AN ASSESSMENT OF THE MODELLING CONDUCTED BY TRANSGRID AND AUSGRID FOR THE "POWERING SYDNEY'S FUTURE" PROGRAM

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1. Introduction

This note is an assessment of the modelling submitted by TransGrid and Ausgrid in support of the "Powering Sydney's Future" network upgrade program. In this note I will refer to TransGrid and Ausgrid collectively as "the parties".

The Powering Sydney's Future (or PSF) project is driven by concerns over ageing 330 kV and 132 kV underground cables used to supply power to central Sydney. The parties are concerned that decreasing reliability, coupled with on-going load growth in central Sydney, will lead to increasing frequency and severity of episodes of load shedding.

The parties propose a range of options to replace ageing cables to improve network reliability, including different timing and sequencing of upgrade options. The parties have carried out detailed and highly sophisticated modelling to assess these options. This modelling is set out in a large number of Excel spreadsheets.

I have examined those spreadsheets and the accompanying documentation. A lot of the detailed analysis in those spreadsheets is consistent with fundamental economic principles. However, I have several concerns with the modelling which is set out in detail in this paper.

2. Background

What does economic theory tell us about when to upgrade a transmission line and how to choose between different upgrade options?

Most fundamentally, a transmission line should be upgraded only if the benefit exceeds the cost. The benefit is the present value of the future savings in congestion costs that would arise in the absence of the upgrade.[1] The cost is primarily the physical capital costs associated with procuring and installing the upgrade. I discuss further below how to go about the estimation of congestion costs.

However, the cost benefit analysis of a transmission line upgrade is more complex than this simple summary suggests. Often there is more than one way to upgrade a network (more than one upgrade option), including possible non-network solutions. It is often the case that an upgrade can be carried out in stages or staggered over time. Almost always there is some discretion over when the upgrade should be carried out. Technically we should consider each of these variations or possibilities as a different option.

If there are options which are mutually exclusive, the decision is no longer to carry out the upgrade if the NPV is positive; instead, the option with the *highest* NPV should be chosen. This implies, for example, that where there is a choice of timing, the upgrade should be carried out

[1] Together with any reduction in maintenance costs or environmental harm costs. But these costs are relatively small and not considered further.

today only when the NPV of carrying out the upgrade today exceeds the NPV of waiting and carrying out the upgrade in the future. This is discussed further below.

Estimating the cost of congestion

Fundamentally, the assessment of a transmission upgrade involves a comparison of the cost of congestion with the cost of the upgrade.

The cost of congestion is the additional economic cost incurred by customers required to balance supply and demand within the central Sydney region when the network (importing remote generation) cannot meet all of the local demand itself. This cost has two components: (a) the cost of any additional local generation (or battery storage) required to meet demand at such times; and (b) the economic cost arising from any foregone demand at such times.

The economic cost of congestion is not a static figure, but varies widely depending on demand and supply conditions in the market at any given point in time. The cost of congestion depends on how much customers are willing to pay to continue to consume at a point in time (or, put another way, it depends on each customer's willingness to defer their consumption to another time – which depends on access to storage, and thermal inertia and so on) and it depends on the availability of local resources to meet local demand. The cost of congestion is therefore dynamic and time-varying, reflecting supply and demand conditions in the market.

In the case of the Powering Sydney's Future Project, demand is forecast to increase over time. Therefore, in the absence of any change in the network serving central Sydney, congestion must get worse over time (i.e., become more frequent and more severe over time). For any given conceivable upgrade, there will (almost certainly) arise a point at which an upgrade of the network is economically desirable. This observation makes clear that, in the assessment of the PSF project, the question is not whether an upgrade to the network is required; the question is only the *nature and timing* of the upgrade.

This observation can be summarised as follows:

> **Given the assumption that demand is increasing while the network capability is fixed, some action must be taken eventually; the choice is not *whether* to upgrade the network but *how and when* to upgrade the network. The key question for the PSF project is *which* option to select and *when* to carry it out.**

The parties have presented the cost-benefit analysis for these projects in a way which suggests that an upgrade is substantially NPV positive (in the billions of dollars). This is potentially misleading. Given the assumptions underlying the modelling, the decision is not whether to take action, but when to take action (and what action to take). The relative pros and cons of the options would be clearer if the parties chose some benchmark default action (such as option 1) as the baseline case, and then compared all of the other options to this benchmark or default action.

As noted above, a key question in this analysis is the *timing* of the upgrade. In the discussion that follows I will suggest that the assumptions of the parties (particularly regarding demand and network reliability) have tended to make an upgrade desirable *sooner* than might be the case. The primary question for the AER is not whether an upgrade is required but whether the parties have correctly identified the timing of that upgrade.

There is another further issue which is worth raising. We have just observed that it doesn't make sense to compare the various options to the "do nothing" option, since (at least under the assumptions used by the parties) the "do nothing" option results in such astronomically high congestion costs that it is not credible – eventually the congestion costs would rise to the point that some action must be taken. But the same conclusion applies for any *one* option: specifically, even if some action is taken in the short term, under the assumptions used by the parties (such as continued growth in demand), eventually the congestion cost returns and becomes arbitrarily large. Therefore eventually some *further* action must be taken.

This is important because if we ignore the possibility for further action, the cost-benefit analysis becomes dominated by extremely large congestion costs later in the modelling period. Such congestion costs are not credible since some action would be taken to address them well before they reached astronomic levels.

How should this possibility be taken into account in the modelling? One possibility is to recognise (as demonstrated below) that it is efficient to take action when the savings in congestion costs equals the annualised cost of the capex project. The capex projects under consideration in this analysis all have an annualised cost in the range of $20-$30m. If the same types of projects are available in the future, the congestion cost cannot ever increase above $30m per annum. Therefore it makes sense to cap the congestion cost at around $30m per annum.

> **Given that further action will be taken to address increasing congestion in the future, it is not credible and potentially misleading to model congestion costs increasing to arbitrarily large levels in the future. The congestion costs should be capped at a reasonable level reflecting likely future options, such as $30 m per annum.**

Efficient rationing of scarce network capacity

As noted earlier, the estimated congestion cost depends on how congestion is managed. The management of congestion is largely within the control of network businesses and retailers. Ideally, congestion (when it occurs) should be managed in the most efficient way possible. For example, when congestion occurs end-customers should be induced to make use of their own devices and appliances such as battery back-up or uninterruptible power supply systems.

The parties essentially assume that, in the event of congestion, the resulting shortfall in the supply-demand balance is managed through **involuntary load shedding**. Involuntary load shedding is a particularly inefficient way of rationing scarce network capacity.

Involuntary load shedding involves the interruption to supply of all customers in a region independently of their willingness to supply. Some of the interrupted customers may have alternative sources of supply (such as battery back-up) and would hardly experience any loss or discomfort from an outage. Others may be operating high value economic processes and could experience losses in the millions of dollars per day from an outage. Involuntary load shedding is indiscriminate.

Involuntary load shedding is also unnecessary. The electricity industry is currently undergoing a fundamental transformation that has been said to be the biggest challenge to the industry in decades. This electricity industry transformation centres around the proliferation of devices and appliances which are distributed – that is connected on or near the location of end-customers. These so-called distributed energy resources - which include local generation, battery storage, smart appliances, and so on – give end-customers the ability to choose and to control how they consume electric power.

In particular, increasingly end-customers are showing a willingness to respond to wholesale electricity prices. In effect, end-customers must choose (directly or indirectly) the level of the wholesale price at which they are willing to reduce demand for electricity, and for how long. As the wholesale price increases, at some point we would expect that customers with distributed energy resources would choose to make use of those resources to mitigate the impact of the high wholesale prices.

