the point of congestion). This is referred to as the PNP;

[1] The transmission asset owner will not be required to compensate rights holders for failure to provide the availability contracted causing the generator to still be subject to residual constraint risk. The transmission asset owner will instead face incentives/penalties in meeting their contracted availability targets which should deliver efficiency gains.

- Step 3: adjust the generators' market revenue to the revenue determined by the price determined under Step 2 and a static allocation that is negotiated between the generator and TNSP.

This is illustrated by a simple example below.

3.2.1 Example 1 – Single Generator in Constraint

- Generator G1
  - Capacity is 400MW
  - as bid $20/MWh
  - is constrained to the RRN by the binding constraint: 0.5 x G1 < 100
  - G1 dispatch is 200 MW
- RRN price is $50 representing the marginal cost of supplying additional demand at that node
- Constraint Support Price (CSP) is the value of increasing the constraint by 1MW = increasing G1 by 2 MW and decreasing $50 generation by 2MW = $60/MWh

<u>Status Quo Settlements</u>

- G1 paid $50/MWh x 200MW = $10,000

<u>TFTR Model</u>

- Assume G1 has been allocated 100% of the constraint residue. This corresponds to a Constraint Support Contract of 100MW.
- Pseudo Nodal Price (PNP) at G1 location: $50 - (0.5 x $60) = $20
- Residue available for allocation: 100MW x $60/MWh = $6,000
- Settlements:
  - Local price revenue: 200MW x $20 = $4,000
  - Residue allocation: $6,000
  - Total G1 revenue: $10,000
  - Operating surplus (revenue less costs): $6,000

If G1 had been allocated less than all the constraint revenue then it would not be perfectly hedged to the RRN.

<u>SACP Model</u>

Same result as for the TFTR model as all residue would be allocated to G1

3.2.2 Example 2 – Two generators at the Same Location

A new generator G2 of capacity 400MW is built and the constraint equation changes to

(0.5 x G1) +(0.5 x G2) < 100

- RRN price is $50/MWh
- Bids

- Generator G1 $20/MWh
- Generator G2 $10/MWh

- Dispatch levels
  - Generator G1 0MW
  - Generator G2 200MW
- Constraint Support Price (CSP) is the value of increasing the constraint by 1MW = increasing G2 by 2 MW and decreasing $50 generation by 2MW = $80/MWh

<u>Status Quo Settlements</u>

- G1 paid $50/MWh x 0MW = $0
- G2 paid $50/MWh x 200MW = $10,000
- There are incentives for both generators to bid at the price floor in order to receive $50 price

<u>TFTR Model</u>

- Assume G1 has been allocated 100% of the constraint residue. This corresponds to a Constraint Support Contract of 100MW.
- Pseudo Nodal Price (PNP):
  - at G1 location: $50 - (0.5 x $80) = $10
  - at G2 location: $50 - (0.5 x $80) = $10
- Residue available for allocation: 100MW x $80/MWh = $8,000
- Settlements:
  - G1
    - Local price revenue: 0MW x $10 = $0
    - Residue allocation: $8,000
    - Total revenue: $8,000
    - Operating surplus: $8,000 (G2 has not impacted G1's profit)
  - G2
    - Local price revenue: 200MW x $10 = $2,000
    - Residue allocation: $0
    - Total revenue: $2,000
    - Operating surplus: $0 (based on bid)

If G1 had been allocated less than all the constraint revenue then it would not be perfectly hedged to the RRN.

<u>SACP Model</u>

- Allocation of constraint residue based on availability multiplied by contribution to constraint:
  - G1 availability x contribution: 400MW x 0.5 = 200MW
  - G2 availability x contribution: 400MW x 0.5 = 200MW

  - RRNShare for both G1 and G2 = 50%
- This corresponds to a Constraint Support Contract of 50MW each.
- Pseudo Nodal Price (PNP):
  - at G1 location: $50 - (0.5 x $80) = $10
  - at G2 location: $50 - (0.5 x $80) = $10
- Residue available for allocation: 100MW x $80/MWh = $8,000
- Settlements:
  - G1
    - Local price revenue: 0MW x $10 = $0
    - Residue allocation: $4,000
    - Total revenue: $4,000
    - Operating surplus: $4,000 (G2 has impacted G1's profit)
  - G2
    - Local price revenue: 200MW x $10 = $2,000
    - Residue allocation: $4,000
    - Total revenue: $6,000
    - Operating surplus: $4,000 (based on bid)

If G1 had been allocated less than all the constraint revenue then it would not be perfectly hedged to the RRN.

A general description of the TFTR model arrangements are presented in Appendix B.

4 Approach to Representing the Status Quo and TFTR Model

As stated in the objectives of this assignment, the study is to model the dynamic efficiency benefits associated with the implementation of the TFTR model. It was also requested that the modelling be undertaken using a least cost economic model.

The approach used was to model the investment profile of generation and transmission under (1) the current regime, i.e. status quo and (2) with the TFTR Model, and then to compare the results.

The approach used for each of the cases (current regime and with the TFTR Model) was designed to satisfy the following to the extent possible:

1. Transparent and reproducible;
2. Rationale investment in generation;
3. Appropriate and reasonable representation of transmission security constraints;
4. Transmission investment undertaken by TNSP's according to current policy (RIT-T);
5. For the TFTR model, a supportable basis for capacity rights capacity assessment and allocation.

Also the assumptions were to be based on the current market outlook in terms of supply costs, loads and policy;

4.1 Issues to Approach Development

The use of a least cost model, while providing advantages in some areas, introduced restrictions in others. The key advantages were the economic basis (points 2 and 4 above), reproducibility (point 1 above), and logistics (fast turn-around time).

The disadvantage was that models of this type have no concept of different settlements arrangements as would be introduced by the TFTR model, and no concept of market behaviour dynamics associated with new entry location decisions. The representation of these differences would need to be undertaken by "non-explicit" means.

The representation of security constraints was provided by AEMO and these were the security constraints developed for the NTNDP 2010 studies. These can be applied to both simulation and least cost planning models.

The outlook assumptions were based on public information consistent with the current outlook that has significantly lower demand growths than AEMO was projecting in 2011. This would mean a reduced sensitivity to the requirements for new generation and transmission. For comparison purposes, IES also undertook the studies on the load forecasts and assumptions used in the 2010 NTNDP studies.

4.2 Representing New Generator Locational Decisions

The key issue for the modelling was to represent the differences between how new generators would locate under the status quo (ie no TFTR model) and with the TFTR model implemented. As noted above, least cost planning models do not provide for an explicit representation of the changed arrangements associated with these two cases. The approach adopted is discussed below.

4.2.1 The Status Quo

Currently there are no access rights to generators and generators face constrained off risk. The RIT-T specifies the economic and regulatory basis for transmission upgrades. The question is how the current arrangements translate to material congestion issues in the future, and how the economic value of upgrading transmission compares to the financial risks that congestion may present to locating generators.

The economic consequences of congestion and the financial consequences to individual generators can be substantially different. For example, a constrained off coal generator that is contract long at times of very high spot prices faces large financial losses, but if this constrained generation is replaced by another coal generator then the economic impacts are small (being the quantity of constrained generation priced at the difference in fuel costs). Thus not all congestion that presents significant risks to generator may be addressed by TNSP’s under the RIT-T.

Such risks are particularly material to non-intermittent generators that intend to contract firm capacity. The result of this is that there are locations in the NEM where generators will not build and others where great caution would be required. However, the economic costs of constraints as measured by a modified dispatch pattern (and as assessed by a least cost economic model) are likely to be small, and may in no way represent the financial risks to new entrants in entering at certain locations.

The modelling needed to represent the incentives on new entrant location decisions that constraint risk may provide.

As decisions in least cost models are determined through minimising the objective function cost, the approach was based on measuring risk through the level of the constraint violation penalties. Low values implying low risk and high values high risk.

For the status quo, the approach used was to have generator entry decisions based on the current transmission (remains fixed) and to modify the constraint violation penalties on the transmission constraints to represent varying levels of risk.

In proposing this approach it was understood that future generator entry decisions would be based on knowledge of transmission developments undertaken or committed at that time, but this was considered not to be a critical issue.

The logic was that higher constraint violation penalties on transmission constraints would reflect higher risks on the investment decisions at locations where there was potential congestion. It was proposed that changes to constraint violation penalties would be done on all transmission constraints:

- A very low violation penalty would imply a low level of risk associated with any current constraints. This may imply an assumption that any constraints would be built out by the appropriate TNSP;
- A very high violation penalty would imply a high level of risk associated with any current constraints. This may imply a concern that any constraints would not be built out by the appropriate TNSP or additional new generation would aggravate the situation;
- A violation penalty near the cost of building out any constraints would imply a level of co-optimisation between generation and transmission development. This might be expected under the TFTR model.

With the resulting generation development program determined (incorporating congestion risk) the transmission investment decision would be made. This could be thought of as transmission investment following generation investment decisions and is consistent with the current pricing arrangements.

4.2.2 TFTR

The proposed TFTR regime can be thought of as generators paying for additional transmission required to provide access rights to the RRN price. If no additional transmission is required then access rights are allocated at no cost. Available capacity is assigned on a “first in” basis.

Ignoring issues such as fuel availability and the nodal/regional price outlook, the result of this regime should have new generators enter in regions of highest price and at locations with the lowest cost of transmission access. Initially this would be in areas with spare transmission capacity. Once all spare capacity is exhausted, the costs of transmission upgrades would start to increase as generators locate in the most easily upgradable areas first. It is noted that transmission upgrades are also needed to supply increasing demands which in turn brings on the requirement for new generation.

The modelling approach to the representation of the TFTR model needed to recognise the trade-off being made by a new entrant generator between location and transmission upgrade costs. This was represented by co-optimising generation and transmission development in the model.

While it is recognised that this would provide a reasonable representation of the TFTR arrangements there are some differences (such as the inter-temporal nature of the optimisation).

4.3 Of particular note also is that the modelling does not entail any explicit consideration of access rights as these are implicit in the modelling. Locational Risk

As discussed in the introduction to this report, transmission constraint issues and uncertainty regarding whether or not these constraints would be built out by TNSP's has given rise to locations in the NEM that are viewed as high risk locations and unlikely to see new generators locate there.

To test the sensitivity to having different risks associated at different locations in the absence of the TFTR, model, modelling of the status quo was undertaken with new generator capital costs increased at some locations to emulate the impact of increased risk.

5 The Transmission Model

A significant challenge in this study was the representation of transmission security constraints and the options and costs of upgrading the network when required. Here we distinguish between connection assets, extension assets and the shared network. The modelling in this study considered only the shared network.

5.1 2010 NTNDP Equations

Equations

The 2010 NTNDP equations were provided by AEMO and were used for this work. These were provided via a PROPHET database that contained the 2010 NTNDP equations.

There were over 800 constraint equations incorporated with most of them having generator dispatch level and interconnector flow terms on the LHS.

The 2010 NTNDP equations have the advantage of being current and having a well understood basis. Their disadvantage is that augmentations are not clearly identifiable, assumptions are needed in relation to the physical meaning of increasing the RHS of a constraint, the coefficient terms in the equations remain unchanged in the presence of new transmission, and that locations for new generators are limited to locations when there is already a generator term.

RHS Terms

Many of the RHS's of the generic constraints contained parameters that can be obtained from the result of a previous solution in a simulation model, such as regional load, generator outputs, link flows etc. These terms can significantly impact the value of the RHS, reflecting the nature of such constraints. Accuracy of modelling would required that the transmission constraint equations be entered into the least cost model with the RHS terms calculated based on the expected conditions in each time segment and year.

The form of a least cost linear programming model does not provide for these to be updated in time as the RHS terms must be presented to the LP already calculated. To provide RHS terms consistent with the conditions in each of the time sectors, the RHS terms were determined through a prior simulation run.

This involved running the PROPHET model in simulation mode prior to running PROPHET in least cost planning mode. The simulation mode provided the forward looking projections of the terms included in the RHS constraint terms. However future years of the simulation needed to have knowledge of generator entry and location determined by the planning model. To address this, the modelling did an iteration of the least cost planning model, simulation model and then final least cost planning model.

5.2 Transmission Upgrade Options

Information on potential transmission augmentations was provided by AEMO through a constraint equation spreadsheet and the augmentations contained in the PROPHET database that were published with the 2010 NTNDP.

A separate spreadsheet on augmentation costs was provided for this study. The information in this spreadsheet described the augmentation works and associated costs, and did not cross reference the constraint equation spreadsheet. The matching of potential upgrades, costs and associated constraint equations was undertaken by IES.

The augmentations contained in the constraint equation spreadsheet and the PROPHET database were compared and the following noted:

- Not all augmentations modelled in 2010 were included in the cost spreadsheet;
- The project number and description did not match exactly with those in the 2010 NTNDP constraint equations spreadsheet;
- Almost half of upgrade options had no impact on constraints modelled;
- About 20 options could not be found in the Prophet database;
- Some upgrades were repeated in the same scenario;
- Some upgrades had different constraint impacts in different scenarios;
- Different options had the same effect (e.g. new transformer at different locations -> V>>V_NIL_2A_R RHS increases by 100).

The transmission upgrade options modelled were those that satisfied the following:

- Exist in both the cost spreadsheet and the Prophet database;
- Had an impact on the NTNDP constraint equations;
- Could be represented in the least cost model[2].

Overall, 40 upgrade options were included, with 225 (approximately 25%) of all generic constraints impacted.

5.3 Representing Transmission Development

Under the least cost modelling approach new generation and transmission enters in response to minimising the cost of meeting demand. While generation also

[2] The following changes to constraint equations after an upgrade could not modelled in the least cost model and were excluded:

- Changing values of sub-equation (upgrade options V28 and V35);
- Removing connection point in constraints (upgrade option N1).

has a constraint on satisfying regional reserve criteria this corresponds to the economic basis of the NEM.

The picture for transmission however is slightly different. The key drivers for transmission investment are:

- Market benefits for interregional transmission development;
- Reliability criteria and market benefits for intraregional transmission development (the RIT-T specifies that all transmission developments must incorporate market benefits).

The reliability criteria for intraregional transmission investment in all states except Victoria are very stringent and result in developments that would not occur through considerations of market benefits alone (noting that these benefits include the cost of violation as specified through the CVP). These criteria are shown in the table below.

This combined with the assumption of system normal transmission constraints means that the modelling will not identify the transmission development that would occur under the current planning regime of reliability and market benefits.

To identify the sensitivity of transmission developments to the assumptions and approach used in the least cost modelling, a sensitivity run was undertaken where the limits of the transmission constraints (as specified by the RHS's) were reduced by 20%. The logic being that the increased market benefits associated with a more limited transmission network would be a surrogate the more stringent criteria used by the respective TNSP's.

Table 5-1 State Transmission Planning Criteria

State	Transmission Planning Criteria
South Australia	Cater for any one line out of service and the worst generator combination at time of 10% POE demand level
Victoria	Probabilistic assessment of unserved energy across conceivable power system conditions
Tasmania	Cater for no credible contingency event interrupting more than 25 MW of load and no single asset failure interrupting more than 850 MW or, in any event, cause a system black
New South Wales	Cater for any one line out of service and the worst generator combination at time of 10% POE demand level
Queensland	Cater for any one line out of service and the worst generator unit for that line outage at time of 10% POE demand level

6 Modelling Steps

Based on the descriptions above of the PROPHET Planning Module, the approach to representing the status quo and TFTR in a least cost model, and the representation of transmission constraints, this chapter presents the modelling steps undertaken in this study.

6.1 Model Development and Operation

This section outlines the sequence of steps undertaken in the modelling. Details of each step cans be found in earlier sections of this report.

Step 1 – Market Outlook Assumptions

The first step was to establish the assumptions for use in the study. Two sets of modelling runs were undertaken based on different sets of assumptions. These were:

- NTNDP 2010 assumptions. These had significantly high load growth than in the current outlook and thus would be expected to provide a greater stress on the transmission system;
- Current Market Outlook base on the 2012 NTNDP assumptions and updated regional load growths.

Step 2 – Development of Transmission Security Constraints

This involved developing/implementing:

- The transmission security constraints for use in the model;
- The potential transmission upgrade options available over the study period in terms earliest year the development could enter and the cost of the upgrade.

Step 3 – Set-up Least Cost Model

The set-up of the model involved:

- Study period 2011/12 to 2030/31;
- All costs are adjusted to be in 2012/13 real dollars;
- Regional model with co-optimised generic constraints;
- NTNDP zones recognised – new entry generation location vary by zone;
- Establishing annual time sectors (each year is divided into a number of time sectors)
  - 3 seasons (Summer, Winter and Intermediate);
  - 9 time sectors per season per year;
  - top 5 time sectors representing the 10% maximum demand condition for each of the NEM regions;

- Populating the model with the market outlook assumptions (regional annual energy and maximum demand profiles, fuel costs, existing generators, existing interconnection, regional reserve requirements etc);
    - Fuel costs that varied by NTNDP zone
- Establishing the network represented via the NTNDP equations. For each constraint, this required the constraint limit (as expressed through the RHS term) being calculated via simulation modelling for each time sector to match the conditions expected (load, expected generation etc) of that time sector.
- Non-renewable new generator options were identified in terms of type (OCGT, CCGT) in each zone. These options were entered in the model. These options were included in the transmission constraints equations if and when they entered the market;
    - New entry capital costs the same in all zones. The model assumed the same connection costs in all zones.
- The rules of the Large-scale Renewable Energy Target were included in the model. Renewable generation options were identified and were included in the model. Such generators produced and were paid for created LGC's at the economic price. (Generators were classified into those that create LGC's and those that do not.) This meant that the modelling would produce the LRET price;
- The modelling included the Carbon pricing scheme (CPS) via a price on carbon emissions based on a projected profile;
- Regional capacity constraints as per AEMO reserve requirements. All generators were assigned a capacity contribution (depending on plant type).

Step 4 – Status Quo Modelling

Based on the modelling assumptions:

- Generation development modelled with fixed intraregional constraints included under 3 scenarios:
    - Low violation penalties (1 x VoLL)
    - Moderate violation penalties (10 x VoLL)
    - High violation penalties (40 x VoLL);
- With the resulting generation development program fixed, the model was run to develop a transmission development program. The transmission constraint violation penalties in this were set as High (40 x VoLL).

The modelling of the status quo contained three cases based on the level of the constraint violation penalty used in the first step.

Step 5 – TFTR Modelling

The model was run with generation and transmission co-optimised. The constraint violation penalties on transmission constraints were set at 40xVoLL.

This produced one case only.

Step 6 – Comparison of Results

From the results of the status quo and TFTR modelling differences in the investment profiles was obtained in additional to other modelling outputs that are explained.

7 Assumptions, Outputs and Interpretation

Before presenting the results of the studies, this chapter presents a summary of the market assumptions used, the modelling results presented, and the manner the results have been interpreted.

7.1 Market Assumptions

Two sets of model runs were undertaken.

Scenario 1 – Expected Market Outlook

These were designed to represent the expected conditions:

- Load growth: Low growth over the first 4 years moving to a medium level of growth;
- Gas and coal costs: As per the 2012 NTNDP Consultation – Scenario 3 (Planning Scenario) Sensitivity 4;
- Carbon Price: Treasury Core Policy scenario;
- Capital, fixed and variable O&M costs as per the 2010 NTNDP and adjusted to 2012/13 dollars.

Scenario 2 – NTNDP 2010 Assumptions

This case used the assumptions of the 2010 NTNDP Scenario 3 Medium CPT (15%)[3]. This was chosen as the higher level of load growth and carbon price from that now anticipated would provide for greater differences in the runs to be observed.

The details of the assumptions used in each of the above scenarios are presented in Appendix A.

7.1.1 Generator Developments Costs

Without some basis for changing, the modelling has assumed the cost of developing generation of the same technology to be the same in all zones in the NEM. Technologies have been limited to renewable generation and OCGT and CCGT plant. However it may be that different locations have different costs for developing generation for reasons such as proximity to fuel sources and high voltage transmission, civil works required etc.

7.2 Modelling Outputs

As described, the least cost model was developed with 27 time segments per year and the results contain the solution for each of these time periods. To

[3] The document “Valuing Proposed Access Models” prepared by Frank Cavoli (dated 21 November 2011) suggested to “use NTNDP projections (Medium growth-medium carbon price trajectory – new entry) to forecast new generation investments”.

obtain annual values, the results of the time sectors are summed accounting for the different number of hours each of the segments represents in a year. In this report all results are presented on an annual basis although the results for individual segments are available if required.

The key outputs of the least cost modelling undertaken, categorised by primal solution, dual solution, and objective function, are described below.

Primal Solution

These are the physical outcomes of the solution:

- Generator developments – MW's built by generator type, year, and zone;
- Generator dispatch – each generators production (GWh) by year;
- Transmission developments – the year each of the pre-specified transmission upgrade options enters;
- Unserved energy each year;
- The number of hours each constraint was binding by year.

Dual Solution

The results are or based on the shadow prices of the constraints in the model:

- The marginal cost of each transmission constraint by year (for each transmission constraint this is marginal value multiplied by the number hours it was constraining)
- The marginal price of the energy balance constraint in each NEM region by year (average over the time segments each year);
- The marginal value of the reserve capacity constraint in each NEM region by year (average over the time segments each year);

The average regional spot price can be constructed by combining energy balance and reserve constraint marginal values.

Objective Function

The value of the objective function for each model run is the NPV (at a specified discount rate) of all the costs associated with supplying demand:

- Generator development costs;
- Transmission development costs;
- Generator dispatch costs (O&M and fuel);
- Unserved energy costs (valued at the MPC);
- Carbon emission costs;
- Purchase of shortfalls of LGCs;
- The cost of constraints violated at their respective Constraint Violation Penalty.

Thus the objective function provides a measure of the economics of each solution. A lower value for the objective function would imply that demand over the study period is being met at a lower economic cost.

Here we note that the contribution to the objective function of constraint violation penalties do not represent any economic costs are can be removed for the purposes of comparing the economics of scenarios. This was the approach taken here.

7.3 Interpretation

Before presenting the results of the least cost modelling we make the following observations in relation to the modelling outcomes:

- The low level of load growth, the use of “system normal” constraints, and the observation that most intraregional transmission is developed on the basis of reliability standards indicates that there is unlikely to be any significant level of transmission development;
- The above may be despite the modelling showing considerable hours of transmission constraints binding;
- As the cost of developing generation was assumed to be the same in all zones, the economic cost of moving generation from one zone to another (due to transmission constraints) as measured by the objective function will be zero;
- The main economic cost expected is expected to be associated with different types of generation being developed (for example more wind generation) and transmission upgrades, which may not be significant.

However, while not measured in the objective function, there is a cost to developers from locating generators in locations not preferred and in the risks presented by transmission constraints.

Consequently, for the purposes of evaluating the economics of the TFTR model compared to the status quo, a risk premium on relocating generation was implied. The premium was taken by to be 30% of development costs. While arbitrary, this figure is well within the range of costs that would be expected in a tender process for the development of power system assets such as a power station or transmission line.

8 Modelling Results – Most Likely Outlook

This chapter presents and discusses the modelling results of the Most Likely Market outlook scenario. There were 4 cases associated with this scenario:

- Status Quo under three levels of CVP for transmission constraints. These were labelled Low CVP, Moderate CVP, and High CVP. These represented the assessed risk of transmission constraints in the status quo case;
- TFTR Model – represented the market assuming the TFTR was implemented.

Detailed results are presented in Appendix C.

8.1 Key Results

The key results for the study and presented below are as follows:

- The total economic cost of the 4 cases modelled as determined through the objective function results (excluding the cost of constraint violation penalties);
- The change in generator capacity by location. This is shown for the Low CVP and High CVP cases;
- Transmission upgrades that occurred and their timing;
- The sum of the Cumulative Marginal Costs (CMC) for all transmission constraints.

8.1.1 Measured Economic Cost

The table below shows the economic costs and the differences compared to the TFTR case. The costs are quite small reflecting the issues discussed in the previous chapter. Of note is that the TFTR case does have the lowest economic cost and the Status Quo – Low CVP case has the highest economic costs.

Table 8-1 Most Likely Scenario – Total Discounted Costs ($Millions)

Discounted Costs @ 9.79% ($Millions)	Status Quo Low CVP	Status Quo Moderate CVP	Status Quo High CVP	TFTR
Generation	74,882.9	74,853.0	74,852.6	74,835.3
Investment (including fixed O&M Costs)	12,562.5	12,652.9	12,660.8	12,648.1
Transmission Upgrade	46.7	46.7	47.6	47.6
Unmet Load	150.8	-	-	-
Total Discounted Costs (excludes violation penalty)	**87,642.8**	**87,552.6**	**87,561.0**	**87,531.1**
Difference in Total Discounted Costs compared to TFTR Case	111.7	21.5	29.9	

8.1.2 Change to Generation Entry

The changes to generator capacity by location from the Status Quo (for the Low and High CVP cases) to the TFTR cases are shown in the figures below.

Figure 8-1 Most Likely Scenario – New Generation Capacity Changes Change from Status Quo Low CVP to TFTR Cumulative MW

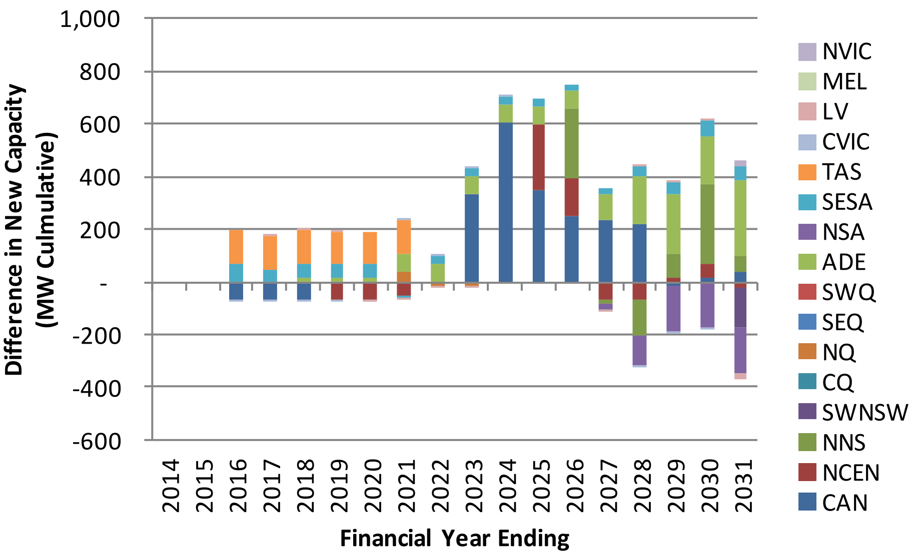
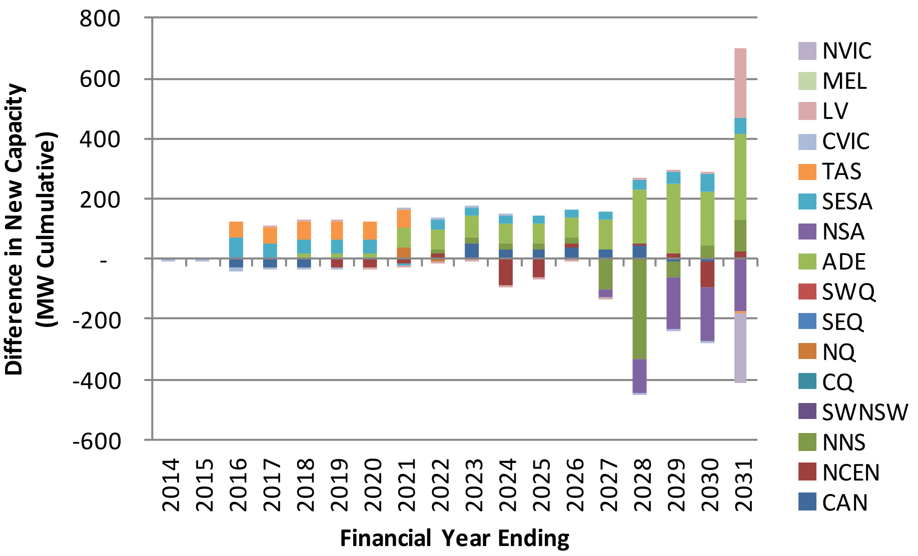


Figure 8-2 Most Likely Scenario – New Generation Capacity Changes Change from Status Quo High CVP to TFTR Cumulative MW



Before discussing in more detail below, we note that the changes are not totally symmetrical. In other words reductions in one zone are not precisely matched with increases in another. Symmetry of this nature may have been expected if all regions in the NEM had installed capacity equal to their respective Minimum Reserve Level. However this is not always the case (particularly in the early years when there is a capacity overhang) and renewable generation has a reduced contribution to reserve capacity.

As expected, the Status Quo Low CVP case, through largely ignoring transmission issues when planting generation results in generators entering in locations that would not occur under the TFTR arrangements. However the Status Quo High CVP case by incorporating transmission issues in the planting decision results in a closer solution to that under the TFTR arrangements

8.1.3 Transmission Development and Performance

The tables and figures below show the timing of transmission developments, the number of binding constraints and the sum of the CMC over the study period.

The results show:

- The number of constraints that bind increases at a fairly uniform rate in response to increasing demand growth and increasing transmission flows;
- Only 4 transmission upgrade options entry, and the difference between the 4 cases is a delay in one year for option S6 (a minor development in South Australia).

As far as economic impacts to transmission develop from improved locational pricing, the modelling failed to identify such benefits. As previously noted, this was not unexpected given that any developments would be based on market benefits alone.

Table 8-2 Most Likely Scenario – Transmission Upgrades Timings

Dev No	Description	Status Quo Low CVP	Status Quo Moderate CVP	Status Quo High CVP	TFTR
S9	Install the third South East 275|132 kV transformer	2015	2015	2015	2015
QN1	Series compensation on the 330 kV Armidale-Dumaresq circuits and 330 kV Dumaresq-Bulli Creek 330 kV circuits	2022	2022	2022	2022
S6	Uprate the 275 kV Para-Brinkworth-Davenport circuits from 65°C to 80°C	**2027**	**2027**	2026	2026
S1	Increase the ratings of both 275 kV Torrens Island B-Kilburn and Torrens Island B-Northfield circuits to line design ratings by relevant protection and selected plant modifications	2029	2029	2029	2029

Figure 8-3 Most Likely Scenario – Sum of Cumulative Marginal Costs $M/MW

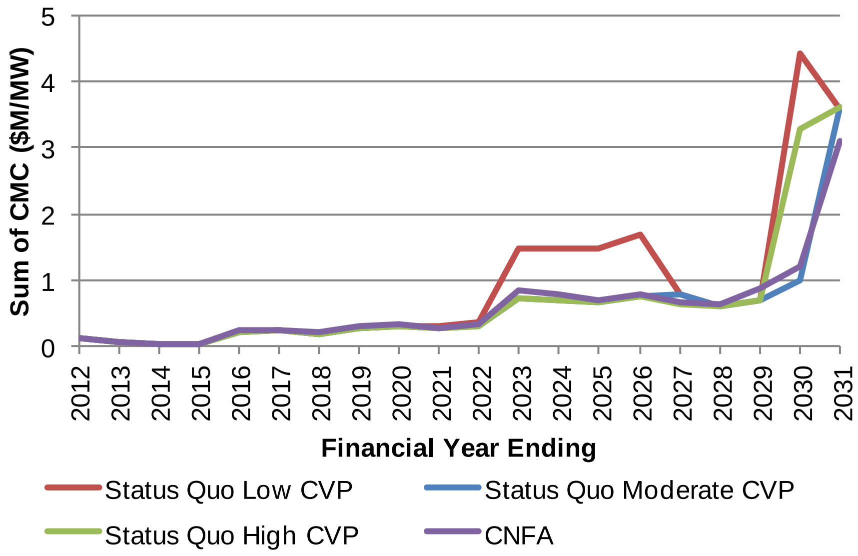
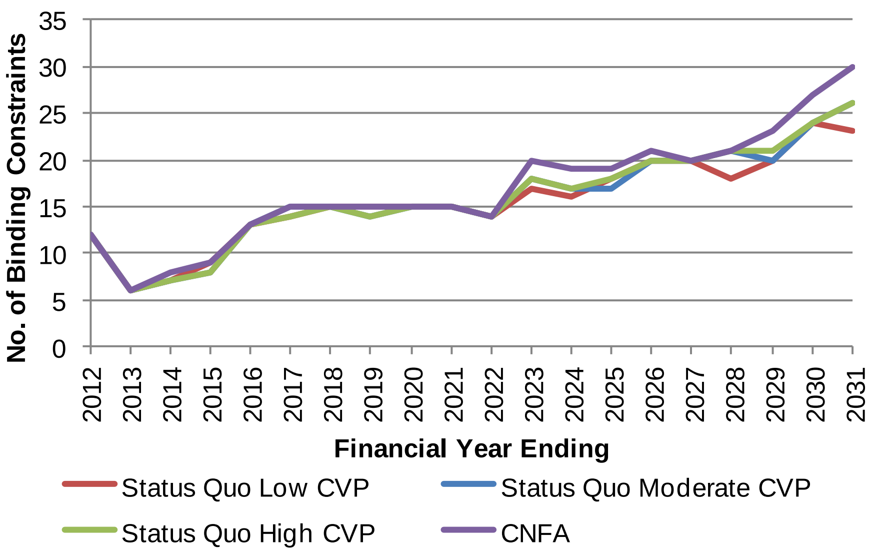


Figure 8-4 Most Likely Scenario – Number of Binding Constraints



The modelling did identify the increasing number of constraints that were binding and the increased stress on the transmission system. In this regard there was no great difference between the 4 cases. The modelling did identify a significant change to the sum of CMC between the Status Quo Low CVP case and the other cases that incorporated consideration of transmission in generator planting decisions.

8.2 Sensitivity to Transmission Limits

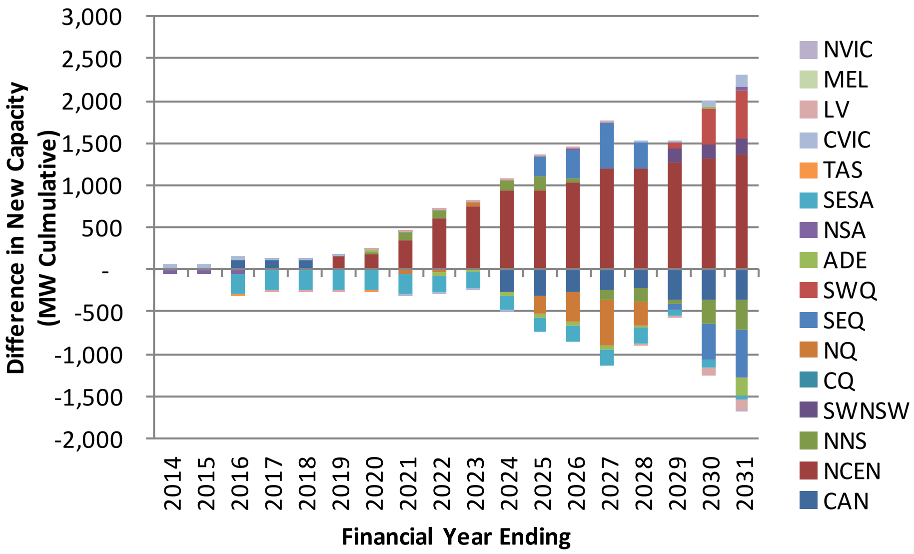
A model run was undertaken to investigate the sensitivity of transmission upgrade economics to the transmission limits used in the modelling. As previously explained, the concern is that by limiting the transmission investment criteria to market benefits (ie economic only) that transmission investment will be limited and not sensitive to changing generator patterns (due to a move to TFTR arrangements).

The least cost model was run for the Mostly Likely Scenario / TFTR with all intraregional transmission limits reduced by 20% and compared to the case with no reduction in transmission limits. The table and graph below show the differences in transmission development and the change in generator location planting.

Table 8-3 Most Likely Scenario – TFTR Model Differences in Transmission Development through Reducing Intraregional Transmission Limits by 20%

Dev No	Description	TFTR	TFTR with Reduced limits
N9	Upgrade high voltage 330 kV Ingleburn-Wallerawang Power Station connections (77)	-	2017
N15	Rearrange Central Coast 330 kV connections and install line series reactors-redistribute power flows	-	2019
S9	Install the third South East 275|132 kV transformer	2015	-
QN1	Series compensation on the 330 kV Armidale-Dumaresq circuits and 330 kV Dumaresq-Bulli Creek 330 kV circuits	2022	2022
S6	Uprate the 275 kV Para-Brinkworth-Davenport circuits from 65°C to 80°C	2026	2027
S1	Increase the ratings of both 275 kV Torrens Island B-Kilburn and Torrens Island B-Northfield circuits to line design ratings by relevant protection and selected plant modifications	2029	-
VS2	A third Heywood 500|275 kV transformer, a 100 MVAr capacitor bank at South East Substation, a third South East 275|132 kV transformer, increase of the relevant circuit ratings to line design ratings by protection and selected plant modifications	-	2028

Figure 8-5 Most Likely Scenario – TFTR Change in Generator Location through Reducing Intraregional Transmission Limits by 20%



We make the following observations:

- The reduction in limits resulted in additional transmission developments in NSW but also a removal of some developments. This shows that the developments are sensitive to the limits used (as would be expected) not only in terms of timing, but the actual developments required;
- Under the TFTR arrangements, reducing the RHS of constraints impacted to co-optimised solution fairly significantly. This illustrates the impact planning criteria would have not only to when plant was developed but where.

8.3 Interpretation

The modelling results as presented have demonstrated that an arrangement that provides risk mitigation against constrained-off risk would provide for improved decisions in relation to generator location and transmission development.

The economics as measured by the changes in development costs in the modelling undertaken did not recognise the cost associated with reduced risk, and had limited transmission development response to changing demand and location pricing arrangements by having intraregional transmission develop based on market benefits only.

Generation movements associated with the TFTR arrangements can be categorised into changes of technology and movements between zones. The former is included in the changed value of the objective function between the cases modelled. The latter was not included because the cost of generator planting was assumed to be the same in all zones.

The costs of changed generation over the study period varied between $29.9M and $111.7M based on a high to low risk assessment of transmission congestion in the status quo case.

As described above, the study assumed an increased in generator planting and risk associated with developing in a non-preferred zone. The premium was taken by to be 30% of development costs. Based on this the costs of plant movements were assessed. Based on this the costs of generator movements are determined to vary from $32.6M to $74.7M (at a 9.79% discount rate) based on a high to low risk assessment of transmission congestion in the status quo case.

This gives a total cost of generators relocating as varying between $54M and $186M over the study period. This is likely to be a significant underassessment.

The cost of changed transmission is negligible, although the sensitivity to the constraint limits indicates that there may be a considerable amount of value here.

9 Modelling Results – NTNDP 2010 Assumptions

This chapter presents and discusses the modelling results of the Scenario that used the assumptions of the 2010 NTNDP Scenario 3 Medium CPT (15%).

The modelling results are presented in the same order as for the Most Likely Scenario. There were 4 cases associated with this scenario:

- Status Quo under three levels of CVP for transmission constraints. These were labelled Low CVP, Moderate CVP, and High CVP. These represented the assessed risk of transmission constraints in the status quo case;
- TFTR Model – represented the market assuming the TFTR was implemented.

Detailed results are presented in Appendix D.

9.1 Key Results

The key results for the study and presented below are as follows:

- The total economic cost of the 4 cases modelled as determined through the objective function results (excluding the cost of constraint violation penalties);
- Transmission upgrades that occurred and there timing;
- The change in generator capacity by location. This is shown for the Low CVP and High CVP cases.

9.1.1 Measured Economic Cost

The table below shows the economic costs and the differences compared to the TFTR case. The costs are quite small reflecting the issues discussed in the previous chapter. Of note is that the TFTR case does have the lowest economic cost and the Status Quo – High CVP case has the highest economic costs.