There are factors which limit the ability of customers to respond. Although large customers in central Sydney are likely to have sophisticated metering, smaller customers may still be on basic accumulation meters which cannot measure each customer's response. Similarly, the wholesale price is currently limited to a ceiling of $14,000/MWh. It is possible that the wholesale price would have to increase to even higher levels to induce some customers to respond.

Nevertheless, these problems are not insurmountable. Establishing mechanisms for efficient rationing of supply and demand at times of network congestion will not be costless, but the cost is likely to be many times lower than the cost of the proposed network upgrades. Network businesses should invest in facilities which allow for smart and efficient rationing of network capacity in order to reduce the cost of congestion, before considering major network upgrades. We can summarise this observation as follows:

> **The parties have, in effect, assumed that there is no possibility for any customer in central Sydney to respond efficiently to episodes of congestion. While this may have been a reasonable assumption in the past, it is no longer a reasonable assumption. With the advent of smart meters, smart appliances, building energy management systems, battery storage and so on, customers can and will respond efficiently to price signals. The parties should be required to establish efficient mechanisms for rationing scarce capacity before investing in network upgrades. The effect of those mechanisms should be included in the cost-benefit analysis of network upgrades.**

At the moment, the parties assume that each kWh of lost load is valued at $90 for customers in the central Sydney area but not in the CBD and $170 for customers in the CBD (this can be compared with the current price cap in the wholesale market of $14/kWh). Now, it is no doubt the case that economic activity in central Sydney is highly economically valuable, and it surely is the case that if a loss of power cut off that economic activity there would be a substantial economic harm.

But under an efficient rationing scheme it may be possible to substantially economise on the consumption of electricity power with little or no impact on that economic activity, especially for short periods. This could occur by temporary deferral of consumption, or by drawing on local storage, or local generation.

Let's suppose that the central Sydney area is faced with a shortfall of network capacity for, say, two hours. By valuing the loss of electricity at $170/kWh the parties in effect assume that:

(a) A small customer with a 3 kW hot water heater in the CBD is prepared to pay $1020 to heat hot water during that time period, rather than simply wait until the period of congestion is over;

(b) A large office building in the CBD with a 100 kW A/C unit, which normally costs $30 an hour to run, the building is prepared to pay $34,000 for cooling during the two-hour congestion episode, rather than letting the building temperature rise somewhat during the period of congestion;

The Tesla Powerwall, with a capacity of 14 kWh, currently costs around $8000. If this is only discharged once per year (at a time of local network congestion, say), a price of $60/kWh would be enough to cover the annualised cost.[2] If the congestion occurs three times per year, a price of \$30/kWh may be sufficient to justify installation of the Powerwall. Once the Powerwall is installed, the customer may not be willing to pay more than, say, \$1-2/kWh during episodes of congestion.

It may not be completely costless to implement some form of mechanism for efficient rationing of scarce capacity. In fact, it might cost in the low millions of dollars. But, the impact on the potential congestion cost at times of rationing could be very significant. As shown below, it doesn't make sense to consider the network upgrades involved in the PSF project until the annual congestion cost reaches around \$25 million per annum. It makes substantial economic sense to implement a mechanism for efficient rationing of scarce capacity long before considering investing in a network upgrade.

How large might the reduction in the congestion cost be? As a rough guess, with efficient rationing we might expect that the average cost of congestion would be on the order of \$20/kWh (i.e., \$20,000/MWh, compared to the wholesale price ceiling of \$14,000/MWh) – that is a reduction of five to ten times the values assumed by the parties (which are \$90 and \$170/kWh as noted above). If demand continues to rise, this average cost of congestion would also rise over time.

The mathematics of network cost-benefit analysis

The parties have estimated the economic cost of congestion by multiplying the amount of load that needs to be curtailed (kWh) per annum by a measure of the average cost of congestion (\$/kWh). Specifically, the parties estimate the annual congestion cost as follows:

$$V\, E[Q_t - K_t | Q_t \geq K_t\,]$$

Here:

V is the economic harm arising per kWh from load shedding (here referred to as the average cost of congestion, also known as the Value of Customer Reliability);

Q_t is the demand (which is assumed to be a non-price-sensitive random variable) in year t; and

K_t is the capacity of the relevant section of the network (which is also assumed to be a random variable) in year t.

The total net benefit associated with a given option is then estimated as the present value of the congestion cost less the (present value) of the upgrade cost, which we can express as follows:

$$NB(X) = \sum_{t=t_0} \frac{VE[Q_t - K_t^X | Q_t \geq K_t^X]}{(1+r)^{t-t_0}} - C(X)$$

Here:

K_t^X is the network capacity in year t after upgrading the network as in option X;

$C(X)$ is the (present value) of the cost of implementing upgrade option X;

[2] \$60 times 14 is \$840 per annum, which is more than enough to cover the \$8000 capital cost assuming a discount rate of around 8 per cent.

r is the discount rate (or "cost of capital"); and

t_0 is the current year.

As noted above, an upgrade option should only be considered where there net benefit (given by the expression above) is positive.

Earlier we noted that a key question in this analysis is the timing of network upgrade options, and that different timings can be considered as though they are different, mutually exclusive options. The optimal timing for a network upgrade option is where the net benefit is maximised.

Let's suppose that we are considering carrying out a given network upgrade. The key question is when to carry out the upgrade. As just noted, the optimal time t^* for the upgrade is where the net benefit is maximised. This means, in particular, that the net benefit from carrying out the upgrade at time t^* must be larger than the net benefit from carrying out the upgrade at time $t^* + 1$.

Let's assume that the cost of the upgrade doesn't depend on when it is carried out. We can calculate the difference in the net benefit at time t^* relative to time $t^* + 1$ as follows:

$$NB(t^*) - NB(t^* + 1) = \frac{1}{(1+r)^{t^*-t_0}} \left(VE\left[Q_{t^*} - K_{t^*}^{SQ} \middle| Q_{t^*} \geq K_{t^*}^{SQ}\right] - VE\left[Q_{t^*} - K_{t^*}^{X} \middle| Q_{t^*} \geq K_{t^*}^{X}\right] - rC \right)$$

Here

K_t^{SQ} is the network capacity in year t in the status quo ("do nothing") option;

K_t^{X} is the network capacity in year t in the options under consideration;

C is the (present value) of the cost of implementing upgrade option X;

What this expression says is that the timing of an upgrade is optimal where the one-period reduction in the congestion cost in that year is equal to the annualised capital cost. Put another way, it doesn't make sense to carry out an upgrade when the reduction in the congestion costs are small relative to the annualised cost of the upgrade. Conversely, we shouldn't wait to carry out an upgrade until the point where the annual reduction in the congestion cost is much larger than the annualised cost of the upgrade. To summarise:

> **The optimal timing of an upgrade depends on the savings in congestion cost and the cost of the upgrade; the smaller the effect of the upgrade and the higher the cost, the longer the upgrade should be deferred before being carried out. If we ignore real options, the upgrade should be carried out in the first year when the reduction in the congestion cost is large enough to outweigh the annualised cost of the upgrade.**

There is one further observation worth making at this point. If there is uncertainty about future demand, it may not make sense to make an investment even if when the savings in congestion cost exceeds the annualised cost. The "real options" investment theory shows that, in the presence of sunk investments and uncertainty about the future, it may make sense to wait before making an irreversible investment.

In other words, in the presence of uncertainty about future demand or cost, it may make sense to not carry out an investment when it first becomes profitable to do so, but to wait to learn more information about the path of future demand or cost. This observation has direct implications here, as discussed further below.

3. The need for an upgrade to supply to central Sydney

According to the modelling carried out by the parties, the need for the proposed upgrades comes about from a forecast rapid increase in the congestion costs in central Sydney. From the analysis above we know that the congestion costs are modelled as an average cost of congestion (V) multiplied by the expected unserved energy ($E[Q - K|Q \geq K]$).