Table 9-1 NTNDP 2010 Scenario – Total Discounted Costs ($Millions)

Discounted Costs @ 9.79% ($Millions)	Status Quo Low CVP	Status Quo Moderate CVP	Status Quo High CVP	TFTR
Generation	88,764.24	88,766.60	88,800.78	88,714.00
Investment (including fixed O&M Costs)	17,196.37	17,206.88	17,176.49	17,222.53
Transmission Upgrade	8.69	8.69	8.30	6.98
Unmet Load	55.71	28.38	42.21	-
Total Discounted Costs (excludes violation penalty)	**106,025.0**	**106,010.5**	**106,027.8**	**105,943.5**
Difference in Total Discounted Costs compared to TFTR Case	81.52	67.04	84.27	

9.1.2 Change to Generation Entry

The changes to generator capacity by location from the Status Quo (for the Low and High CVP cases) to the TFTR cases are shown in the figures below.

Figure 9-1 NTNDP 2010 Scenario – New Generation Capacity Changes Change from Status Quo Low CVP to TFTR Cumulative MW

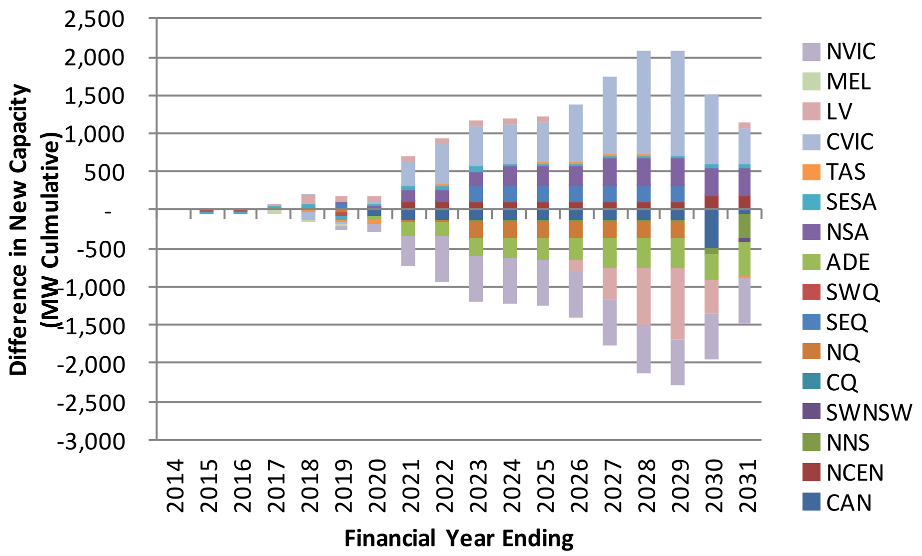
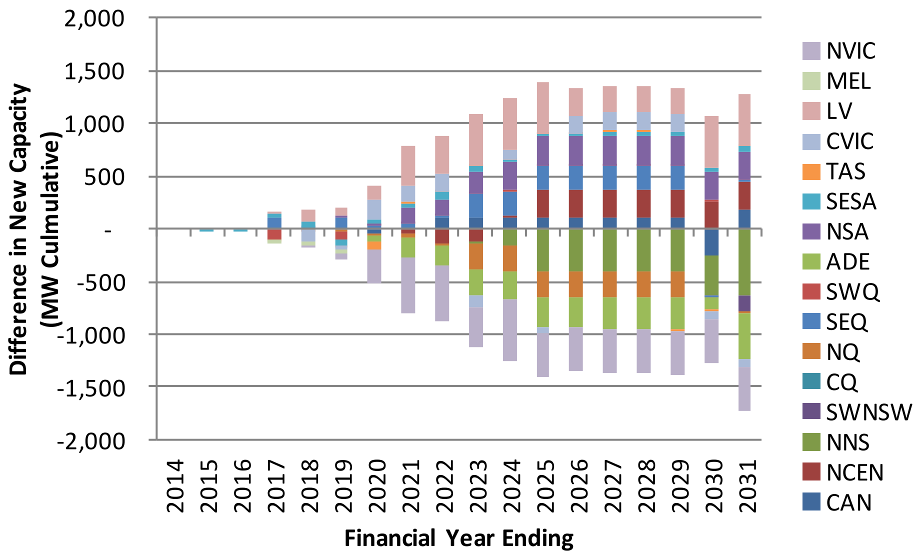


Figure 9-2 NTNDP 2010 Scenario – New Generation Capacity Changes Change from Status Quo High CVP to TFTR Cumulative MW



As expected, the Status Quo Low CVP case, through largely ignoring transmission issues when planting generation results in generators entering in locations that would not occur under the TFTR arrangements. However the Status Quo High CVP case by assuming constraints would not be built out results in generators entering in locations that have lower dispatch costs.

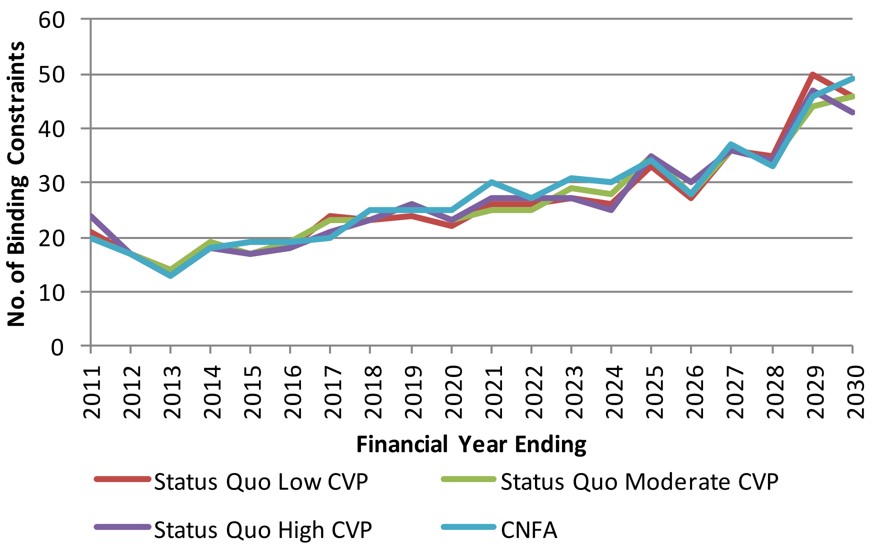
9.1.3 Transmission Development and Performance

The tables and figures below show the timing of transmission developments, the number of binding constraints over the study period.

Table 9-2 NTNDP 2010 Scenario – Transmission Upgrades Timings

Dev. No	Description	Status Quo Low CVP	Status Quo Moderate CVP	Status Quo High CVP	TFTR
T5	A new 220|110 kV transformer in the Hobart area	2023	2023	2023	2023
Q18	A new 275 kV Greenbank-Molendinar double circuit line	2027	2027	2027	2027
S1	Increase the ratings of both 275 kV Torrens Island B-Kilburn and Torrens Island B-Northfield circuits to line design ratings by relevant protection and selected plant modifications	2027	2027	2027	2027
S9	Install the third South East 275|132 kV transformer	2027	2027	**2028**	2027
S2	Increase the rating of the 275 kV Northfield-Kilburn circuit to line design rating by relevant protection and selected plant modifications	2028	2028	2028	2028
V22	A new 330|220 kV Dederang transformer (4th)	2028	2028	2028	2028
V28	A new 220 kV Ballarat-Moorabool line (3rd line)	2028	2028	**2029**	**2029**

Figure 9-3 NTNDP 2010 Scenario – Number of Binding Constraints



In this scenario, there was again no great difference between the 4 cases in terms of transmission development and performance. However the modelling did identify the increasing number of constraints that were binding and the increased stress on the transmission system.

The costs of changed generation over the study period varied between $67M and $84.3M based on a high to low risk assessment of transmission congestion in the status quo case.

As described in the previous section, the study assumed an increased in generator planting and risk associated with developing in a non-preferred zone. The premium was taken by to be 30% of development costs. Based on this the costs of plant movements were assessed. Based on this the costs of generator movements are determined to vary from $110.8M to $181M (at a 9.79% discount rate) based on a high to low risk assessment of transmission congestion in the status quo case. This gives a total cost of generators relocating as varying between $178M and $262M over the study period.

Appendix A Modelling Assumptions

This appendix presents a summary of the key assumptions contained in the two scenarios modelled:

- Most Likely Scenario;
- 2010 NTNDP Assumptions.

A.1 Load Forecasts

Figure 9-4 Most Likely Scenario - Annual Energy (GWh sent-out)

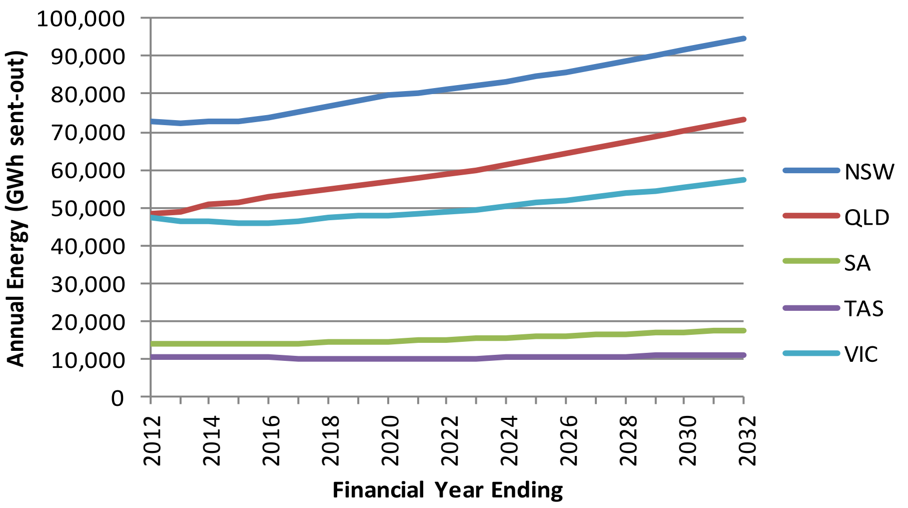
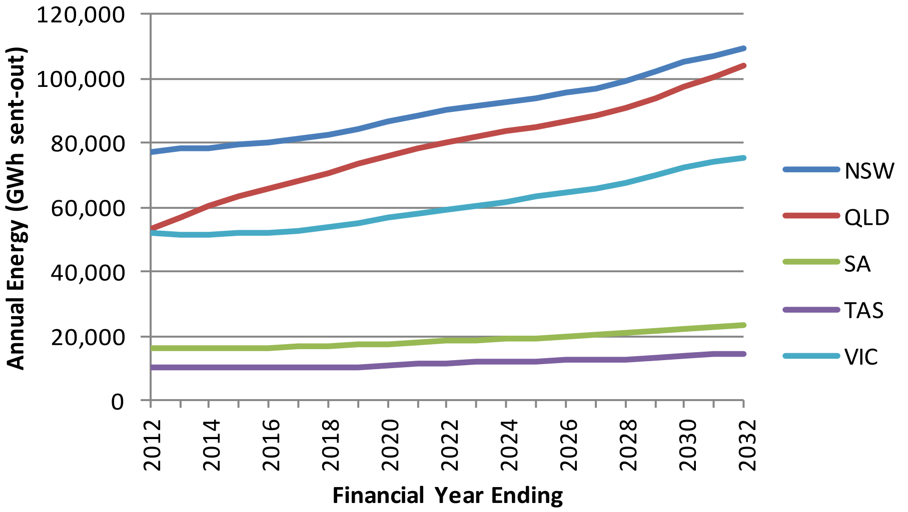


Figure 9-5 NTNDP 2010 Scenario - Annual Energy (GWh sent-out)



A.2 Gas Costs

Figure 9-6 Most Likely Scenario – Gas Costs for New CCGT ($/GJ)

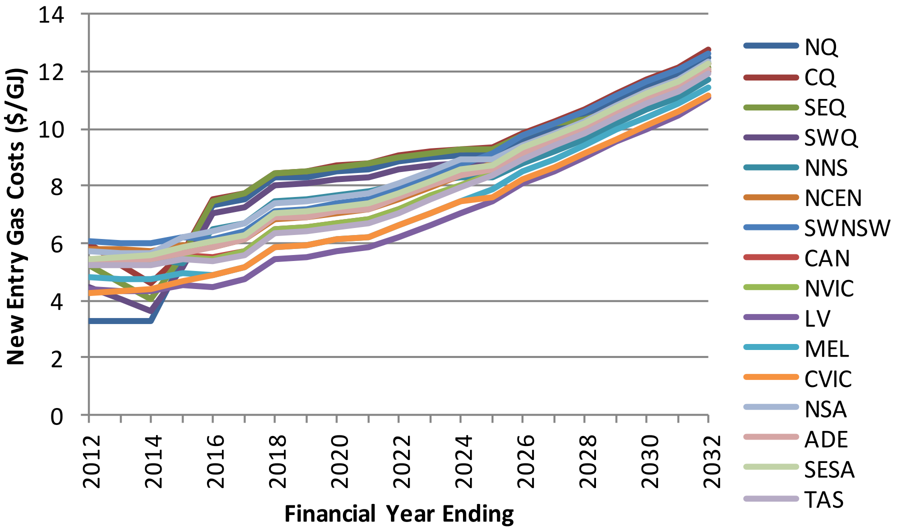
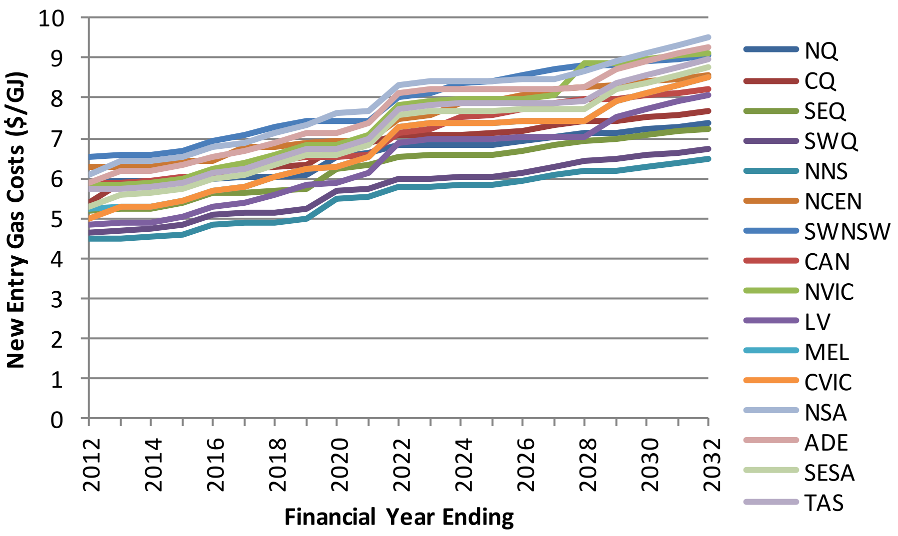
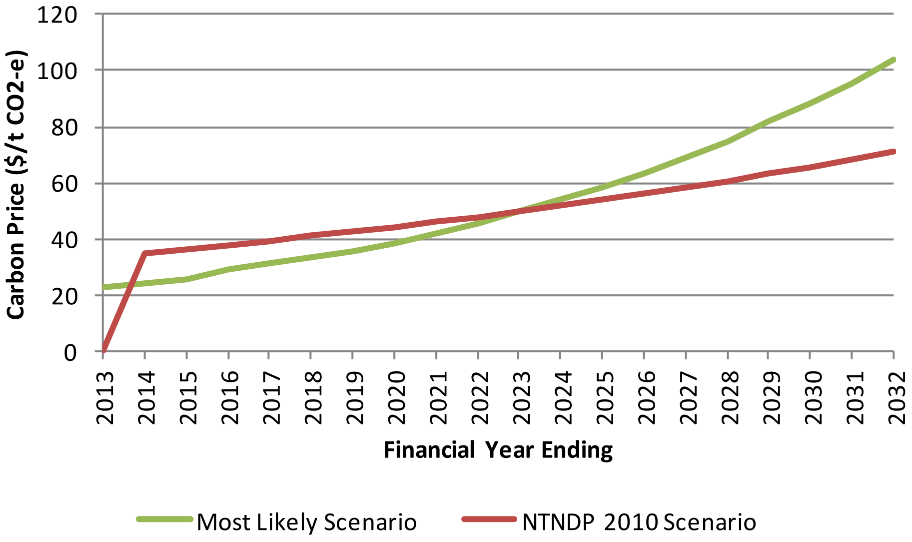


Figure 9-7 NTNDP 2010 Scenario – Gas Costs for New CCGT ($/GJ)



A.3 Carbon Price Trajectory

Figure 9-8 Carbon Price Trajectory ($/t CO2-e)



Appendix B The TFTR Methodology

This appendix details the TFTR Model methodology as understood. While not explicitly included in the modelling, an appreciation of the arrangements was considered necessary for a proper interpretation of results.

The TFTR and SACP methodology are very close, the only difference being the method for the allocation of financial access rights.

Both models entail the calculation of Constraint Support Prices (CSP) and Constraint Support Contracts and thus both are also referred to as the CSP/CSC mechanism.

The CSP/CSC mechanism adjusts the settlements of each generator impacted by a binding transmission constraint where their generation level appears on the LHS of that constraint. The calculation is done over all transmission constraints included in the scheme.

The steps undertaken to apply the NCFA model for each 5 minute dispatch period were as follows:

Step 1 – Calculate Pseudo Nodal Price

- Identify generators "G" that have terms in the LHS on binding constraints;
- For each of these generators, calculate the local marginal price. This establishes a Pseudo Nodal Price or PNP that is used by that generator in settlements. The calculation of this for generator G is as follows noting PNP must fall within the NEM price floor and cap:

  $PNP_G = RRP_G – \sum (Coefficient_{Gk} \text{ x } CSP_{Gk})$ min = -1,000, max = 12,500.

  (Summation is over all constraints: k is the particular constraint of interest and K is the set of all constraints in the NEM)

  The terms are:

  – PNP_G is the local marginal price applying to a particular generator G;
  – RRP_G is the regional reference price of the region in which G is located;
  – $Coefficient_{Gk}$ is the coefficient of generator G in the binding constraint equation k. The coefficient is a measure of the impact generators G's dispatch has on energy flows across the constraint k (noting that this can have a positive or negative sign);
  – CSP_{Gk} is the marginal value of a particular constraint k to which G is exposed (in other words, the reduction in total dispatch costs achieved by relieving the constraint k by 1 MW). If the constraint is not binding than $CSP_{Gk} = 0$

Note: In the analysis we have not considered or included Marginal Loss Factors (MLFs) which account for losses. If these were to be included then the RRP_G term would be multiplied by the locational MLF.

Step 2 – Calculate Spot Revenues based on the PNP

- For each Generator G calculate its spot revenue for generation based on the Pseudo Nodal Price or $PNP_{G:}$

  $Revenue_G = PNP_G \times Gen_G$

  where Gen_G is the output (MWh) of Generator G in that 5 minute dispatch period.

  (Here we observe that if G is not associated with any binding constraints then $PNP_G = RRP_{G.)}$

Step 3 – Allocation of Hedging Cover (Financial Capacity Right) Allocated to Generator G

The TFTR model has CSC allocated to generators (and interconnectors) via pre-determined agreements with the appropriate TNSP. The general principles of allocation are on a "first in basis. This can be thought of as a quantity of the available rights or as a proportion of the residues available for allocation.

The quantity is termed $Q_{Gk.}$

(This is different to the SACP Model where the proportion of residue available for allocation is determined each 5 minute dispatch period based on each generators and interconnectors availability.)

Step 4 – Calculate the Residue allocated to each Generator G

This is simply the capacity right (or CSC capacity) multiplied by difference in prices between the RRP and the PNP. For Generator G and constraint k the Constraint Support Contract payment to generator G associated with constraint k is as follows:

$$CSC_{Gk} = Q_{Gk} \times (RRP_G – PNP_G)$$

In essence a CSC represents a right to a proportion of the residue of constraint k that collects between two pricing nodes.

Step 5 – Total Settlements

The total settlements for Generator G are then the sum of:

- Spot revenue at the local node: $PNP_G \times Gen_G$
- Constraint Support Contract payment: $CSC_{Gk} = Q_{Gk} \times (RRP_G – PNP_G)$ over all constraints K.