Importantly, the network serving central Sydney has sufficient capacity (3000 MW) to meet all demand for the foreseeable future when all lines are in service. Congestion problems only arise when one or more line is out of service, reducing network capacity. In other words, the primary concern is with reliability of the existing network. My understanding is that the various options considered by the parties do not increase the capacity of the network serving central Sydney, but instead are primarily aimed at reducing the frequency of outages, and improving the capacity of the network to supply at times of outages.

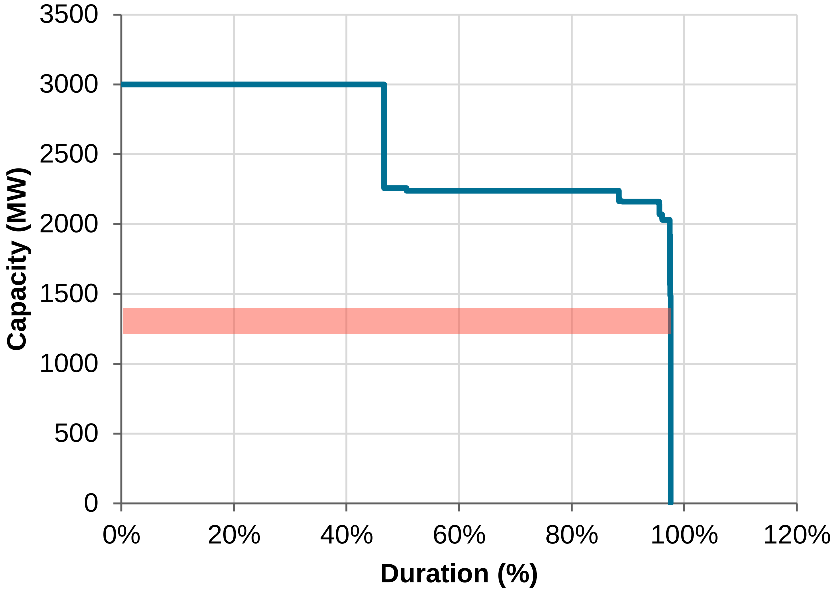
Capacity-duration diagrams

Because reliability is at the heart of this augmentation decision, we must model the capacity of the network to supply the centre of Sydney as *stochastic*. We can illustrate a stochastic value diagrammatically through a "capacity-duration" diagram.

A capacity-duration diagram shows the maximum flow allowed on the network and the proportion of time that maximum flow is expected to occur. If there are outages on different elements of the network the capacity would be expected to reduce. The more outages, the lower the capacity. The capacity-duration curve reflects the impact of different possible combinations of outages (the different "failure modes") and their probability. The maximum capacity (in this case 3000 MW) would normally be expected to be available most of the time, with one network outage occurring for some remaining fraction of the time (and some lower network capacity), and two or more network outages occurring for an even smaller fraction of the time. If a network element was perfectly reliable, its full capacity would be available for 100% of the time. If a network element was highly unreliable the available capacity would be much lower for a large proportion of the time.

The following diagram shows the capacity-duration diagram for the 22 network elements serving central Sydney that is assumed in the modelling for the 2015/16 financial year. As can be seen, the parties assume that this combination of network elements is highly unreliable, with outages reducing the capacity of the system to supply inner Sydney by more than 700 MW (from 3000 MW to under 2300 MW) expected to occur more than half the time. (The red band on Figure 1 represents the forecast peak demand for 2015/16 which is discussed further below).

Figure 1: TransGrid estimated capacity-duration curve 2015/16



Note that the capacity-duration curve does not sum to 100% (although it comes close). This is due to the fact that the parties do not model every single possible failure mode. With 22 network elements there are in principle 4.2 million different potential combinations of failures of network elements. Despite modelling a very large number of different contingencies the parties do not seek to model all of the possible failure modes. In particular, combinations of five or more simultaneous failures are ignored in the modelling.

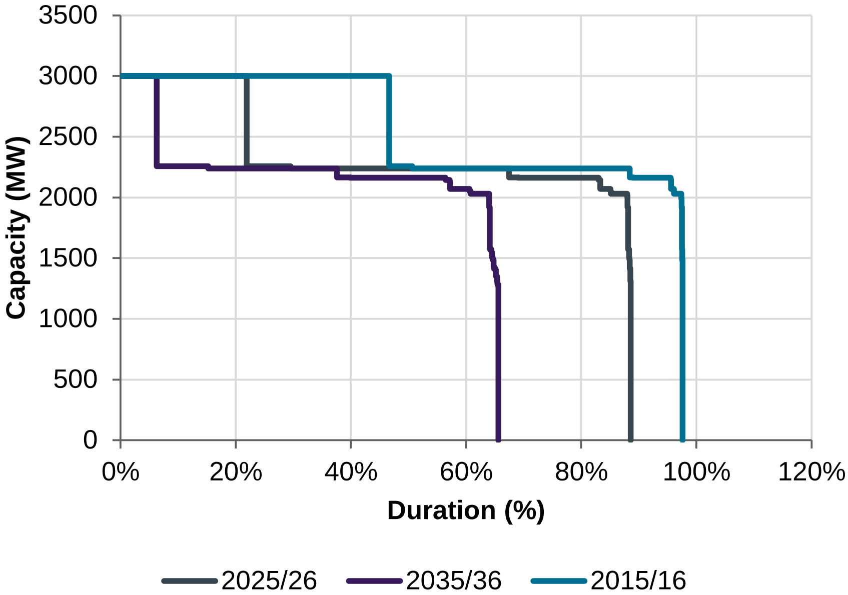
This is arguably a weakness in the modelling. It is not such a significant issue in 2015/16, but the parties forecast that the network will become substantially less reliable over time, so that combinations of five or more simultaneous outages become increasingly likely under the parties' assumptions.

My understanding is that under normal conditions simultaneous outages of two or more unrelated transmission elements is considered a sufficiently rare contingency as to be able to be ignored. However, the parties have assumed quite a high level of unreliability (and rapidly increasing unreliability over time), so the potential for multiple simultaneous outages appears much more likely than is normally the case. One of the consequences is that the parties are led to consider the effects of a *much* larger number of combinations of outages than is normally carried out. This is discussed further below.

The parties estimate the reliability of the network over a forty-year modelling horizon. In particular, they model a network with rapidly increasing unreliability. The unreliability can be illustrated by showing the capacity-duration curve at different time intervals. The following diagram shows the forecast capacity-duration curve for the network serving central Sydney at ten year intervals: 2015/16, 2025/26 and 2035/36.

As can be seen, the unreliability is forecast to reach the point that the network has available its full capacity (3000 MW) for less than 10 per cent of the time, with the network capacity around 2200 MW for the bulk of the time. Again I observe that the parties do not model the full capacity duration curve (the curves do not reach 100%). The greater the forecast level of unreliability the greater the likelihood of multiple outages. The parties partially account for this by modelling a very large number of outages scenarios (around 870 different failure modes are modelled in the do nothing case). But this still does not account for all of the possible combinations of failures.

Figure 2: TransGrid/Ausgrid capacity-duration curve evolution



Demand forecasts

In order to estimate the congestion costs the parties must model not only the reliability of the network, but also the level of demand. To forecast demand the parties take the out-turn or actual demand for central Sydney for the 2013/14 FY and scale up this demand in the manner described below. This approach to forecasting demand has various problems which are discussed further below. For the moment we merely note that this approach forecasts that in 2015/16 the top 5 per cent of demand realisations are above 1265.8 (up to 1432.7 MW) and the top 10 per cent of demand realisations are above 1207.4 MW. This is set out in the following table.

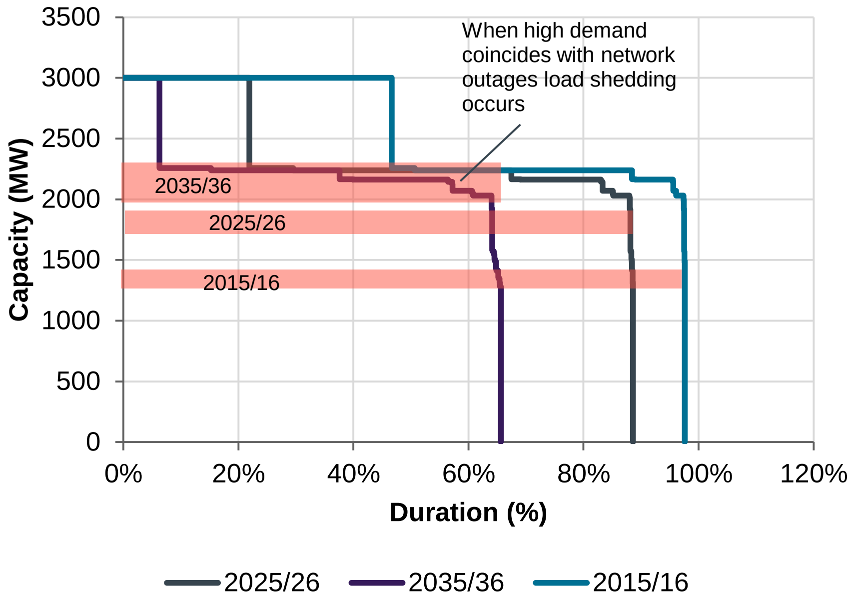
Table 1: TransGrid/Ausgrid forecast peak load Inner Sydney

	2015/16	2025/26	2035/36
Peak demand (MW)	1432.7	1906.8	2225.2
5th percentile	1265.8	1684.7	1966.0
10th percentile	1207.4	1607.0	1875.4

The band of the top 5 per cent of demand realisations is illustrated on the capacity-duration diagram as the red bar in Figure 1 above. As can be seen from this diagram, even with the reliability assumptions used by the parties, there is forecast to be sufficient capacity on the network into central Sydney to exceed the peak forecast demand except on very rare occasions. As a consequence, the parties forecast only a relatively small amount of load shedding in the next few years (see Table 2).

But, as noted above, the parties forecast both declining reliability and increasing demand. Figure 3 illustrates both the capacity-duration curves at ten year intervals and the corresponding forecast peak demand (top 5th percentile). This diagram shows that as demand increases eventually it reaches the point there is a material probability that peak demand will occur at a time when the network capacity is reduced due to outages. This results in a materially increased risk of load shedding and therefore a very substantial estimated cost of congestion.

Figure 3: TransGrid peak demand and reliability evolution



As Table 2 shows, the parties are forecasting that in 20 year's time, there will be about 24,000 MWh of load shedding, costing more than $2.6 billion per annum.

Table 2: TransGrid forecast unserved energy and congestion cost

Option		2016/17	2026/27	2036/37
Do nothing	Lost load (MWh)	14.5	1720	23,938
	Cost ($m/yr)	$1.31	$167.76	$2,616.88
Option 3	Lost load (MWh)	0.0	1.5	292.9
	Cost ($m/yr)	$0.0	$0.17	$28.86

4. The parties' assessment of options

To resolve these issues the parties have proposed a number of options. The options by the parties are as set out in the following table:

Table 3: Proposed Options

Option	Description	Capex cost ($m, NPV)
1	Upgrade in two stages: Stage 1: Upgrade Rookwood to Beaconsfield to 330kV and retire line 41, **commissioned 2020/21**; Stage 2: Install a second Rookwood to Beaconsfield 330 kV line, associated switchyard works, and convert 9S4 to 330kV, **commissioned 2026/27**	$208.5
2	Same as option 1 except line 41 is retained, operating at 132 kV. Commissioning date for stage 2 pushed back to **2028/29**.	$202.5
3	Same as option 1 except the work is carried out in a single stage. Commissioning date is **2022/23**.	$218.7
4	Upgrade in three stages: Stage 1: Remediation works on line 41, **commissioned 2022/23** Stage 2: Upgrade Rookwood to Beaconsfield and line 9S4 to 330 kV, **commissioned 2026/27**; Stage 3: Install a second Rookwood to Beaconsfield 330 kV line, **commissioned 2029/30**	$247.9
5	Same as option 4, except in stage 2, two new 330 kV lines are installed but operated at 132 kV (**commissioned 2025/26**); in stage 3 they are upgrade to 330 kV (**2028/29**).	$256.4
6	Same as option 4, except that two new 330 kV lines are installed in a single step at stage 2 (**2026/27**).	$241.9

It is important to emphasise that the parties have not chosen the commissioning dates arbitrarily. In each case, it is my understanding that the timing of each stage of each project has been independently optimised – that is the timing of each stage of the project is chosen to maximise the net benefit. This is important. As noted earlier, it is important to choose not just which projects to carry out, but also when those projects are optimally carried out, and in what stages.

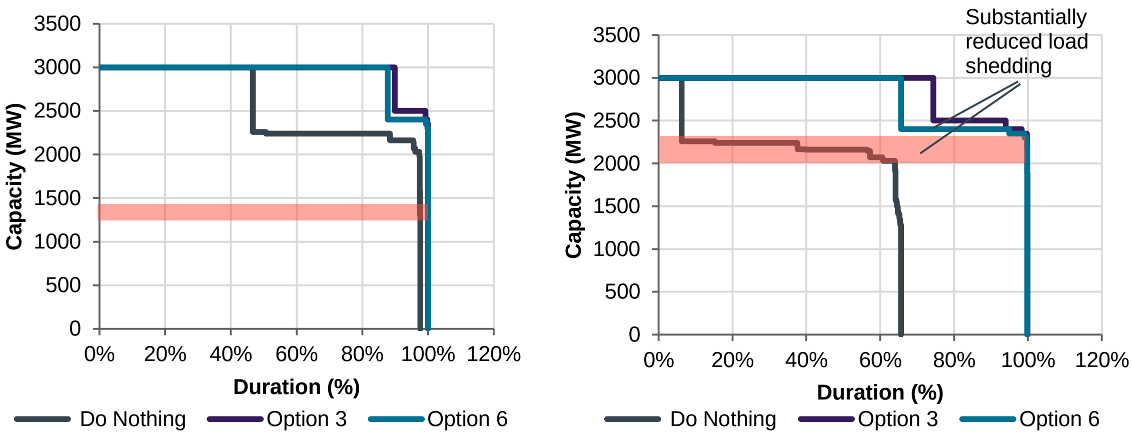
However, there are a couple of problems with the analysis of the parties regarding the choice of timing of each stage of each project.

- In principle, the optimal timing is where the capital cost savings from deferral of a project is equal to the increase in the congestion cost. However, the spreadsheets that I have seen for calculating the optimal timing of each stage of each project do not calculate the increase in the congestion cost – but rather just the absolute congestion cost at each step. This is perhaps not a serious omission. Each stage of each project generally reduces the congestion cost to a low level. So this error is perhaps excusable. However I have not confirmed that it has no impact on the recommendations.

- Options 4-6 all include, as a first stage, remediation of line 41. This is a relatively low cost project which nevertheless involves a substantial capital cost. However, for some reason the parties do not consider the optimal timing for this first stage of remediation (instead, it is assumed to be commissioned in 2022/23 – the same timing as the first stage under options 1-3. This is, in my view, a more serious problem and is discussed further below.