We note that:

- Spot revenue is a function of actual generation while the CSC payment is a function of generator availability only;
- The quantity of CSC allocated to interconnectors impacts generators. The sensitivity of the approach used for interconnectors is identified in the modelling undertaken.

Appendix C Most Likely Scenario Results

The appendix presents the detailed modelling results of the Most Likely Scenario.

The following are presented:

- Transmission upgrades that occurred and timing;
- NPV of total investment and operating costs;
- The sum of cumulative marginal costs for each year;
- Number of binding constraints and sum of total hours constraints were binding;
- Difference in new entry capacity (MW) by region for each of the Status Quo cases compared to the TFTR case;
- Difference in total generation (GWh) by region for each of the Status Quo cases compared to the TFTR case.

9-9 Sum of Cumulative Marginal Costs ($M/MW)

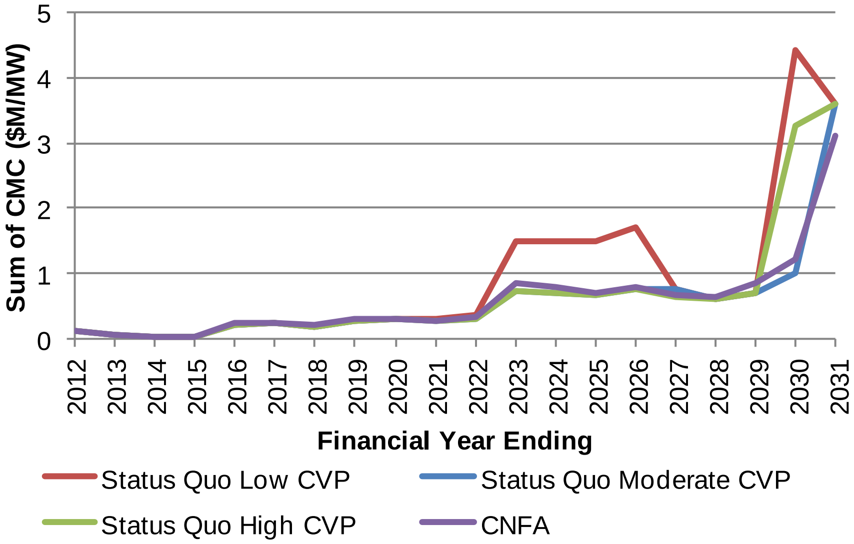


Figure 9-10 No. of Binding Constraints

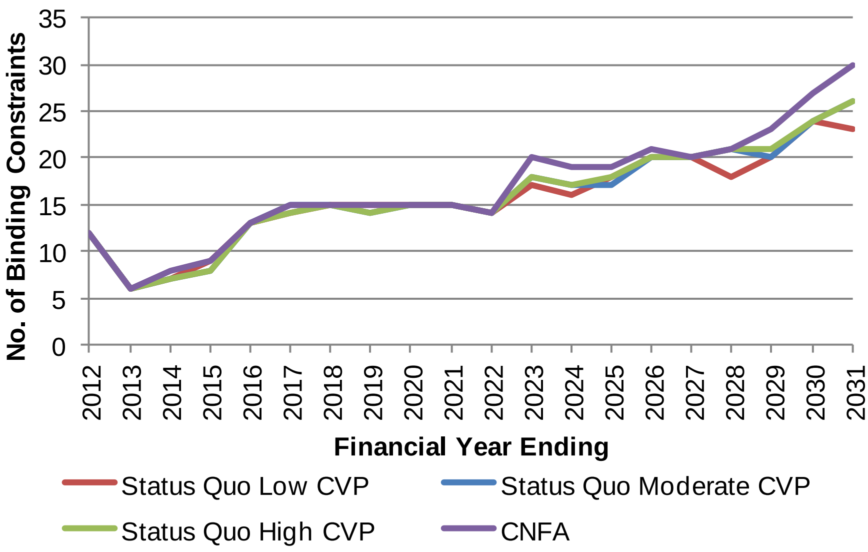
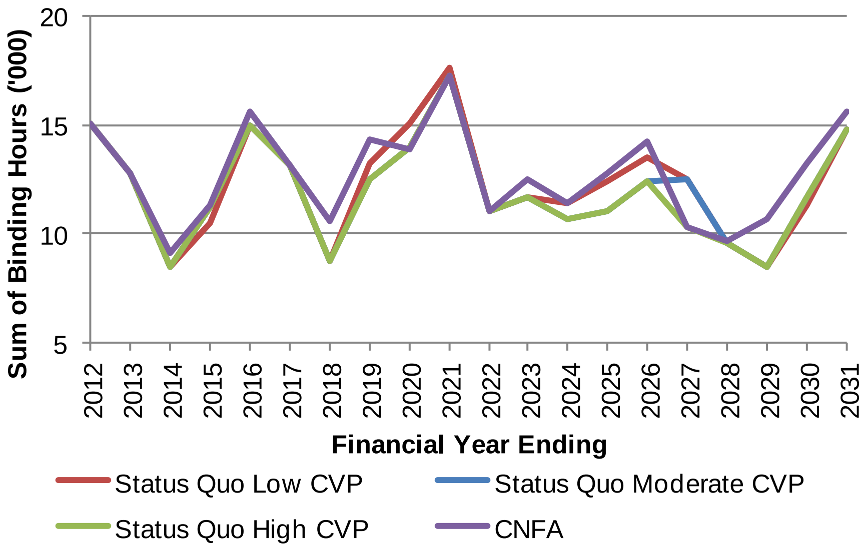
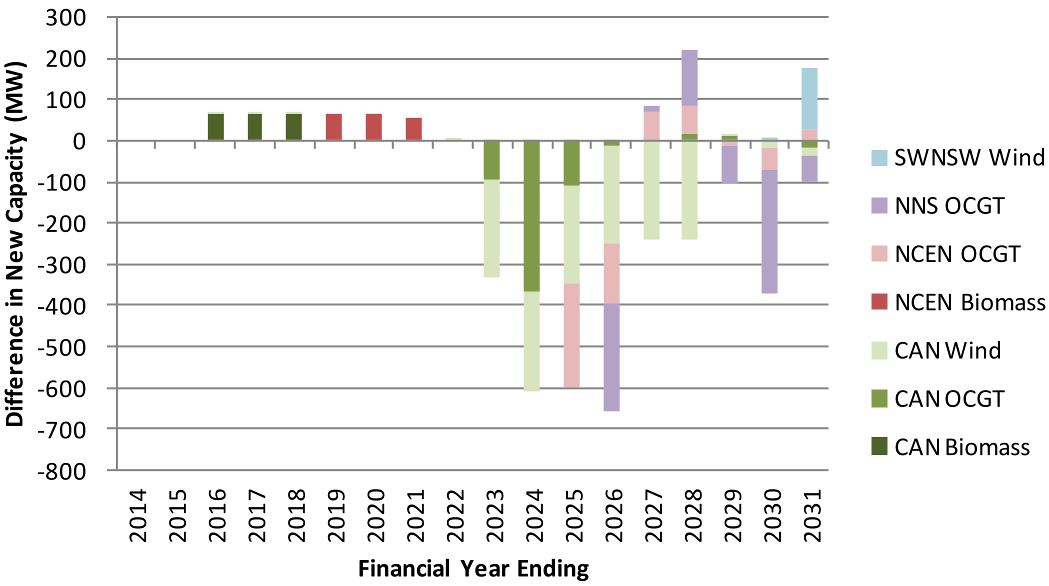


Figure 9-11 Sum of Binding Hours (Thousands)



Status Quo Low Case compared to TFTR case

Figure 9-12 Difference in New Capacity – NSW [Status Quo Low CVP – TFTR] (MW Cumulative)



Note: There is effectively no capacity reserve requirement in NSW due to negative Minimum Reserve Level (MRL).

Figure 9-13 Difference in New Capacity – Qld [Status Quo Low CVP – TFTR] (MW Cumulative)

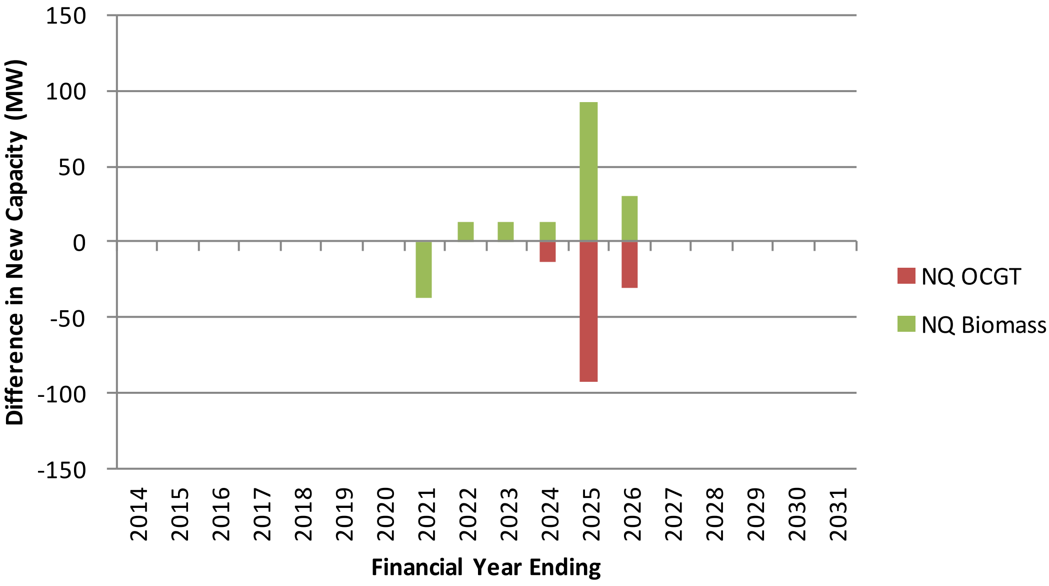


Figure 9-14 Difference in New Capacity – SA [Status Quo Low CVP – TFTR] (MW Cumulative)

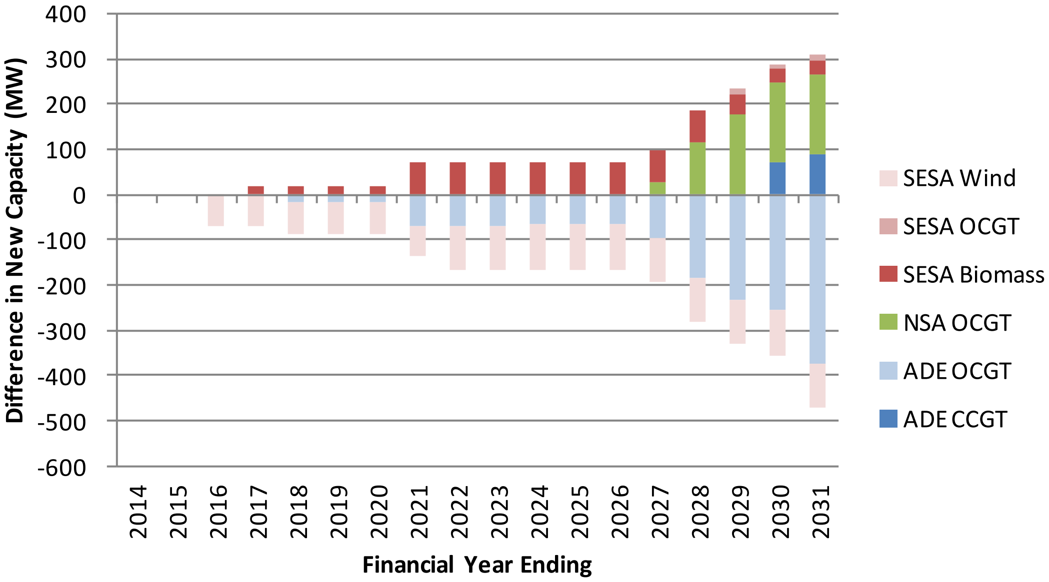


Figure 9-15 Difference in New Capacity – Vic & Tas [Status Quo Low CVP – TFTR] (MW Cumulative)

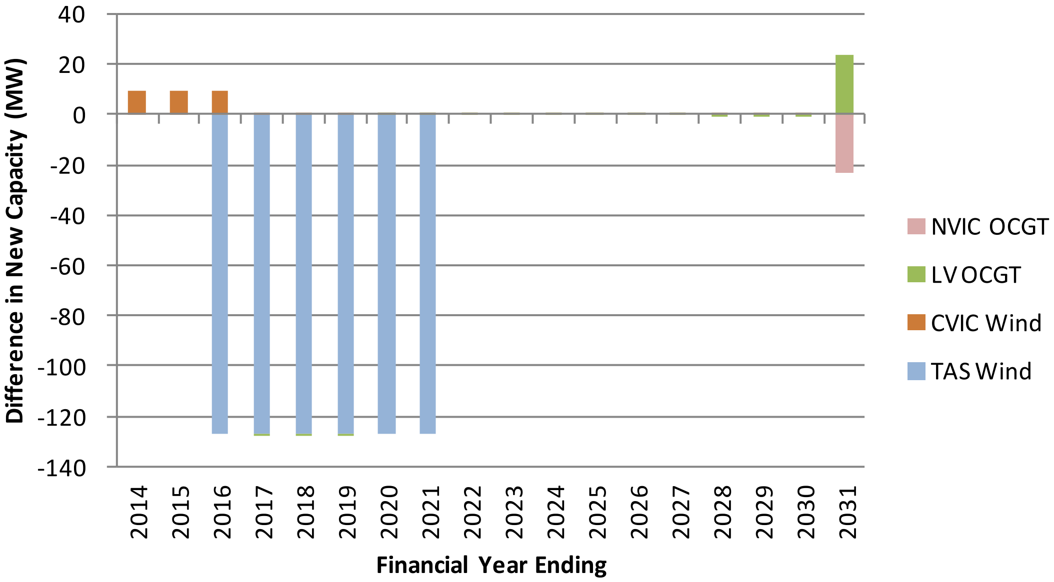


Figure 9-16 Difference in Generation – NSW [Status Quo Low CVP – TFTR] (GWh)

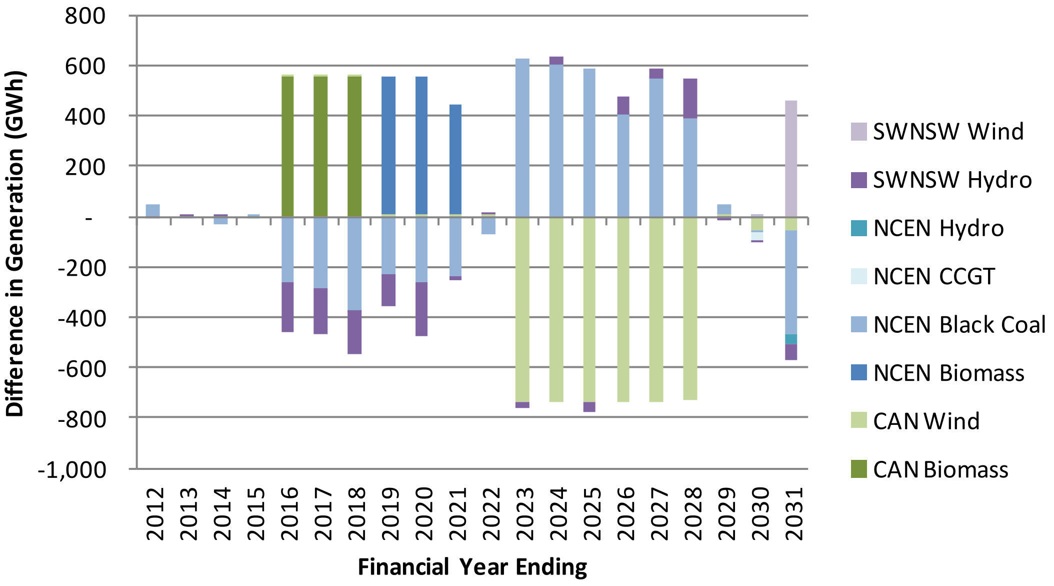


Figure 9-17 Difference in Generation – Qld [Status Quo Low CVP – TFTR] (GWh)

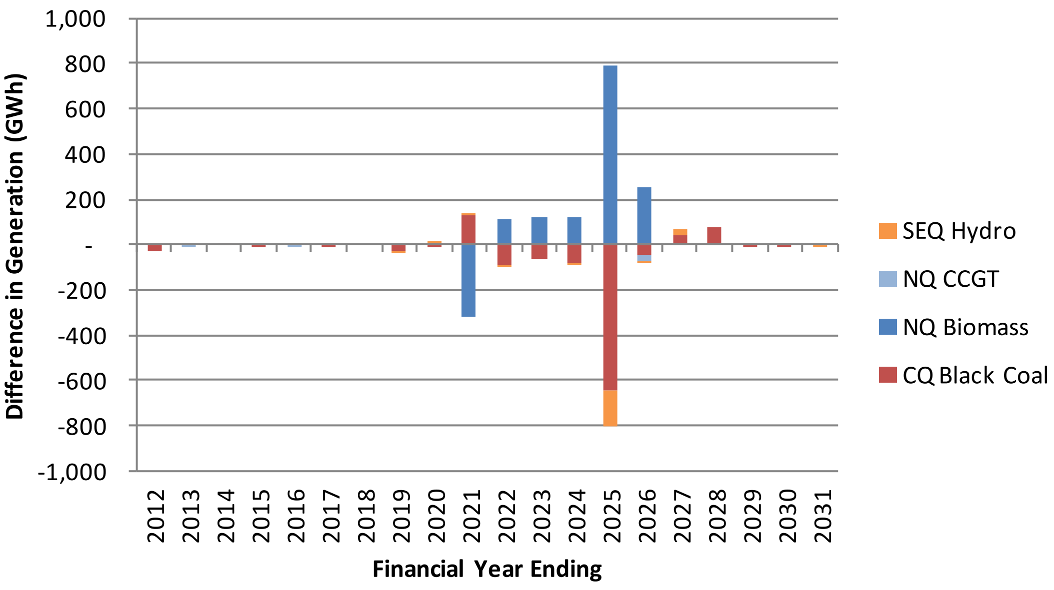


Figure 9-18 Difference in Generation – SA [Status Quo Low CVP – TFTR] (GWh)