All of these options dramatically reduce the expected unserved energy, especially in later years of the modelling period. The following diagrams show the capacity-duration curves for 2015/16 and 2035/36 for the do-nothing option, and options 3 and 6. As can be seen, the proposed options lead to a substantial improvement in network reliability, resulting in a substantial reduction in the unserved energy (as shown in Table 2).

Figure 4: Effect of options 2015/16 and 2035/36

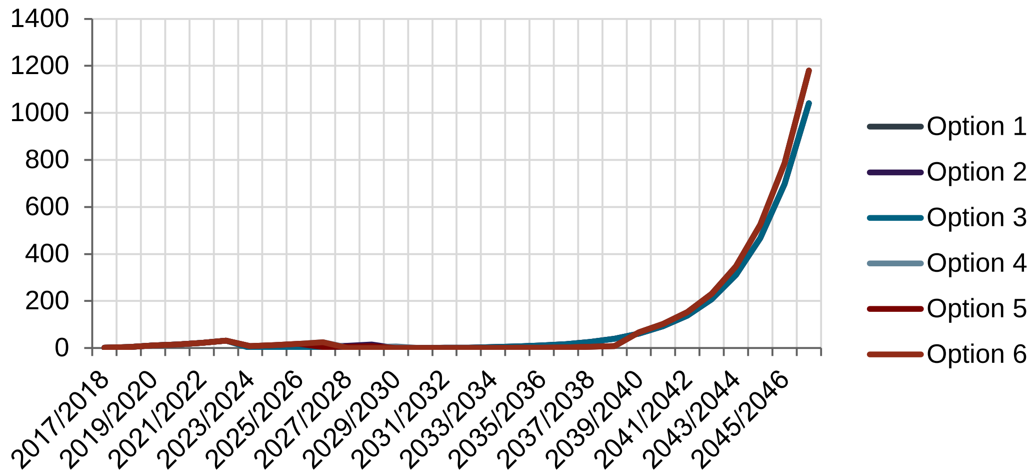


The question for us to address is the following: Which combination of option (that is, which upgrades, carried out in what stages, commissioned at what times) leads to the highest net benefit.

The first observation we will make is that the congestion cost in the "do nothing" option is essentially irrelevant – as noted above, under the assumption of increasing demand and fixed network capacity, the congestion cost under the "do nothing" eventually reaches astronomically high levels. This in effect shows that doing nothing is not a credible option. The question is which one of the options (which upgrades, in what stages, commissioned at what times) leads to the highest net benefit.

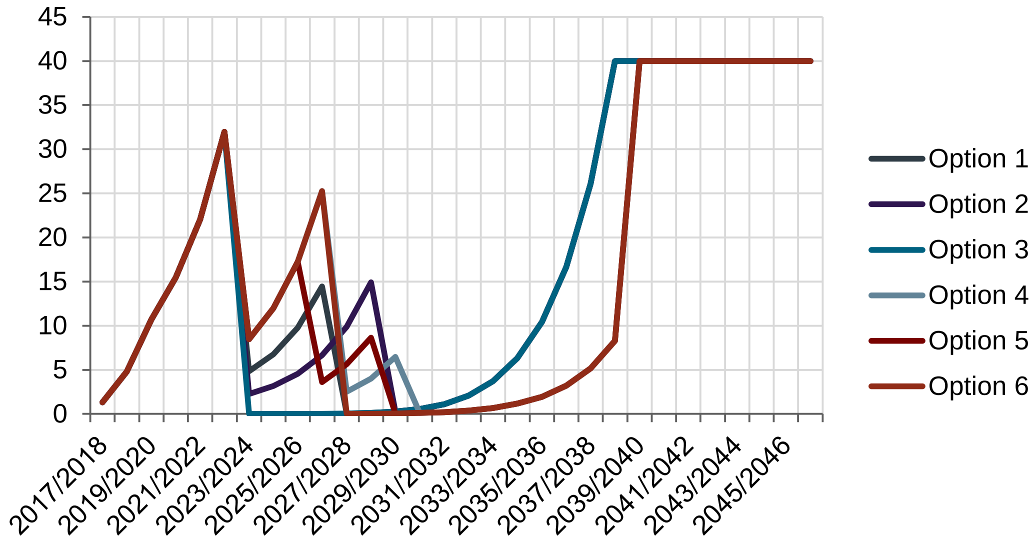
The following graph shows the congestion cost as modelled by the parties under each of the 6 options. The first thing we can observe is that the congestion cost is assumed to reach extraordinarily high levels towards the end of the thirty-year modelling period. This is not credible. When the congestion cost reaches some threshold (say $30-$40 m per annum) some mitigation action would be taken. Allowing the congestion cost to increase in this way could potentially lead the modelling to produce misleading decisions.

Figure 5: Congestion cost as modelled by the parties

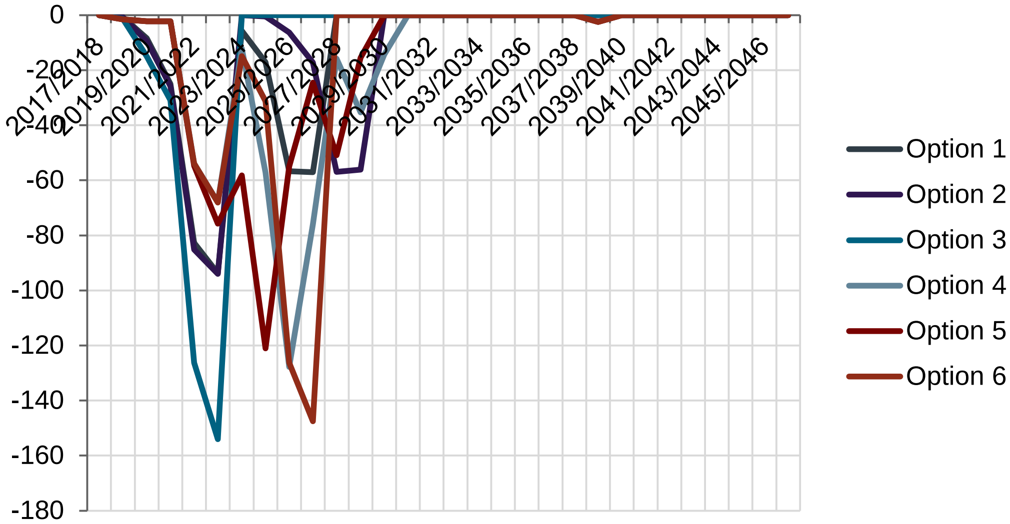


Therefore, let's proceed by capping the annual congestion cost at, say, $40 million. The resulting congestion cost is shown in the figure below. As can be seen, in each option the congestion cost initially rises until the first stage of the upgrade is commissioned. This reduces the congestion cost for a while, but the congestion cost continues to rise in subsequent years. In many of the options there is a second stage, or even a third stage of upgrades.

Figure 6: Congestion cost under each option (capped)



The congestion cost is one side of the trade-off in choosing between the options. The other side is the physical cost. The following diagram shows the costs incurred under each option (these amounts are represented as negative values). The costs illustrate the "staging" of each option. For example, option 3 involves larger up-front expenditure (around 2023/24), whereas option 6 involves smaller expenditure in the first stage (remediation of line 41) followed by another burst of expenditure around 2028/29.

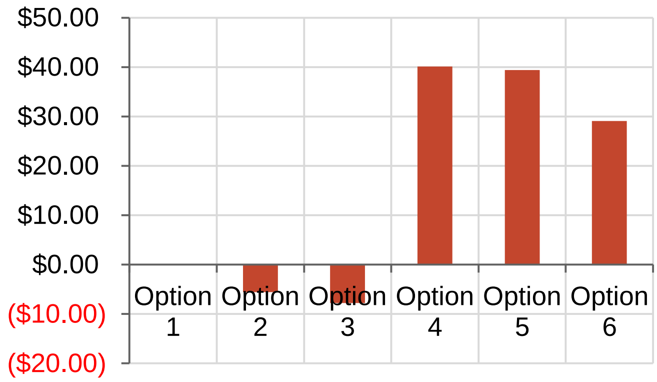


The best option is the option with the lowest total cost (that is, the lowest sum of the congestion cost and the capital cost). On the basis of the modelling by the parties, option 3 is the best option (after capping the congestion cost as noted above).

Table 4: Total cost under each option (timing as modelled, capped congestion)

Option	Congestion Cost ($m)	Capital Cost ($m, NPV)	Total cost (relative to option 1)
1	$143.1	$208.47	n/a
2	$143.6	$202.5	-$5.57
3	$125.1	$218.7	-$7.79
4	$143.8	$247.9	$40.12
5	$134.6	$256.4	$39.42
6	$138.8	$241.9	$29.08

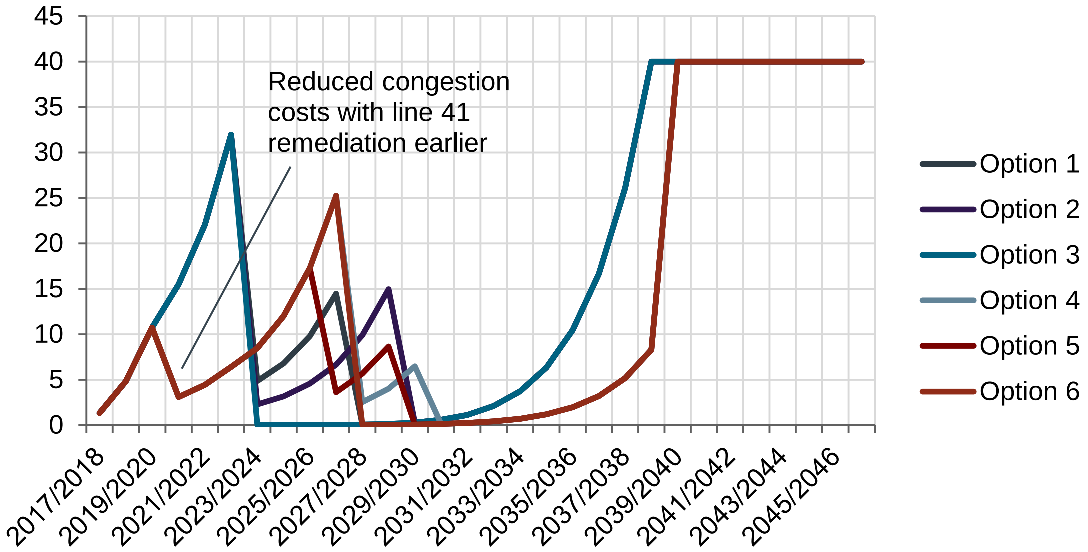
Figure 7: Option 3 is the efficient option (the lowest total cost)



However, as emphasised earlier, in principle we should consider the optimal timing of *all* options. As noted earlier, the parties did not consider the timing of the "line 41 remediation" action (which is the first stage in options 4-6). Instead the parties have simply assumed this action would be commissioned in about 2023/24. This allows the congestion cost to reach $32 m per annum in 2022/23.

This remediation is a relatively low cost option which should be undertaken before the congestion cost reaches such a high level. My analysis suggests that the remediation should optimally be commissioned three-four years earlier, when the congestion cost reaches the level of $10-15 m per annum.

Figure 8: Congestion costs under each option (capped, line 41 remediation earlier)



This assumption has a material impact on the cost-benefit analysis. The congestion cost is now materially lower in options 4-6. As shown in Table 5, the result is that option 6 is the most desirable option, with the remediation of line 41 essentially carried out immediately, and the subsequent installation of two 330 kV lines from Rookwood to Beaconsfield deferred until 2026/27.

Table 5: Congestion cost (Modified timing, congestion cost capped)

Option	Congestion Cost ($m)	Capital Cost ($m, NPV)	Total cost (relative to option 1)
1	$143.1	$208.5	n/a
2	$143.6	$202.5	-$5.6
3	$125.1	$218.7	-$7.8
4	$106.6	$247.9	$2.9
5	$97.4	$256.4	$2.2
6	$101.6	$241.9	-$8.1

In summary, even using the input assumptions put forward by the parties, there are grounds for questioning the recommendations on methodological grounds. Specifically, in my view:

- It is not correct to allow the congestion cost to increase to arbitrarily high levels. A high congestion cost is a trigger for further action. This can be modelled by placing a cap on the congestion cost.
- The parties have carefully selected the optimal timing for each stage of each option. However they did not consider the optimal timing for the first stage ("remediation of line 41") in options 4-6. Since this is a lower cost option, it is optimal for it to be carried out earlier than assumed by the parties. My analysis suggests that, with some reasonable assumptions, option 6 comes out as the preferred option overall.

However, these methodological issues are relatively minor compared to the other assumptions adopted by the parties – specifically, assumptions relating to the rate of increase of demand, the rate of decline of reliability of the network, and the average value of congestion (the "Value of Customer Reliability"). These issues are discussed further below.

5. Modelling of outages

As noted earlier, a key driver in the Powering Sydney's Future program is the unreliability of the existing network – particularly the underground cables. Therefore the results hinge strongly on the modelling of the reliability of network.

The parties approach to modelling network reliability is summarised in section A.3 of the RIT-T document. The formula used to model failure rates is (in my understanding) standard in the industry. However, the output of the model depends strongly on certain key parameters (known as beta and lambda). I cannot comment on whether or not the parties have chosen these parameters correctly.

The parties have modelled three sources of failure:

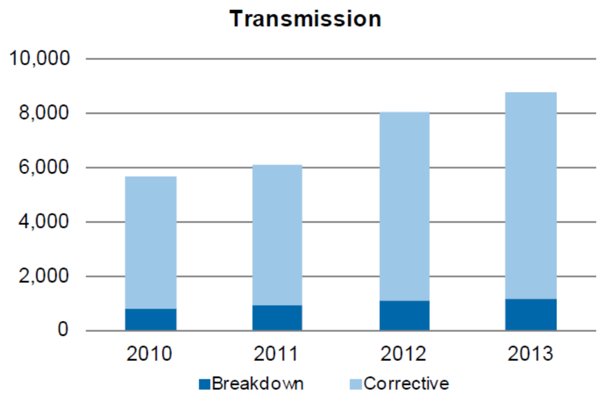
- Corrective actions
- Failure (breakdown)
- Third-party damage

"Third-party damage" refers to outages caused by third-parties (such as construction of buildings or other networks such as gas or telecommunications networks which damage the underground cables, giving rise to a forced outage). This number is relatively small and I will not consider it further.

The primary issue is the handling of "correction actions". What exactly do we mean by "corrective actions"? An Ausgrid document[3] sets out a graph of "breakdown" and "corrective" failures for distribution and transmission. The graph for transmission is shown here below.

[3] Ausgrid, Attachment 5.24, "Overview of the Replacement and Duty of Care Plans for 2014-19", May 2014.

Figure 10 – Breakdown and corrective failures for 2010-2013 for transmission



From this graph we can see that there are roughly 6-8 times as many corrective failures as breakdowns. But what exactly is a corrective failure? The footnote to this graph states that:

> "The **correctives** show the number of conditional issues identified during maintenance and addressed prior to failure, thus preventing a breakdown. The **breakdowns** show the number of issues that, despite a well developed and implemented maintenance program, went through to full failure."