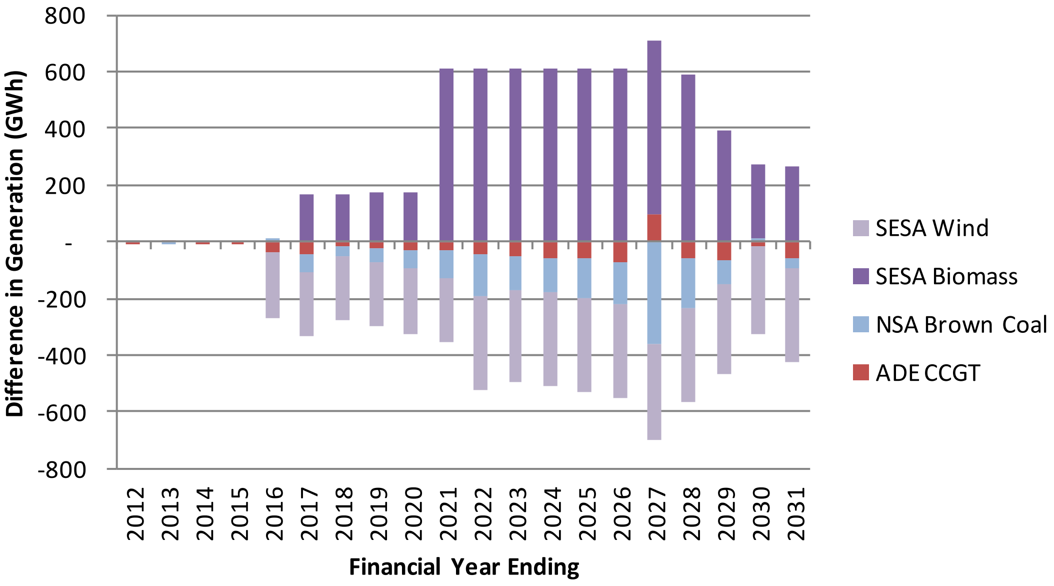
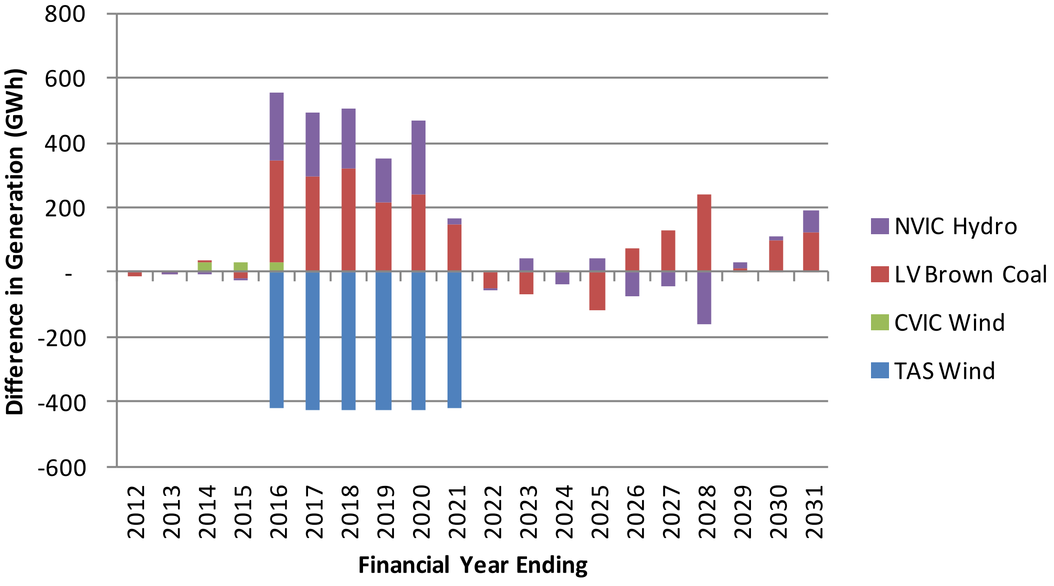


Figure 9-19 Difference in Generation – Vic & Tas [Status Quo Low CVP – TFTR] (GWh)



Moderate Case compared to TFTR case

Figure 9-20 Difference in New Capacity – NSW [Status Quo Moderate CVP – TFTR] (MW Cumulative)

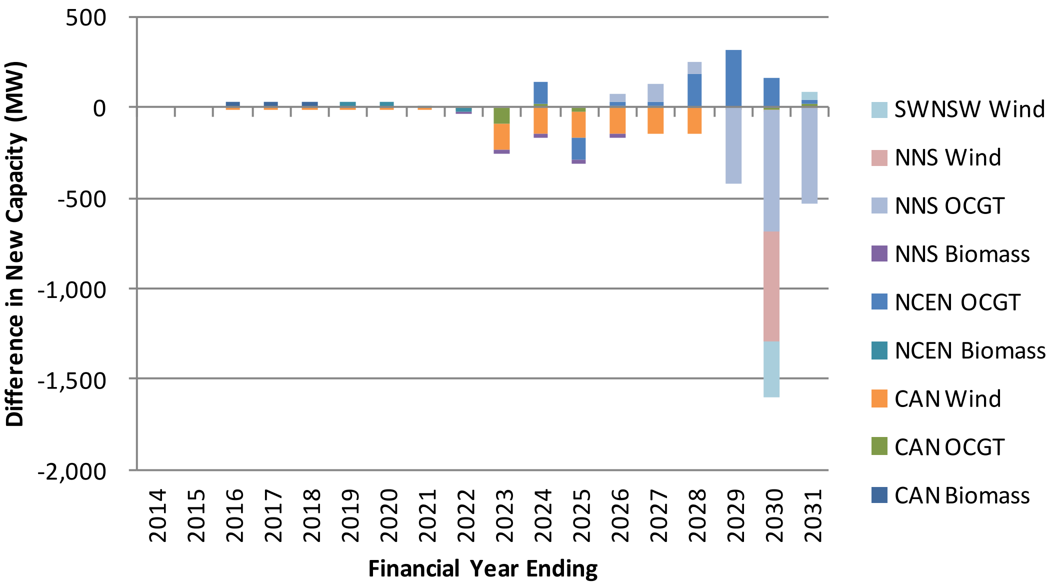


Figure 9-21 Difference in New Capacity – Qld [Status Quo Moderate CVP – TFTR] (MW Cumulative)

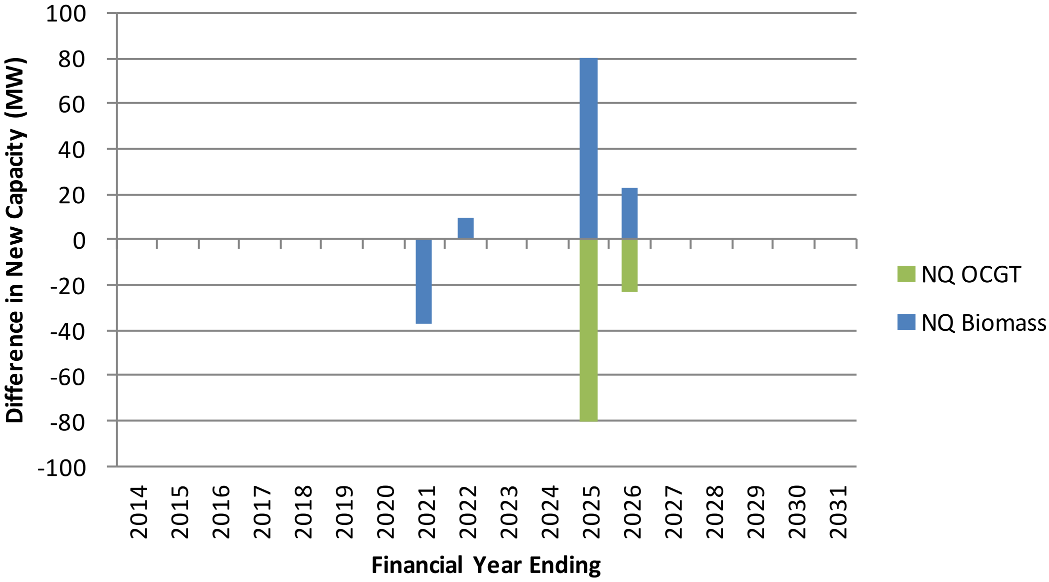


Figure 9-22 Difference in New Capacity – SA [Status Quo Moderate CVP – TFTR] (MW Cumulative)

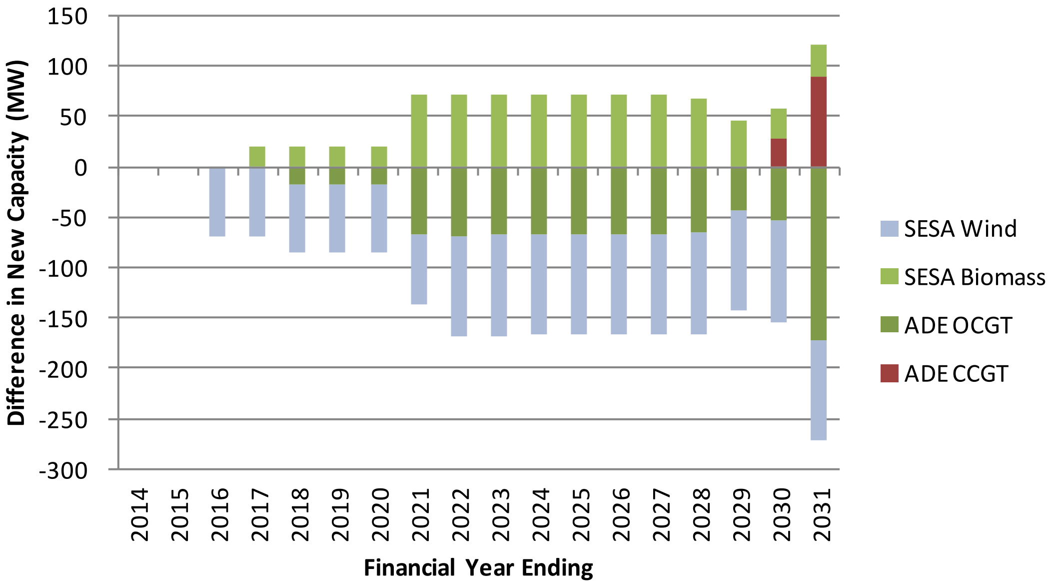


Figure 9-23 Difference in New Capacity – Vic & Tas [Status Quo Moderate CVP – TFTR] (MW Cumulative)

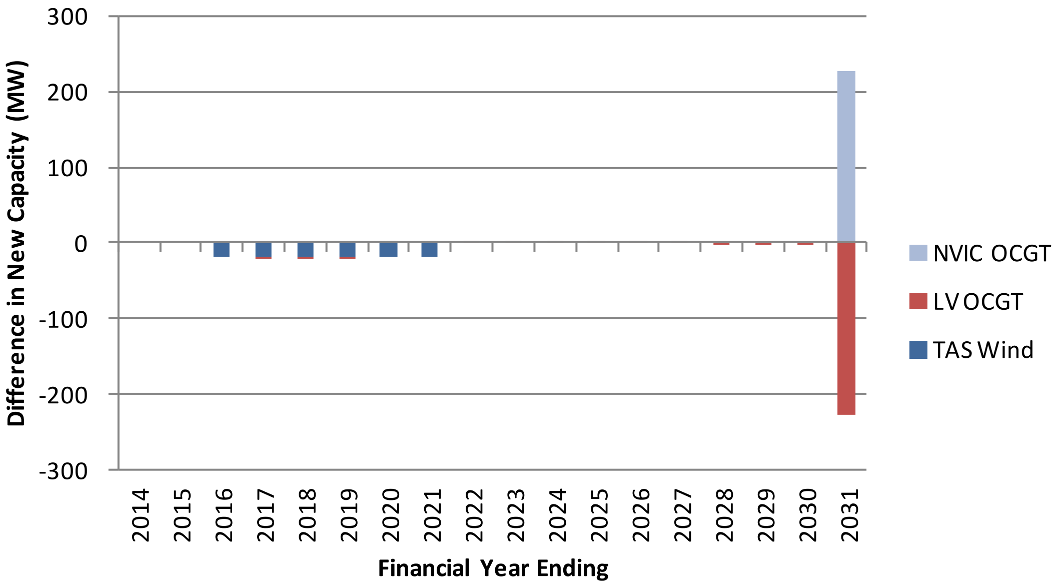


Figure 9-24 Difference in Generation – NSW [Status Quo Moderate CVP – TFTR] (GWh)

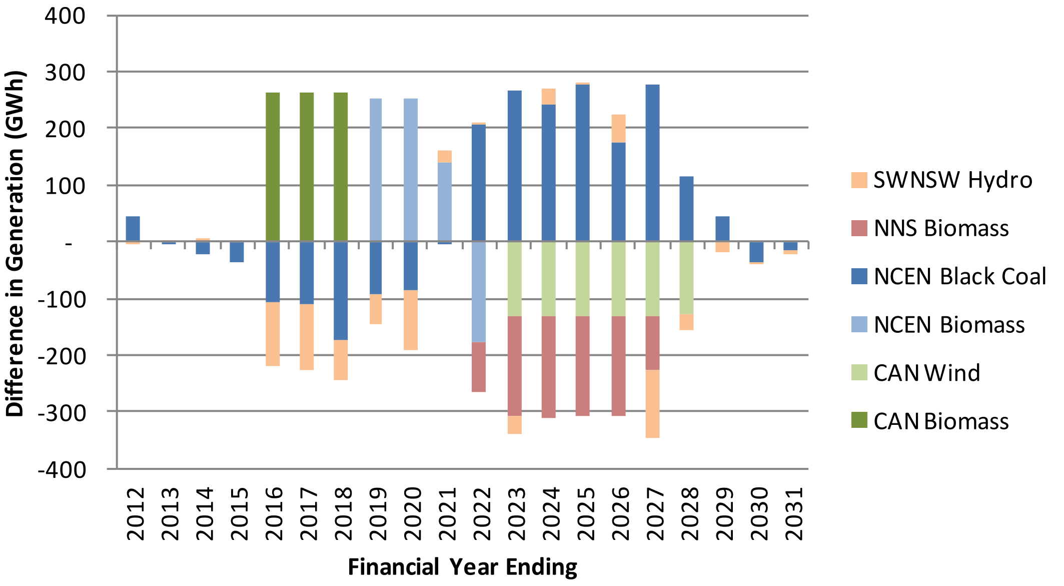


Figure 9-25 Difference in Generation – Qld [Status Quo Moderate CVP – TFTR] (GWh)

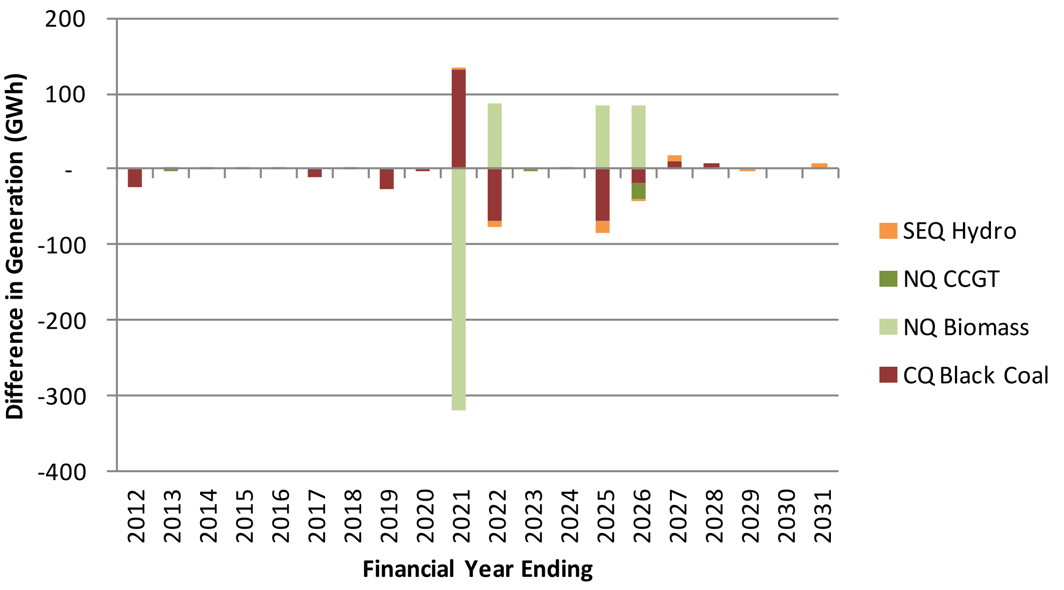


Figure 9-26 Difference in Generation – SA [Status Quo Moderate CVP – TFTR] (GWh)

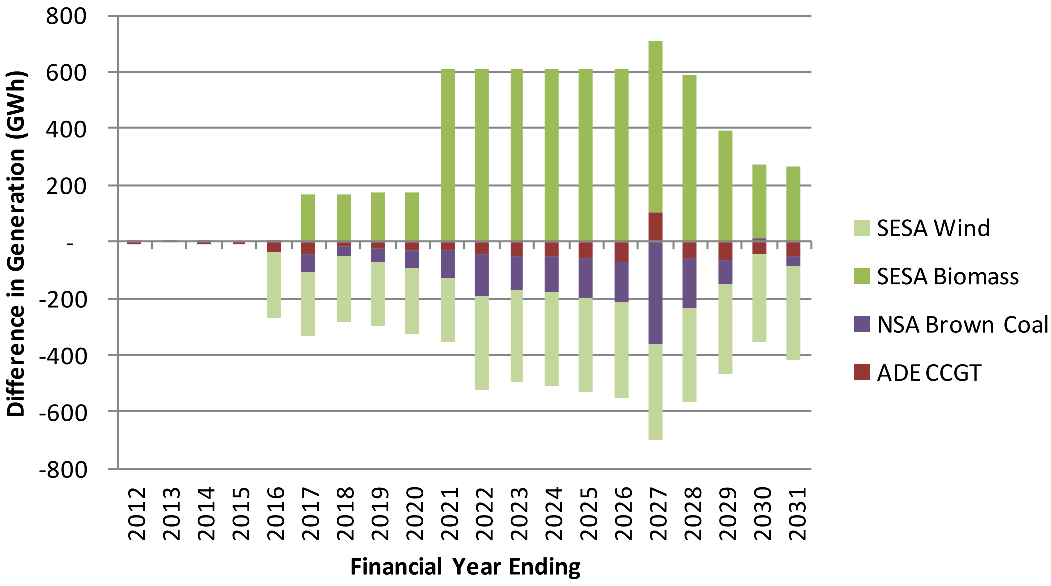
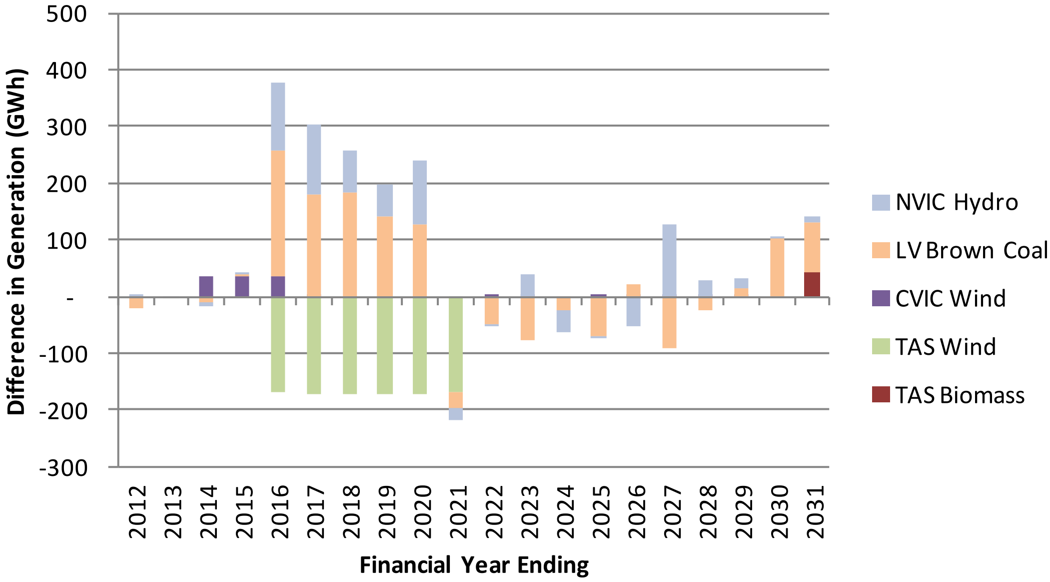


Figure 9-27 Difference in Generation – Vic & Tas [Status Quo Moderate CVP – TFTR] (GWh)



High Case compared to TFTR case

Figure 9-28 Difference in New Capacity – NSW [Status Quo High CVP – TFTR] (MW Cumulative)

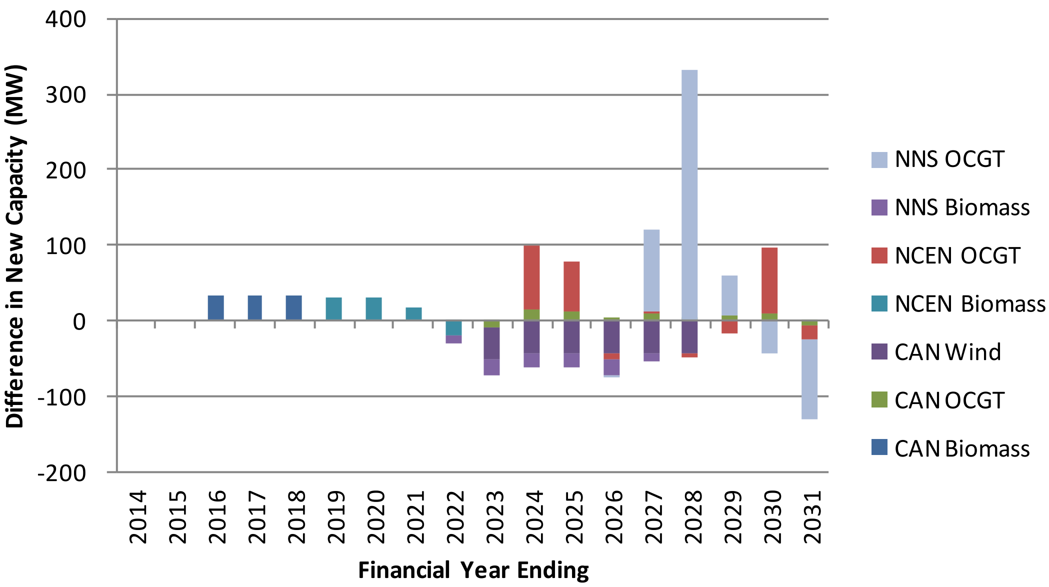


Figure 9-29 Difference in New Capacity – SA [Status Quo High CVP – TFTR] (MW Cumulative)