My interpretation of this is that corrective failures are issues that are identified from inspection and are addressed *prior to a "full failure"* – that is prior to an involuntary outage on the cable. A corrective failure may (possibly) involve taking the cable out of service for some period of time for repair or maintenance, but, if so, the outage would presumably be planned. It is not good business practice to take an outage at a time when doing so will result in load shedding. In my view we can assume that the parties will strictly avoid the risk of load shedding arising from a planned network outage. All planned outages will occur when there is virtually no risk of any load shedding.

> **In other words, I suggest that corrective failures are incidents which are resolved without any loss of load, or without any need to take actions to manage congestion.**

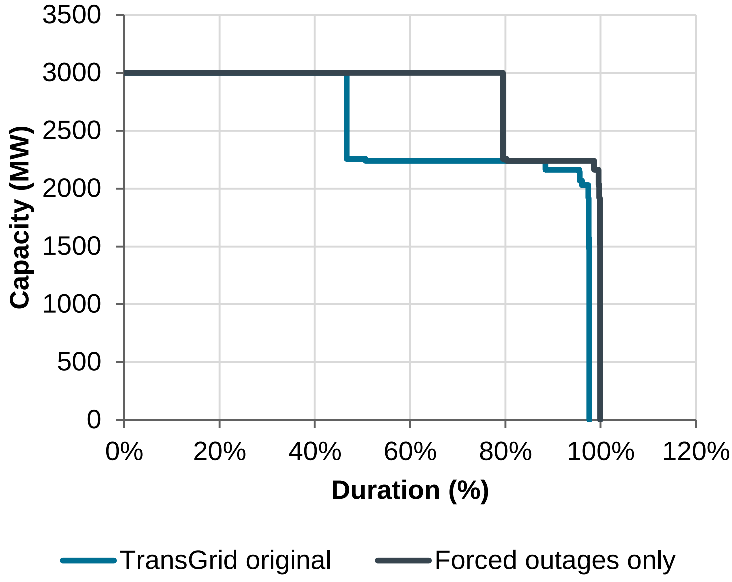
This is an important observation. As we have noted earlier, the PSF options are justified entirely on the basis of their impact on the congestion cost. If there is no congestion, there is no benefit.

For the purposes of the modelling congestion costs we are not interested in modelling the number of incidents on the cable, or the modelling of incidents which lead to the cable being taken out of service – we are only interested in modelling of incidents which lead to the cable being taken out of service in an unplanned, involuntary manner, resulting in congestion (or load shedding).

In my view we should not include "corrective actions" in the reliability modelling for the purposes of estimating the congestion cost.

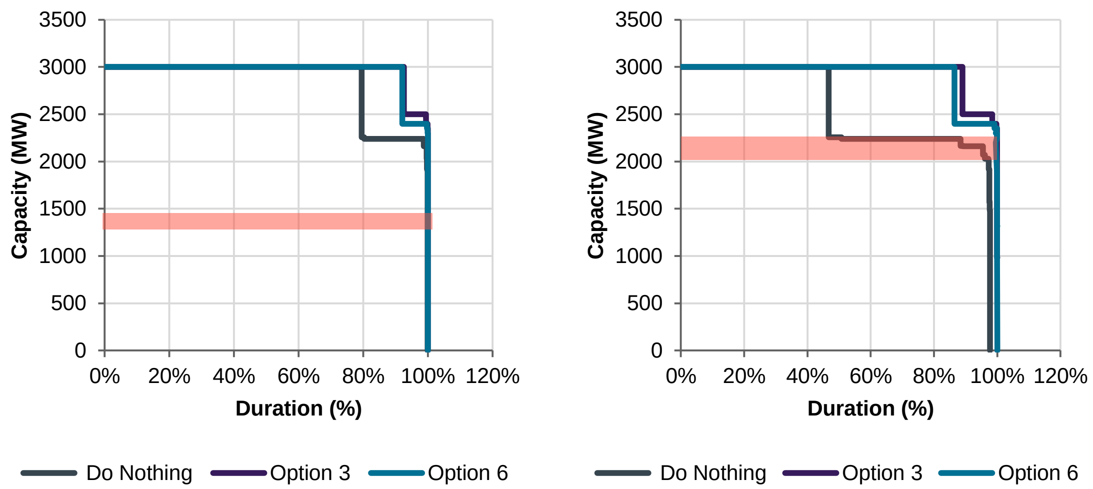
This makes a major difference to the modelling. The following diagram shows the estimated capacity-duration curve for 2015/16 for the central Sydney network under the original assumptions and the assumption that only forced (i.e., unplanned) outages are taken into account. As can be seen the network delivers a much higher level of reliability (and the modelling sums to very near 100 per cent).

Figure 9: Impact of changing reliability assumptions (Do nothing option, 2015/16)



The following diagrams illustrate the effect of considering only forced outages on the do-nothing option, option 3 and option 6. As can be seen, even with the parties' forecast of demand, if we focus only on forced outages the amount of unserved energy is likely to be much lower in 2035/36.

Figure 10: Forced outages only 2015/16 (left) and 2035/36 (right)



This change results in a substantial reduction in the estimated unserved energy and congestion cost. This can be seen in Figure 911 The impact of removing the corrective actions from the analysis reduces the estimated congestion cost in the "do nothing" option by a factor of about seven.

Figure 11: Congestion cost with and without corrective actions

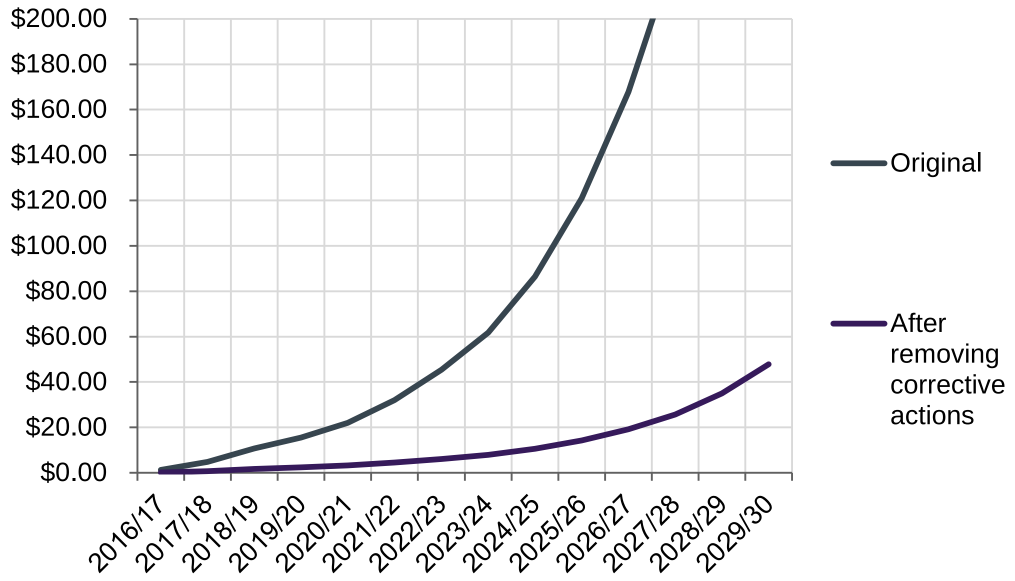


Table 6: Unserved energy and congestion cost (forced outages only)

Option		2016/17	2026/27	2036/37
Do nothing	Lost load (MWh)	1.4	203.9	3989.1
	Cost ($m/yr)	0.13	$19.15	$410.04
Option 3	Lost load (MWh)	0.0	1.3	270.9
	Cost ($m/yr)	$0.0	$0.15	$26.69

This significant reduction in the congestion cost has several important consequences for the analysis of the options in the PSF project. In particular, the very large reduction in the congestion cost pushes back the optimal time to undertake the various options. As the following table shows, just this change alone pushes back the optimal start time for the projects outside the next regulatory period (and possibly outside the regulatory period after that).