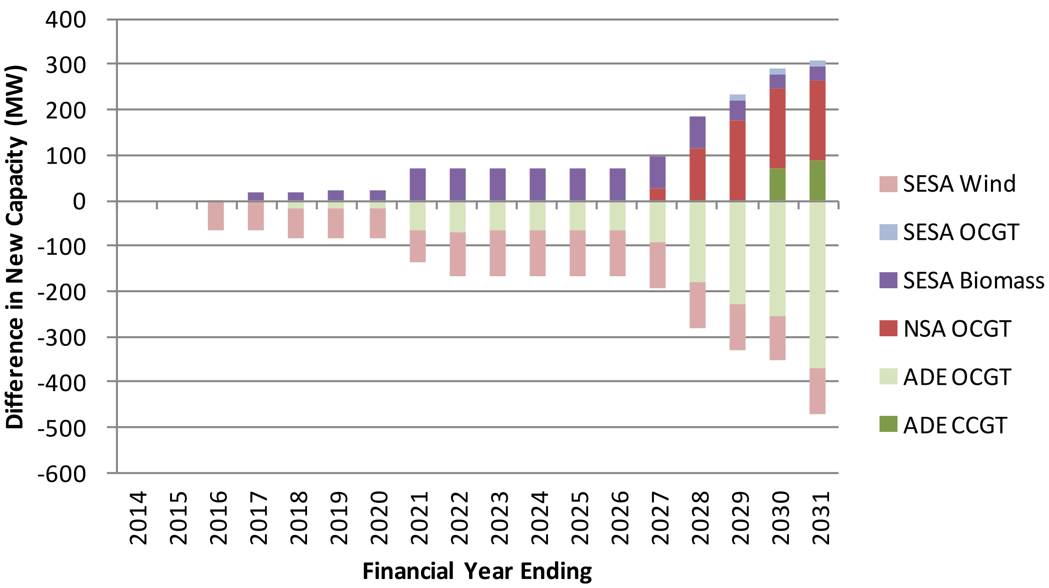


Figure 9-30 Difference in New Capacity – Vic & Tas [Status Quo High CVP – TFTR] (MW Cumulative)

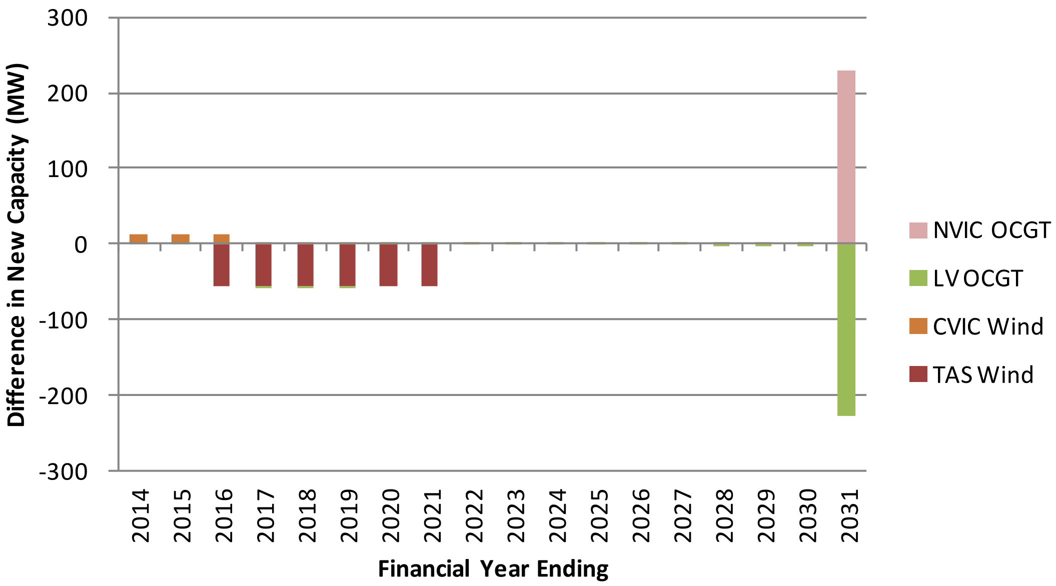


Figure 9-31 Difference in Generation – NSW [Status Quo High CVP – TFTR] (GWh)

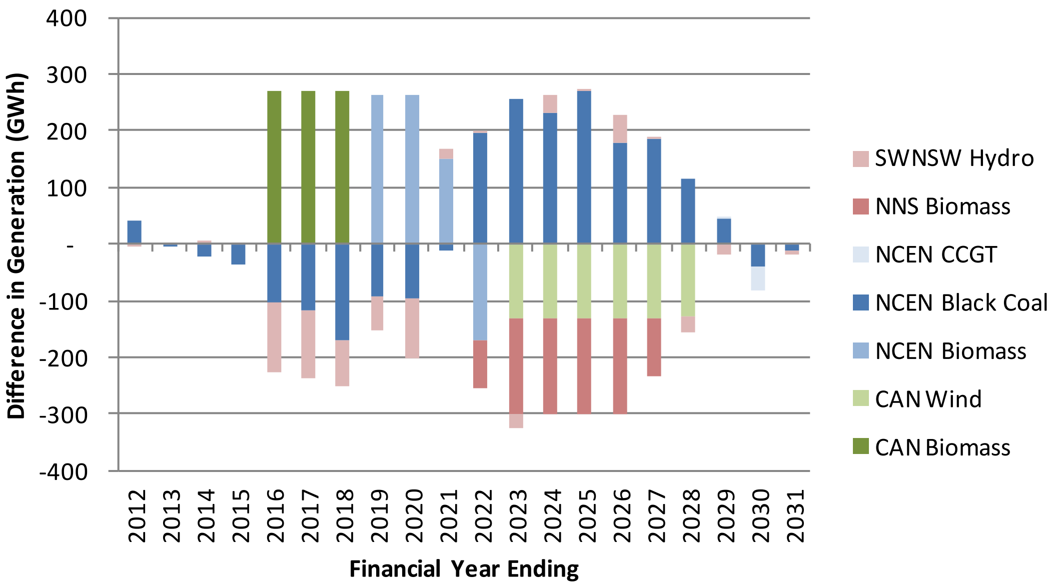


Figure 9-32 Difference in Generation – Qld [Status Quo High CVP – TFTR] (GWh)

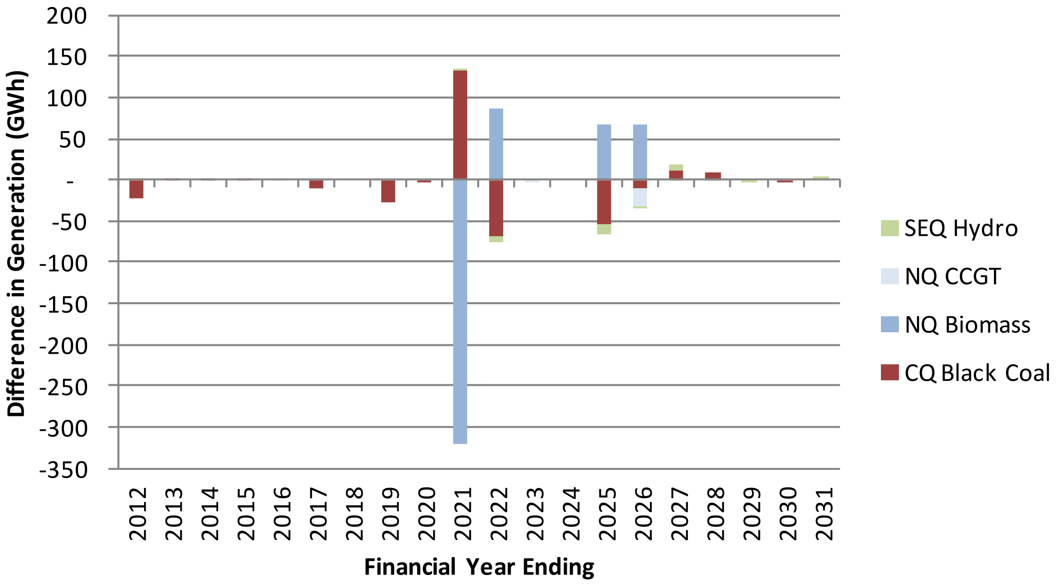


Figure 9-33 Difference in Generation – SA [Status Quo High CVP – TFTR] (GWh)

Figure 9-34 Difference in Generation – Vic & Tas [Status Quo High CVP – TFTR] (GWh)

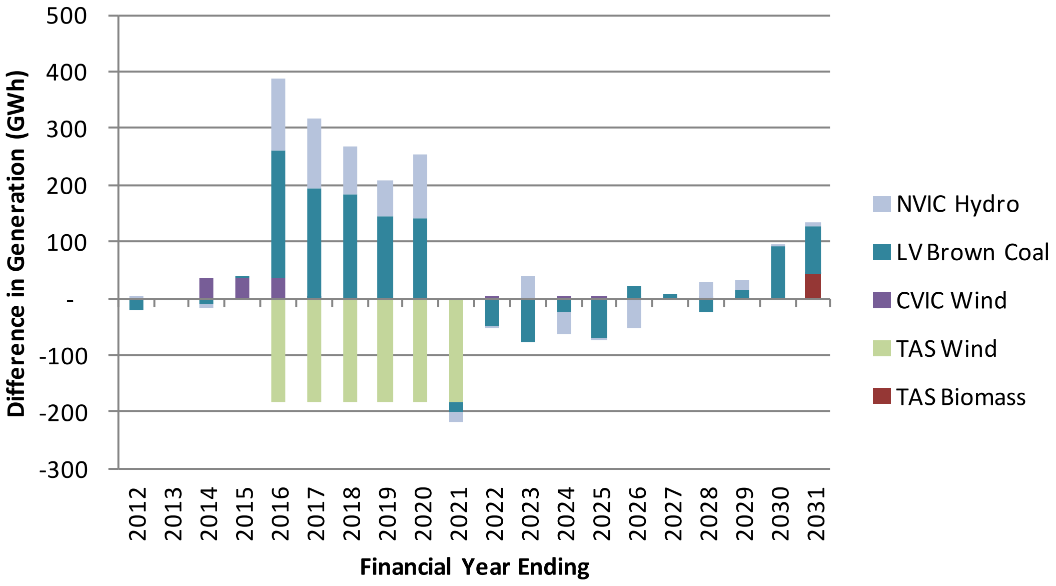


Table 9-3 New Capacity (MW Cumulative) – Most Likely Scenario – Status Quo Low Case

Zone	Type	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
CAN	Biomass	0	0	69	69	69	100	100	100	100	100	100	100	100	100	100	100	100	100
CAN	OCGT	0	0	0	0	0	0	0	0	0	0	0	300	425	461	498	501	506	506
CAN	Wind	0	0	883	883	883	883	883	883	883	883	883	883	883	883	883	1,267	1,267	1,267
NCEN	Biomass	0	0	0	0	0	67	98	98	100	100	100	100	100	100	100	100	100	100
NCEN	OCGT	0	0	0	0	0	0	0	0	0	0	0	0	300	567	857	1,081	1,200	1,424
NCEN	Wind	0	0	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
NNS	Biomass	0	0	0	0	0	0	0	0	10	100	100	100	100	100	100	100	100	100
NNS	OCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	445	600	856	900	1,200
NNS	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	602	603
SWNSW	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	613	794
NQ	Biomass	0	0	0	0	0	0	0	6	93	104	204	293	330	400	400	400	400	400
NQ	OCGT	0	0	0	0	0	0	0	0	0	0	150	382	676	900	900	900	900	900
SEQ	OCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	45	388	742	1,106	1,481
SWQ	Wind	0	489	489	489	489	489	489	489	489	489	489	489	489	490	490	490	490	490
ADE	CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	82	200
ADE	OCGT	0	0	0	0	0	0	0	0	63	139	189	278	354	400	400	400	400	400
NSA	OCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	27	117	176	176	176
NSA	Wind	829	829	829	988	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,722	1,722	1,722	1,729
SESA	Biomass	0	0	0	19	119	121	191	285	285	285	285	285	285	285	300	300	300	300
SESA	OCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12	12	12
SESA	Wind	0	0	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900
TAS	Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	44
TAS	Wind	0	0	713	713	713	713	713	713	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
CVIC	OCGT	0	0	0	0	0	0	403	599	824	1,102	1,275	1,535	1,800	1,800	1,800	1,800	1,800	1,800
CVIC	Wind	398	398	398	952	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,453	1,453	1,457
LV	OCGT	0	0	0	163	492	1,001	1,208	1,208	1,208	1,208	1,208	1,208	1,208	1,480	1,774	2,111	2,319	2,652
MEL	Wind	0	0	0	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000

Table 9-4 Generation by Zone (GWh) – Most Likely Scenario – Status Quo Low Case

Region	Zone	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
NSW	CAN	1,133	1,139	1,134	1,134	4,395	4,415	4,416	4,718	4,691	4,691	4,662	4,678	4,718	4,699	4,691	4,687	4,674	5,858	5,908	5,871
NSW	NCEN	62,719	60,764	61,551	62,498	59,425	63,311	63,660	65,614	66,929	71,203	72,580	73,685	75,577	77,600	82,286	82,490	84,103	85,159	84,698	86,908
NSW	NNS	0	0	0	0	0	0	0	0	0	0	89	858	858	858	858	859	860	860	2,704	2,705
NSW	SWNSW	1,944	3,715	3,847	2,859	3,694	2,156	3,192	2,966	2,969	494	182	219	203	323	747	1,382	1,461	1,482	3,147	3,637
Qld	CQ	26,393	26,036	27,071	25,091	26,097	29,140	31,108	31,414	34,200	34,713	35,210	35,740	35,831	36,645	34,486	35,300	36,399	37,881	38,278	38,914
Qld	NQ	621	643	629	629	1,287	2,058	2,058	2,656	629	683	1,430	1,520	2,379	3,129	3,479	4,196	4,231	4,233	4,274	4,308
Qld	SEQ	1,057	1,277	1,976	2,207	1	5	7	7	280	292	319	357	362	574	433	638	1,080	1,640	1,750	1,748
Qld	SWQ	29,805	29,807	29,807	32,699	34,303	31,307	30,170	30,173	30,171	30,174	30,168	30,178	30,173	30,176	30,179	30,180	30,268	30,338	30,490	30,738
SA	ADE	779	2,706	879	810	617	558	394	404	436	485	549	593	643	713	757	842	803	901	1,046	1,188
SA	NSA	8,558	7,569	10,023	10,138	9,268	9,410	10,294	10,209	10,269	10,415	10,501	10,682	10,892	11,076	11,250	11,406	11,721	12,116	12,450	12,728
SA	SESA	1,200	1,202	1,199	1,203	4,183	4,360	5,222	5,239	5,842	6,656	6,617	6,634	6,642	6,630	6,642	6,660	6,752	6,763	6,769	6,771
Tas	TAS	9,134	10,532	9,614	9,615	11,947	11,998	11,996	11,994	11,975	11,993	12,908	12,958	12,933	12,948	12,948	12,954	12,895	12,942	12,947	12,876
Vic	CVIC	2,014	2,018	3,270	3,255	3,240	4,933	6,501	6,504	6,477	6,484	6,457	6,457	6,478	6,468	6,480	6,497	6,466	6,474	6,497	6,493
Vic	LV	53,899	50,069	49,073	47,383	42,828	38,135	35,723	35,487	34,948	31,769	30,872	30,890	30,771	31,339	32,183	34,205	34,481	34,887	35,040	35,952
Vic	MEL	620	635	635	637	635	2,169	3,697	3,708	3,709	3,715	3,681	3,696	3,705	3,693	3,705	3,724	3,685	3,692	3,705	3,708
Vic	NVIC	6,143	5,574	4,655	5,668	4,789	6,405	5,320	5,556	5,551	8,140	8,485	8,438	8,450	8,327	7,843	7,248	7,132	7,120	7,349	6,996

Table 9-5 New Capacity (MW Cumulative) – Most Likely Scenario – Status Quo Moderate Case

Zone	Type	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
CAN	Biomass	0	0	34	34	34	100	100	100	100	100	100	100	100	100	100	100	100	100
CAN	OCGT	0	0	0	0	0	0	0	0	0	78	381	419	440	464	481	498	509	519
CAN	Wind	0	0	880	880	880	880	880	880	880	1,080	1,080	1,080	1,080	1,080	1,080	1,264	1,283	1,283
NCEN	Biomass	0	0	0	0	0	33	63	63	79	100	100	100	100	100	100	100	100	100
NCEN	OCGT	0	0	0	0	0	0	0	0	0	0	35	298	435	511	784	1,077	1,266	1,381
NCEN	Wind	0	0	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
NNS	Biomass	0	0	0	0	0	0	0	0	0	79	79	79	79	89	100	100	100	100
NNS	OCGT	0	0	0	0	0	0	0	0	0	0	0	0	301	433	797	938	1,154	1,154
NNS	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	602	603
SWNSW	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	613	643
NQ	Biomass	0	0	0	0	0	0	0	6	90	90	190	210	310	400	400	400	400	400
NQ	OCGT	0	0	0	0	0	0	0	0	0	0	164	465	697	900	900	900	900	900
SEQ	OCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	45	388	742	1,106	1,481
SWQ	Wind	0	489	489	489	489	489	489	489	489	489	489	489	489	490	490	490	490	490
ADE	CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	39	200
ADE	OCGT	0	0	0	0	0	0	0	0	63	139	189	278	354	427	517	588	600	600
NSA	Wind	829	829	829	988	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,722	1,722	1,722	1,729
SESA	Biomass	0	0	0	19	119	121	191	285	285	285	285	285	285	285	300	300	300	300
SESA	Wind	0	0	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900
TAS	Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	51
TAS	Wind	0	0	789	789	789	789	789	789	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
CVIC	OCGT	0	0	0	0	0	0	403	599	824	1,102	1,275	1,535	1,800	1,800	1,800	1,800	1,800	1,800
CVIC	Wind	399	399	399	952	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,453	1,453	1,457
LV	OCGT	0	0	0	163	492	1,001	1,208	1,208	1,208	1,208	1,208	1,208	1,208	1,480	1,774	2,111	2,319	2,400
MEL	Wind	0	0	0	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
NVIC	OCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	252

Table 9-6 Generation by Zone (GWh) – Most Likely Scenario – Status Quo Moderate Case

Region	Zone	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
NSW	CAN	1,133	1,139	1,134	1,134	4,090	4,112	4,111	4,711	4,684	4,683	4,655	5,283	5,328	5,303	5,295	5,294	5,274	5,851	5,960	5,923
NSW	NCEN	62,713	60,764	61,557	62,461	59,581	63,485	63,858	65,456	66,806	71,138	72,681	73,319	75,214	77,288	82,057	82,221	83,823	85,166	84,687	87,337
NSW	NNS	0	0	0	0	0	0	0	0	0	0	0	679	679	679	680	764	860	861	2,705	2,705
NSW	SWNSW	1,949	3,714	3,848	2,859	3,780	2,225	3,298	3,038	3,079	531	182	221	203	365	724	1,219	1,280	1,482	3,149	3,229
Qld	CQ	26,401	26,035	27,071	25,102	26,097	29,142	31,108	31,419	34,200	34,713	35,233	35,808	35,911	37,222	34,518	35,265	36,334	37,881	38,278	38,914
Qld	NQ	621	643	629	629	1,287	2,058	2,058	2,656	629	683	1,401	1,402	2,261	2,419	3,306	4,196	4,231	4,233	4,273	4,308
Qld	SEQ	1,057	1,277	1,976	2,207	2	5	7	11	264	292	321	357	372	720	440	625	1,080	1,639	1,750	1,764
Qld	SWQ	29,805	29,807	29,808	32,699	34,303	31,307	30,170	30,173	30,171	30,174	30,169	30,177	30,173	30,177	30,179	30,180	30,268	30,338	30,490	30,742
SA	ADE	780	2,706	879	810	617	559	394	404	437	487	549	593	644	713	759	845	804	902	1,020	1,198
SA	NSA	8,558	7,569	10,023	10,138	9,267	9,410	10,292	10,207	10,269	10,413	10,501	10,681	10,891	11,075	11,249	11,405	11,717	12,115	12,450	12,726
SA	SESA	1,200	1,202	1,199	1,203	4,183	4,360	5,222	5,239	5,842	6,656	6,617	6,634	6,642	6,630	6,642	6,660	6,752	6,763	6,769	6,771
Tas	TAS	9,134	10,532	9,614	9,615	12,197	12,252	12,248	12,247	12,228	12,246	12,908	12,957	12,933	12,948	12,947	12,954	12,895	12,942	12,947	12,930
Vic	CVIC	2,014	2,018	3,275	3,260	3,245	4,933	6,501	6,504	6,477	6,484	6,457	6,457	6,477	6,468	6,480	6,497	6,466	6,474	6,497	6,493
Vic	LV	53,888	50,069	49,061	47,406	42,736	38,019	35,587	35,409	34,834	31,597	30,873	30,879	30,742	31,384	32,130	33,986	34,220	34,887	35,042	35,913
Vic	MEL	620	635	635	637	635	2,169	3,697	3,708	3,709	3,715	3,681	3,696	3,705	3,693	3,705	3,723	3,684	3,693	3,705	3,707
Vic	NVIC	6,138	5,574	4,653	5,668	4,699	6,332	5,209	5,481	5,436	8,101	8,485	8,436	8,451	8,283	7,867	7,419	7,321	7,120	7,341	6,942

Table 9-7 New Capacity (MW Cumulative) – Most Likely Scenario – Status Quo High Case

Zone	Type	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
CAN	Biomass	0	0	36	36	36	100	100	100	100	100	100	100	100	100	100	100	100	100
CAN	OCGT	0	0	0	0	0	0	0	0	0	82	383	421	440	466	482	497	512	519
CAN	Wind	0	0	880	880	880	880	880	880	880	1,080	1,080	1,080	1,080	1,080	1,080	1,264	1,283	1,283
NCEN	Biomass	0	0	0	0	0	34	64	64	80	100	100	100	100	100	100	100	100	100
NCEN	OCGT	0	0	0	0	0	0	0	0	0	0	85	318	434	504	780	1,077	1,343	1,381
NCEN	Wind	0	0	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
NNS	Biomass	0	0	0	0	0	0	0	0	0	80	80	80	80	88	100	100	100	100
NNS	OCGT	0	0	0	0	0	0	0	0	0	0	0	0	260	536	798	998	1,158	1,158
NNS	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	602	603
SWNSW	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	613	643
NQ	Biomass	0	0	0	0	0	0	0	6	90	90	190	208	308	400	400	400	400	400
NQ	OCGT	0	0	0	0	0	0	0	0	0	0	164	467	699	900	900	900	900	900
SEQ	OCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	45	388	742	1,106	1,481
SWQ	Wind	0	489	489	489	489	489	489	489	489	489	489	489	489	490	490	490	490	490
ADE	CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	84	200
ADE	OCGT	0	0	0	0	0	0	0	0	63	139	189	278	354	400	400	400	400	400
NSA	OCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	27	117	176	176	176
NSA	Wind	829	829	829	988	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,722	1,722	1,722	1,729
SESA	Biomass	0	0	0	19	119	121	191	285	285	285	285	285	285	285	300	300	300	300
SESA	Wind	0	0	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900
TAS	Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	51
TAS	Wind	0	0	785	785	785	785	785	785	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
CVIC	OCGT	0	0	0	0	0	0	403	599	824	1,102	1,275	1,535	1,800	1,800	1,800	1,800	1,800	1,800
CVIC	Wind	399	399	399	952	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,453	1,453	1,457
LV	OCGT	0	0	0	163	492	1,001	1,208	1,208	1,208	1,208	1,208	1,208	1,208	1,480	1,774	2,111	2,319	2,400
MEL	Wind	0	0	0	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
NVIC	OCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	252

Table 9-8 Generation by Zone (GWh) – Most Likely Scenario – Status Quo High Case

Region	Zone	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
NSW	CAN	1,133	1,139	1,134	1,134	4,100	4,121	4,121	4,711	4,684	4,683	4,655	5,283	5,328	5,303	5,295	5,294	5,274	5,851	5,960	5,923
NSW	NCEN	62,712	60,764	61,557	62,459	59,583	63,475	63,861	65,465	66,807	71,139	72,682	73,310	75,206	77,281	82,059	82,131	83,823	85,166	84,661	87,340
NSW	NNS	0	0	0	0	0	0	0	0	0	0	0	688	688	688	689	756	860	861	2,705	2,705
NSW	SWNSW	1,948	3,715	3,848	2,859	3,768	2,225	3,286	3,031	3,079	530	182	222	202	366	724	1,342	1,281	1,482	3,149	3,231
Qld	CQ	26,402	26,036	27,071	25,102	26,097	29,143	31,108	31,419	34,200	34,713	35,233	35,808	35,911	37,236	34,526	35,266	36,334	37,881	38,278	38,914
Qld	NQ	621	643	629	629	1,287	2,058	2,058	2,656	629	683	1,401	1,402	2,260	2,401	3,289	4,196	4,231	4,233	4,273	4,308
Qld	SEQ	1,057	1,277	1,976	2,207	2	5	7	11	264	292	321	357	372	724	441	625	1,080	1,639	1,749	1,762
Qld	SWQ	29,805	29,807	29,808	32,699	34,303	31,307	30,170	30,173	30,171	30,174	30,169	30,177	30,173	30,176	30,179	30,180	30,268	30,338	30,490	30,742
SA	ADE	780	2,707	879	810	617	559	394	404	436	487	549	593	644	713	759	686	803	901	1,046	1,196
SA	NSA	8,558	7,569	10,023	10,138	9,267	9,410	10,292	10,207	10,270	10,413	10,501	10,681	10,891	11,075	11,249	11,574	11,718	12,116	12,451	12,728
SA	SESA	1,200	1,202	1,199	1,203	4,183	4,360	5,222	5,239	5,842	6,656	6,617	6,634	6,642	6,630	6,642	6,660	6,752	6,763	6,769	6,771
Tas	TAS	9,134	10,533	9,614	9,615	12,184	12,239	12,235	12,234	12,215	12,233	12,907	12,958	12,933	12,948	12,947	12,954	12,894	12,942	12,947	12,929
Vic	CVIC	2,014	2,018	3,276	3,260	3,246	4,933	6,501	6,504	6,477	6,484	6,457	6,457	6,478	6,468	6,480	6,497	6,466	6,474	6,497	6,493
Vic	LV	53,888	50,068	49,060	47,406	42,735	38,033	35,587	35,413	34,847	31,608	30,873	30,879	30,741	31,385	32,130	34,085	34,220	34,887	35,034	35,910
Vic	MEL	620	635	635	637	635	2,169	3,697	3,708	3,709	3,715	3,681	3,696	3,705	3,693	3,705	3,723	3,684	3,693	3,705	3,707
Vic	NVIC	6,138	5,574	4,653	5,668	4,712	6,332	5,222	5,488	5,435	8,102	8,485	8,435	8,452	8,282	7,867	7,290	7,321	7,120	7,341	6,939

Table 9-9 New Capacity (MW Cumulative) – Most Likely Scenario – TFTR Case

Zone	Type	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
CAN	Biomass	0	0	4	4	4	100	100	100	100	100	100	100	100	100	100	100	100	100
CAN	OCGT	0	0	0	0	0	0	0	0	0	93	369	409	436	457	481	490	503	525
CAN	Wind	0	0	880	880	880	880	880	880	880	1,122	1,122	1,122	1,122	1,122	1,122	1,264	1,283	1,283
NCEN	Biomass	0	0	0	0	0	3	33	46	100	100	100	100	100	100	100	100	100	100
NCEN	OCGT	0	0	0	0	0	0	0	0	0	0	0	253	443	502	788	1,095	1,255	1,399
NCEN	Wind	0	0	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
NNS	Biomass	0	0	0	0	0	0	0	0	10	100	100	100	100	100	100	100	100	100
NNS	OCGT	0	0	0	0	0	0	0	0	0	0	0	0	262	428	466	945	1,201	1,265
NNS	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	602	603
SWNSW	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	613	643
NQ	Biomass	0	0	0	0	0	0	0	43	80	90	190	200	300	400	400	400	400	400
NQ	OCGT	0	0	0	0	0	0	0	0	0	0	164	475	706	900	900	900	900	900
SEQ	OCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	45	388	742	1,106	1,481
SWQ	Wind	0	489	489	489	489	489	489	489	489	489	489	489	489	490	490	490	490	490
ADE	CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12	110
ADE	OCGT	0	0	0	0	17	17	17	68	132	207	256	345	421	494	582	631	654	772
NSA	Wind	829	829	829	988	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,722	1,722	1,722	1,729
SESA	Biomass	0	0	0	0	100	101	170	214	214	214	214	214	214	214	231	254	269	269
SESA	Wind	0	0	968	968	968	968	968	968	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
TAS	Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	46
TAS	Wind	0	0	841	841	841	841	841	841	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
CVIC	OCGT	0	0	0	0	0	0	403	599	824	1,102	1,275	1,535	1,800	1,800	1,800	1,800	1,800	1,800
CVIC	Wind	388	388	388	952	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,453	1,453	1,457
LV	OCGT	0	0	0	163	493	1,001	1,208	1,208	1,208	1,208	1,208	1,208	1,208	1,480	1,774	2,111	2,319	2,628
MEL	Wind	0	0	0	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
NVIC	OCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	23

Table 9-10 Generation by Zone (GWh) – Most Likely Scenario – TFTR Case

Region	Zone	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
NSW	CAN	1,133	1,139	1,134	1,134	3,828	3,849	3,848	4,711	4,684	4,683	4,655	5,413	5,459	5,434	5,425	5,424	5,403	5,851	5,960	5,924
NSW	NCEN	62,669	60,765	61,578	62,497	59,688	63,595	64,031	65,294	66,639	71,003	72,654	73,053	74,972	77,010	81,881	81,944	83,709	85,122	84,743	87,367
NSW	NNS	0	0	0	0	0	0	0	0	0	0	86	858	858	858	859	859	859	861	2,705	2,706
NSW	SWNSW	1,950	3,714	3,842	2,859	3,892	2,344	3,368	3,092	3,186	511	182	249	172	364	674	1,339	1,306	1,501	3,149	3,239
Qld	CQ	26,425	26,035	27,071	25,102	26,097	29,153	31,108	31,447	34,201	34,580	35,302	35,808	35,911	37,290	34,536	35,255	36,325	37,881	38,278	38,914
Qld	NQ	621	643	629	629	1,287	2,058	2,058	2,656	629	1,002	1,315	1,402	2,261	2,335	3,243	4,196	4,231	4,233	4,273	4,308
Qld	SEQ	1,057	1,277	1,976	2,207	1	5	7	10	264	290	329	357	372	738	443	616	1,080	1,639	1,750	1,756
Qld	SWQ	29,805	29,807	29,807	32,699	34,303	31,307	30,171	30,173	30,171	30,173	30,169	30,177	30,173	30,177	30,179	30,180	30,268	30,338	30,490	30,742
SA	ADE	780	2,705	881	810	658	600	411	426	464	517	593	643	700	769	829	744	862	968	1,064	1,252
SA	NSA	8,557	7,569	10,022	10,138	9,258	9,476	10,330	10,260	10,338	10,513	10,647	10,801	11,016	11,217	11,396	11,770	11,896	12,200	12,441	12,763
SA	SESA	1,200	1,202	1,199	1,203	4,410	4,421	5,282	5,290	5,893	6,275	6,339	6,356	6,361	6,353	6,367	6,386	6,496	6,685	6,814	6,832
Tas	TAS	9,134	10,532	9,613	9,615	12,366	12,424	12,419	12,419	12,400	12,417	12,908	12,958	12,933	12,948	12,947	12,954	12,895	12,943	12,947	12,886
Vic	CVIC	2,014	2,018	3,241	3,225	3,211	4,933	6,501	6,504	6,477	6,484	6,458	6,457	6,478	6,467	6,480	6,497	6,465	6,474	6,497	6,493
Vic	LV	53,911	50,070	49,072	47,402	42,511	37,839	35,405	35,269	34,706	31,624	30,921	30,958	30,766	31,454	32,108	34,077	34,243	34,875	34,939	35,826
Vic	MEL	620	635	635	637	635	2,169	3,697	3,708	3,709	3,715	3,681	3,696	3,705	3,693	3,705	3,723	3,685	3,692	3,706	3,708
Vic	NVIC	6,136	5,574	4,660	5,668	4,582	6,208	5,135	5,424	5,324	8,122	8,485	8,397	8,491	8,284	7,919	7,293	7,293	7,100	7,340	6,931

Appendix D NTNDP 2010 Results

The appendix presents the detailed modelling results of the NTNDP 2010 Scenario.

The following are presented:

- New generation capacity (MW) by region for each of the cases;
- Generation (GWh) by zone for each of the cases.

Table 9-11 New Capacity (MW Cumulative) – NTNDP 2010 Scenario – Status Quo Low Case

Zone	Type	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
CAN	Biomass	0	0	0	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100
CAN	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	450
NCEN	Biomass	0	0	0	0	0	0	0	0	0	100	100	100	100	100	100	100	100	100
NCEN	OCGT	0	0	0	0	0	0	24	654	1,222	1,428	1,428	1,428	1,428	1,428	1,428	1,428	1,500	1,500
NNS	Biomass	0	0	0	0	0	0	0	0	0	0	100	100	100	100	100	100	100	100
NNS	CCGT	0	0	0	0	0	0	0	0	0	0	143	386	733	1,108	1,514	1,927	2,429	2,990
SWNSW	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100
NQ	Biomass	0	0	0	100	200	300	300	400	400	400	400	400	400	400	400	400	400	400
NQ	CCGT	0	0	0	0	0	0	0	0	0	149	500	833	1,150	1,520	1,983	2,654	3,000	3,000
NQ	OCGT	0	0	0	0	0	53	68	68	68	68	68	68	68	68	68	86	268	533
SEQ	CCGT	0	0	0	0	0	0	500	819	1,089	1,279	1,279	1,279	1,279	1,279	1,279	1,279	1,480	1,975
SEQ	OCGT	0	23	23	42	480	920	920	920	920	920	920	920	920	920	920	920	920	920
SWQ	CCGT	0	0	0	0	0	0	157	157	157	157	157	157	157	157	157	157	157	157
SWQ	OCGT	0	550	1,150	1,601	1,665	1,689	1,689	1,689	1,689	1,689	1,689	1,689	1,689	1,689	1,689	1,689	1,689	1,689
ADE	CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	110	228	400	600
NSA	OCGT	0	0	0	0	0	0	0	125	125	168	247	247	247	329	329	329	329	329
NSA	Wind	0	500	1,000	1,495	1,738	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750
SESA	Biomass	0	0	0	0	0	0	0	0	100	100	100	194	279	300	300	300	300	300
SESA	Geothermal	0	0	0	0	0	0	181	200	200	200	200	200	200	200	200	200	200	200
SESA	Wind	0	450	450	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700
TAS	Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	200
TAS	Wind	0	0	0	100	500	518	931	1,299	1,299	1,299	1,299	1,299	1,299	1,299	1,299	1,299	1,299	1,333
CVIC	CCGT	0	0	0	0	0	0	0	0	0	0	0	426	662	924	1,267	1,267	1,267	1,267
CVIC	Geothermal	0	0	0	0	0	350	400	400	400	400	400	400	400	400	400	400	400	400
CVIC	OCGT	0	0	0	0	0	0	121	459	656	929	1,035	1,035	1,035	1,035	1,035	1,035	1,035	1,035
CVIC	Wind	0	0	0	0	500	1,000	1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,450
LV	CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	500	1,000	1,500
LV	Geothermal	0	0	0	0	0	0	119	200	200	200	200	200	200	200	200	200	200	200
LV	OCGT	47	281	442	585	837	908	908	908	908	908	908	908	908	908	908	908	908	908
MEL	Wind	0	0	0	141	141	641	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
NVIC	OCGT	0	0	0	0	4	4	300	300	300	408	600	600	600	600	600	600	600	600

Table 9-12 Generation by Zone (GWh) – NTNDP 2010 Scenario – Status Quo Low Case

Region	Zone	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
NSW	CAN	1,134	1,135	1,134	1,134	1,134	1,134	1,134	1,134	1,992	1,991	1,992	1,992	1,992	1,993	1,992	1,992	1,992	1,992	1,992	3,379
NSW	NCEN	64,418	64,619	66,680	72,194	74,514	75,612	77,970	78,635	79,501	82,642	84,283	85,375	84,239	83,572	82,019	81,235	78,777	77,519	75,438	71,186
NSW	NNS	0	0	0	0	0	0	0	0	0	0	0	0	2,061	4,105	7,026	10,181	13,597	17,073	21,299	26,020
NSW	SWNSW	1,590	2,391	1,483	230	117	169	198	650	579	853	967	1,060	969	925	894	781	914	1,176	1,398	1,815
Qld	CQ	31,473	31,596	33,812	28,507	29,944	31,979	35,695	37,389	37,752	40,066	40,531	40,836	40,844	40,843	40,879	29,760	29,889	29,575	27,716	26,979
Qld	NQ	637	630	616	2,672	2,673	3,515	4,504	5,363	5,362	4,593	4,610	5,217	6,668	7,964	9,456	17,924	22,133	27,667	30,603	30,434
Qld	SEQ	571	899	989	3,415	3,418	2,628	3,608	3,784	5,530	5,735	7,046	7,612	8,114	8,794	9,379	11,315	10,564	9,713	12,681	16,383
Qld	SWQ	28,249	29,808	29,811	35,039	35,042	35,270	31,424	31,327	32,182	31,779	32,078	32,369	32,349	32,189	31,969	33,489	33,196	32,670	32,566	32,462
SA	ADE	2,234	1,810	1,780	2,329	1,489	864	746	711	868	1,058	1,250	1,374	1,663	1,821	2,109	2,455	2,819	3,352	3,935	4,339
SA	NSA	8,494	8,915	8,949	9,156	10,821	12,161	12,497	12,823	11,755	11,892	11,878	12,180	12,369	12,304	12,253	12,353	12,532	12,743	12,892	13,033
SA	SESA	942	941	941	2,431	2,436	3,283	3,260	3,279	4,818	4,987	5,845	5,850	5,834	6,657	7,369	7,552	7,560	7,564	7,560	7,557
Tas	TAS	9,872	9,793	8,694	10,201	9,945	9,927	11,283	11,347	12,709	13,920	13,939	13,936	13,943	13,917	13,941	13,935	13,940	13,921	14,711	15,430
Vic	CVIC	1,979	2,016	2,016	2,049	2,032	2,016	3,543	8,191	9,988	9,963	9,971	9,962	9,951	13,378	15,404	17,722	20,636	20,629	20,629	20,631
Vic	LV	51,799	53,867	53,902	42,147	42,340	41,217	39,292	35,835	33,425	34,136	34,590	36,371	37,380	34,369	32,969	32,148	31,878	35,059	37,711	39,511
Vic	MEL	444	614	636	634	635	1,071	1,066	2,605	3,699	3,705	3,707	3,708	3,691	3,712	3,691	3,698	3,706	3,707	3,699	3,702
Vic	NVIC	6,883	6,083	6,343	9,238	8,550	8,483	8,457	7,983	8,057	7,767	7,650	7,553	7,648	7,692	7,727	7,836	7,714	7,476	7,351	6,975

Table 9-13 New Capacity (MW Cumulative) – NTNDP 2010 Scenario – Status Quo Moderate Case

Zone	Type	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
CAN	Biomass	0	0	0	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100
CAN	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	250
NCEN	Biomass	0	0	0	0	0	0	0	0	0	100	100	100	100	100	100	100	100	100
NCEN	OCGT	0	0	0	0	0	0	24	654	1,222	1,428	1,571	1,571	1,571	1,571	1,571	1,571	1,571	1,571
NNS	Biomass	0	0	0	0	0	0	0	0	0	0	100	100	100	100	100	100	100	100
NNS	CCGT	0	0	0	0	0	0	0	0	0	0	0	243	590	965	1,371	1,784	2,358	2,925
NNS	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	35
SWNSW	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	160
NQ	Biomass	0	0	0	100	200	300	300	400	400	400	400	400	400	400	400	400	400	400
NQ	CCGT	0	0	0	0	0	0	0	0	0	339	690	1,023	1,340	1,710	2,173	2,839	3,000	3,000
NQ	OCGT	0	0	0	0	0	58	58	58	58	58	58	58	58	58	58	81	263	504
SEQ	CCGT	0	0	0	0	0	0	593	912	1,182	1,182	1,182	1,182	1,182	1,182	1,182	1,182	1,568	2,086
SEQ	OCGT	0	0	0	42	466	835	835	835	835	835	835	835	835	835	835	835	835	835
SWQ	CCGT	0	0	0	0	0	0	69	69	69	69	69	69	69	69	69	69	69	69
SWQ	OCGT	0	573	1,173	1,601	1,679	1,769	1,779	1,779	1,779	1,779	1,779	1,779	1,779	1,779	1,779	1,779	1,779	1,779
ADE	CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	82	192	306	728	800
NSA	OCGT	0	0	0	0	0	0	0	125	125	168	247	247	247	247	247	247	247	247
NSA	Wind	0	500	1,000	1,495	1,738	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750
SESA	Biomass	0	0	0	0	0	0	0	0	100	100	100	194	279	300	300	300	300	300
SESA	Geothermal	0	0	0	0	0	0	181	200	200	200	200	200	200	200	200	200	200	200
SESA	Wind	0	450	450	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700
TAS	Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	200
TAS	Wind	0	0	0	100	500	519	939	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,400
CVIC	CCGT	0	0	0	0	0	0	0	0	0	0	0	425	661	923	923	923	923	1,115
CVIC	Geothermal	0	0	0	0	0	350	400	400	400	400	400	400	400	400	400	400	400	400
CVIC	OCGT	0	0	0	0	0	0	0	206	220	301	600	600	600	600	600	600	600	600
CVIC	Wind	0	0	0	0	500	1,000	1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,450
LV	CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	500	884	1,500	1,500
LV	Geothermal	0	0	0	0	0	0	119	200	200	200	200	200	200	200	200	200	200	200
LV	OCGT	47	281	442	585	673	744	744	744	744	744	744	744	744	744	744	744	744	744
MEL	Wind	0	0	0	141	141	641	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
NVIC	OCGT	0	0	0	0	168	168	585	717	900	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200

Table 9-14 Generation by Zone (GWh) – NTNDP 2010 Scenario – Status Quo Moderate Case

Region	Zone	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
NSW	CAN	1,134	1,135	1,134	1,134	1,134	1,134	1,134	1,134	1,992	1,991	1,992	1,992	1,992	1,993	1,992	1,992	1,992	1,992	1,992	2,763
NSW	NCEN	64,311	64,603	66,546	72,191	74,514	75,612	77,970	78,634	79,527	82,652	84,283	85,367	85,097	84,287	83,009	82,207	79,373	78,209	75,726	71,807
NSW	NNS	0	0	0	0	0	0	0	0	0	0	0	0	858	2,902	5,822	8,978	12,394	15,869	20,703	25,576
NSW	SWNSW	1,673	2,391	1,582	233	117	169	198	651	572	852	967	1,060	1,024	967	925	913	930	1,156	1,398	1,965
Qld	CQ	31,532	31,609	33,912	28,506	29,944	31,979	35,695	37,389	37,749	40,062	40,525	40,831	40,844	40,843	40,879	29,828	29,947	29,593	27,700	27,060
Qld	NQ	637	630	616	2,672	2,673	3,515	4,504	5,363	5,362	4,591	4,610	6,010	7,487	9,076	10,607	19,520	23,736	28,900	30,603	30,434
Qld	SEQ	478	910	953	3,415	3,418	2,628	3,608	3,784	5,908	6,114	7,578	7,352	7,869	8,389	8,801	10,267	9,516	9,007	13,155	17,032
Qld	SWQ	28,249	29,808	29,811	35,039	35,042	35,270	31,424	31,327	31,806	31,402	31,546	31,839	31,863	31,638	31,464	32,957	32,668	32,268	32,140	32,014
SA	ADE	2,263	1,810	1,781	2,328	1,486	856	741	713	867	1,061	1,248	1,373	1,658	1,822	2,108	2,496	2,819	3,380	4,066	4,442
SA	NSA	8,494	8,918	8,948	9,156	10,821	12,163	12,501	12,823	11,757	11,889	11,873	12,176	12,368	12,311	12,249	12,366	12,520	12,733	12,833	12,988
SA	SESA	942	941	941	2,431	2,436	3,283	3,260	3,279	4,818	4,987	5,845	5,850	5,834	6,657	7,369	7,555	7,560	7,564	7,561	7,557
Tas	TAS	9,873	9,791	8,695	10,201	9,945	9,927	11,283	11,350	12,735	13,923	13,943	13,940	13,946	13,921	13,944	13,939	13,944	13,924	14,714	15,621
Vic	CVIC	1,979	2,016	2,016	2,049	2,032	2,016	3,543	8,191	9,990	9,964	9,973	9,963	9,954	13,395	15,417	17,716	17,736	17,727	17,729	19,346
Vic	LV	51,800	53,867	53,914	42,151	42,343	41,224	39,294	35,831	33,368	34,122	34,591	36,376	37,647	34,685	33,109	32,242	35,251	38,296	40,795	40,538
Vic	MEL	444	614	636	634	635	1,070	1,064	2,603	3,699	3,705	3,706	3,707	3,690	3,712	3,691	3,699	3,705	3,707	3,698	3,703
Vic	NVIC	6,795	6,083	6,240	9,235	8,550	8,483	8,457	7,982	8,065	7,768	7,650	7,553	7,590	7,647	7,694	7,703	7,694	7,479	7,350	6,978

Table 9-15 New Capacity (MW Cumulative) – NTNDP 2010 Scenario – Status Quo High Case

Zone	Type	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
CAN	Biomass	0	0	0	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100
CAN	OCGT	0	0	0	0	0	0	23	145	229	229	229	229	229	229	229	229	229	229
CAN	Wind	0	0	0	0	0	0	10	10	10	10	10	10	10	10	10	10	10	443
NCEN	Biomass	0	0	0	0	0	0	0	0	0	100	100	100	100	100	100	100	100	100
NCEN	OCGT	0	0	0	0	0	0	0	508	992	1,198	1,341	1,584	1,584	1,584	1,584	1,584	1,584	1,584
NNS	Biomass	0	0	0	0	0	0	0	0	0	0	100	100	100	100	100	100	100	100
NNS	CCGT	0	0	0	0	0	0	0	0	0	0	0	0	347	722	1,128	1,541	2,116	2,682
NQ	Biomass	0	0	0	100	200	300	300	400	400	400	400	400	400	400	400	400	400	400
NQ	CCGT	0	0	0	0	0	0	0	0	0	129	480	813	1,130	1,500	1,963	2,651	3,000	3,000
NQ	OCGT	0	0	0	0	0	47	47	47	47	47	47	47	47	47	47	48	262	504
SEQ	CCGT	0	0	0	0	0	0	500	819	1,089	1,299	1,299	1,299	1,299	1,299	1,299	1,299	1,465	1,983
SEQ	OCGT	0	0	0	143	471	941	941	941	941	941	941	941	941	941	941	941	941	941
SWQ	CCGT	0	0	0	0	0	0	172	172	172	172	172	172	172	172	172	172	172	172
SWQ	OCGT	0	573	1,173	1,500	1,674	1,674	1,674	1,674	1,674	1,674	1,674	1,674	1,674	1,674	1,674	1,674	1,674	1,674
ADE	CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	82	192	306	600	600
NSA	OCGT	0	0	0	0	0	0	0	125	125	168	247	247	247	247	247	247	247	247
NSA	Wind	0	500	1,000	1,500	1,738	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750
SESA	Biomass	0	0	0	0	0	0	0	0	100	100	100	194	279	300	300	300	300	300
SESA	Geothermal	0	0	0	0	0	0	181	200	200	200	200	200	200	200	200	200	200	200
SESA	Wind	0	446	446	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700
TAS	Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	200
TAS	Wind	0	0	0	100	500	550	902	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,350
CVIC	CCGT	0	0	0	0	0	0	0	0	0	0	0	265	500	500	500	500	702	1,154
CVIC	Geothermal	0	0	0	0	0	350	400	400	400	400	400	400	400	400	400	400	400	400
CVIC	OCGT	0	0	0	0	0	0	300	300	300	300	600	600	600	600	600	600	600	600
CVIC	Wind	0	0	0	0	500	966	1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,455	1,455
LV	CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	262	606	1,261	1,500	1,500
LV	Geothermal	0	0	0	0	0	0	119	200	200	200	200	200	200	200	200	200	200	200
LV	OCGT	47	281	442	585	841	915	947	1,199	1,199	1,324	1,324	1,324	1,324	1,324	1,324	1,324	1,324	1,324
MEL	Wind	0	0	0	142	142	642	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
NVIC	OCGT	0	0	0	0	0	0	82	169	366	621	621	781	781	781	781	781	781	781

Table 9-16 Generation by Zone (GWh) – NTNDP 2010 Scenario – Status Quo High Case

Region	Zone	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
NSW	CAN	1,134	1,135	1,134	1,134	1,134	1,134	1,134	1,134	2,023	2,022	2,023	2,023	2,024	2,025	2,024	2,024	2,023	2,023	2,023	3,358
NSW	NCEN	64,472	64,660	66,604	72,195	74,514	75,609	77,970	78,639	79,512	82,634	84,258	85,333	85,050	85,800	84,484	83,666	81,355	79,930	77,696	73,819
NSW	NNS	0	0	0	0	0	0	0	0	0	0	0	0	858	858	3,778	6,934	10,350	13,825	18,659	23,429
NSW	SWNSW	1,591	2,391	1,524	231	119	169	198	653	551	849	967	1,054	1,029	1,068	968	967	969	1,105	1,396	1,497
Qld	CQ	31,439	31,541	33,863	28,506	29,943	31,979	35,695	37,388	37,741	40,055	40,513	40,816	40,844	40,843	40,879	29,943	29,936	29,564	27,772	27,215
Qld	NQ	637	630	616	2,672	2,673	3,515	4,504	5,363	5,362	4,587	4,610	5,123	6,600	7,971	9,581	17,817	22,071	27,651	30,603	30,434
Qld	SEQ	616	932	989	3,415	3,417	2,628	3,608	3,784	5,494	5,697	6,977	7,640	8,164	8,899	9,497	11,696	10,757	9,811	12,593	16,370
Qld	SWQ	28,249	29,808	29,811	35,039	35,041	35,270	31,424	31,327	32,223	31,821	32,145	32,445	32,466	32,397	32,169	33,556	33,329	32,861	32,722	32,677
SA	ADE	2,233	1,810	1,787	2,335	1,495	858	741	713	865	1,058	1,249	1,373	1,661	1,826	2,125	2,509	2,834	3,382	4,017	4,378
SA	NSA	8,494	8,923	8,948	9,156	10,821	12,175	12,499	12,818	11,757	11,883	11,880	12,179	12,369	12,347	12,337	12,417	12,556	12,733	12,878	13,050
SA	SESA	942	941	941	2,418	2,423	3,283	3,260	3,279	4,818	4,987	5,845	5,850	5,834	6,658	7,369	7,555	7,560	7,564	7,560	7,557
Tas	TAS	9,853	9,812	8,695	10,200	9,947	9,927	11,283	11,452	12,614	13,924	13,943	13,940	13,947	13,921	13,945	13,940	13,944	13,924	14,715	15,484
Vic	CVIC	1,979	2,016	2,016	2,049	2,032	2,016	3,543	8,085	9,990	9,964	9,973	9,963	9,953	12,169	14,157	14,161	14,181	14,171	15,887	19,551
Vic	LV	51,800	53,849	53,914	42,154	42,346	41,208	39,290	35,830	33,467	34,120	34,577	36,369	37,640	36,244	34,476	35,872	38,591	42,021	42,595	40,368
Vic	MEL	444	614	636	634	635	1,075	1,070	2,609	3,699	3,705	3,706	3,707	3,691	3,712	3,692	3,699	3,706	3,708	3,698	3,701
Vic	NVIC	6,882	6,083	6,301	9,237	8,548	8,483	8,457	7,980	8,086	7,771	7,651	7,559	7,586	7,542	7,649	7,650	7,649	7,504	7,350	6,983

Table 9-17 New Capacity (MW Cumulative) – NTNDP 2010 Scenario – TFTR Case

Zone	Type	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
CAN	Biomass	0	0	0	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100
CAN	OCGT	0	0	0	0	0	0	21	90	90	90	90	90	90	90	90	90	90	90
CAN	Wind	0	0	0	0	0	0	52	52	52	52	52	52	52	52	52	52	405	405
NCEN	Biomass	0	0	0	0	0	0	0	0	23	100	100	100	100	100	100	100	100	100
NCEN	OCGT	0	0	0	0	0	0	0	561	1,106	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,319
NNS	Biomass	0	0	0	0	0	0	0	0	0	17	67	85	100	100	100	100	100	100
NNS	CCGT	0	0	0	0	0	0	0	0	0	0	193	418	750	1,125	1,531	1,944	2,501	3,069
NNS	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	238
SWNSW	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	160
NQ	Biomass	0	0	0	100	200	300	300	400	400	400	400	400	400	400	400	400	400	400
NQ	CCGT	0	0	0	0	0	0	0	0	0	339	690	1,023	1,340	1,710	2,173	2,859	3,000	3,000
NQ	OCGT	0	0	0	0	0	79	79	79	79	79	79	79	79	79	79	81	263	529
SEQ	CCGT	0	0	0	0	0	0	573	892	1,162	1,162	1,162	1,162	1,162	1,162	1,162	1,162	1,568	2,063
SEQ	OCGT	0	0	0	42	466	838	838	838	838	838	838	838	838	838	838	838	838	838
SWQ	CCGT	0	0	0	0	0	0	69	69	69	69	69	69	69	69	69	69	69	69
SWQ	OCGT	0	573	1,173	1,601	1,679	1,746	1,776	1,776	1,776	1,776	1,776	1,776	1,776	1,776	1,776	1,776	1,776	1,776
ADE	CCGT	0	0	0	0	0	0	0	0	0	0	0	12	12	115	188	302	403	496
ADE	OCGT	0	0	0	0	0	0	45	187	187	247	276	276	276	276	312	312	327	533
NSA	Wind	0	500	1,000	1,500	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,727	1,727
SESA	Biomass	0	0	0	0	0	0	0	0	77	83	133	215	300	300	300	300	300	300
SESA	Geothermal	0	0	0	0	0	98	200	200	200	200	200	200	200	200	200	200	200	200
SESA	Wind	0	455	455	653	653	653	653	653	653	653	653	653	653	653	653	653	653	653
TAS	Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	27	127	227
TAS	Wind	0	0	0	108	500	550	983	1,293	1,293	1,293	1,293	1,293	1,293	1,293	1,293	1,293	1,293	1,322
CVIC	CCGT	0	0	0	0	0	0	0	0	0	0	96	517	517	517	517	517	958	1,410
CVIC	Geothermal	0	0	0	0	0	252	400	400	400	400	400	400	400	400	400	400	400	400
CVIC	OCGT	0	0	0	0	114	114	114	135	135	414	414	414	414	414	414	414	414	414
CVIC	Wind	0	0	0	0	500	1,000	1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,450	1,450
LV	CCGT	0	0	0	0	0	0	0	0	0	0	0	4	239	501	845	1,500	1,500	1,500
LV	Geothermal	0	0	0	0	0	0	100	200	200	200	200	200	200	200	200	200	200	200
LV	OCGT	47	281	442	582	723	835	835	835	835	835	835	835	835	835	835	835	835	835
MEL	Wind	0	0	0	181	181	681	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
NVIC	OCGT	0	0	0	0	1	49	398	698	895	996	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200

Table 9-18 Generation by Zone (GWh) – NTNDP 2010 Scenario – TFTR Case

Region	Zone	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
NSW	CAN	1,134	1,135	1,134	1,135	1,134	1,134	1,134	1,134	2,152	2,150	2,151	2,152	2,151	2,153	2,152	2,151	2,151	2,151	3,235	3,241
NSW	NCEN	64,313	64,707	66,653	72,191	74,514	75,613	78,014	78,640	79,329	82,505	84,188	85,175	84,038	83,382	81,587	80,864	78,253	76,853	74,052	70,241
NSW	NNS	0	0	0	0	0	0	0	0	0	0	0	144	2,197	4,244	7,167	10,322	13,738	17,213	21,899	27,413
NSW	SWNSW	1,662	2,391	1,491	229	117	169	198	655	579	832	967	1,039	968	923	858	747	856	1,099	1,443	2,161
Qld	CQ	31,532	31,538	33,911	28,507	29,943	31,979	35,695	37,388	37,764	40,078	40,538	40,837	40,844	40,843	40,879	29,782	29,967	29,614	27,513	26,859
Qld	NQ	637	630	616	2,672	2,673	3,515	4,504	5,364	5,362	4,598	4,609	6,024	7,454	8,974	10,630	19,534	23,771	29,035	30,488	30,434
Qld	SEQ	481	908	989	3,416	3,418	2,628	3,608	3,783	5,872	6,071	7,528	7,286	7,787	8,244	8,677	10,164	9,410	8,871	13,206	16,856
Qld	SWQ	28,249	29,808	29,811	35,039	35,042	35,270	31,423	31,327	31,834	31,430	31,573	31,863	31,819	31,607	31,472	32,987	32,682	32,212	32,131	31,851
SA	ADE	2,262	1,809	1,781	2,323	1,482	854	763	703	853	1,046	1,235	1,371	1,655	1,825	2,119	2,504	2,819	3,395	3,917	4,363
SA	NSA	8,494	8,916	8,948	9,155	10,820	12,204	12,479	12,582	11,771	11,931	12,000	12,241	12,286	12,198	12,140	12,266	12,423	12,634	12,787	12,862
SA	SESA	942	941	941	2,446	2,451	3,125	3,104	3,965	4,827	4,830	5,487	5,550	5,960	6,680	7,393	7,399	7,403	7,407	7,405	7,400
Tas	TAS	9,873	9,791	8,695	10,204	9,942	9,953	11,283	11,453	12,883	13,900	13,919	13,916	13,923	13,897	13,921	13,916	13,920	14,132	14,900	15,608
Vic	CVIC	1,979	2,016	2,016	2,049	2,032	2,016	3,543	7,329	9,990	9,965	9,974	9,963	10,692	14,104	14,301	14,305	14,325	14,315	18,028	21,718
Vic	LV	51,800	53,831	53,816	42,135	42,336	41,194	39,287	36,006	33,263	34,272	34,811	36,548	36,601	33,741	34,312	35,841	38,575	41,601	40,136	38,299
Vic	MEL	444	614	636	634	635	1,195	1,189	2,727	3,699	3,705	3,709	3,707	3,691	3,711	3,691	3,698	3,705	3,707	3,701	3,705
Vic	NVIC	6,807	6,084	6,335	9,239	8,550	8,482	8,457	7,978	8,057	7,789	7,650	7,575	7,649	7,693	7,765	7,872	7,775	7,510	7,410	6,894