Option	First stage	Original timing	New timing (excluding corrective actions)	Deferral
1	New 330 kV, retire line 41	2020/21	2027/28	7 years
2	New 330 kV, line 41 at 132 kV	2020/21	2028/29	8 years
3	Two new 330 kV, retire 41	2022/23	2028/29	6 years

6. Modelling of demand

The rate of growth of demand

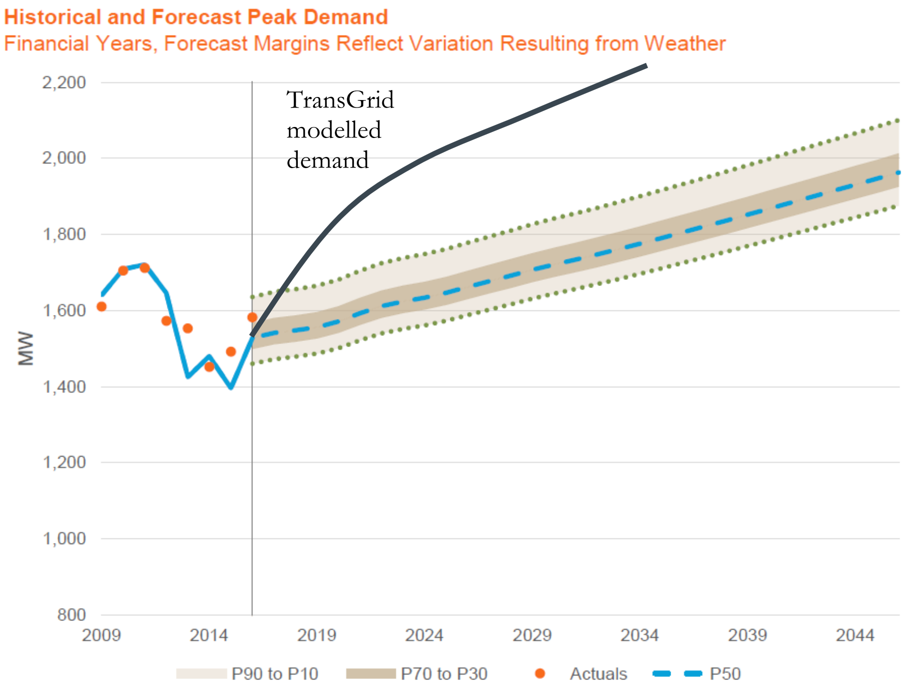
Another key driver of the congestion cost is the forecast of future demand. The more rapidly demand is forecast to increase the more rapid is the forecast increase in congestion cost.

As noted earlier, the parties' approach to modelling demand was to take the actual network load profile from 2013/14 FY and to scale this according to a forecast growth rate.

Importantly, the parties have chosen to scale peak demand at a rate which is very high – higher even than the advice the parties received from their advisors. The "RIT-T: Project Specification Consultation Report" includes, as an attachment, an "Energy and Demand Assessment" by BIS Shrapnel. In that report BIS Shrapnel predict that demand in central Sydney will grow at a rate of 0.9 per cent per year out to 2046, as illustrated in the diagram below.

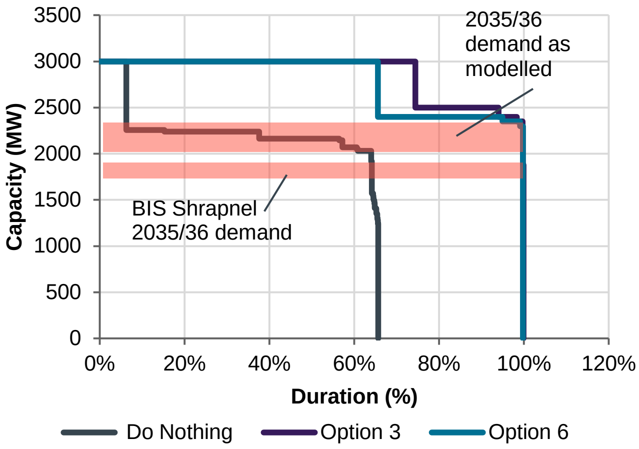
However, the demand forecasts used in the modelling predict that demand will grow considerably faster than forecast by BIS Shrapnel. In particular, the parties assume that (in the "medium" demand growth scenario) demand will grow by 5-6% in the first few years, declining to 1.5 per cent growth in the long run. This has a substantial impact on the long-term growth forecast. This can be seen in the diagram below. This diagram is taken from the BIS Shrapnel report. The superimposed solid curve indicates the demand path assumed by the parties in the modelling:

Figure 12: BIS Shrapnel demand forecasts with modelling assumptions superimposed



This increase in forecast demand has a very material impact on the forecast congestion cost. Under the BIS Shrapnel demand forecasts, even maintaining the original (unrealistic) reliability estimates, we would not expect that unserved energy would become a major problem until beyond the end of the 30 year BIS Shrapnel modelling horizon.

Figure 13: TransGrid capacity-duration curve 2035/36 with revised demand



In the RIT-T Project Specification Consultation Report the parties explain that this "base" forecast did not take into account forecast changes in the network architecture:

> "Adjustments to the base forecast are necessary to correct for planned changes to the network architecture such as load transfers and any planned new customer connections which have not been included in the base forecast. In the 2016 forecast, adjustments to the development forecast for the Inner Sydney area amounted to 229 MW by 2023 driven by significant network load transfers and major new customer load" (page 24).

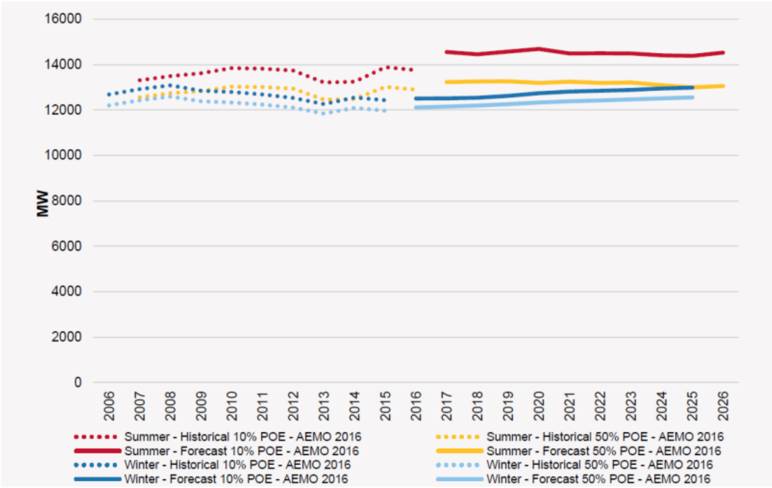
The report identifies load transfers associated with the retirement of the Arncliffe 33/11 kV and Blakehurst 33/11 kV substations. In addition:

> "The largest impact to the near term development forecast is due to a number of significant planned customer connections which total 190 MW by 2023".

However, even if we add in the full adjustment of 229 MW by 2023, this does not explain why the parties' modelling includes a faster rate of growth (around 1.5% per annum compared with 0.9% assumed by BIS Shrapnel). As far as I can tell the RIT-T report is silent on this point. If we add 229 MW to the BIS Shrapnel forecasts we find that the load is not forecast to exceed 2200 MW (the point at which network reliability becomes a serious issue) until well after 2035/36 (i.e., around twenty years in the future).

Is the BIS Shrapnel forecast of 0.9% per annum load growth reasonable? In its 2016 National Electricity Forecasting Report, AEMO forecast essentially *no growth* in POE10 peak demand for NSW for the next 20 years(!) (forecast POE10 demand for NSW is 14,200 MW in 2016/17 and 14,100 MW in 2035/36). This is illustrated in the following diagram:

Figure 1 AEMO's aggregated, non-coincident 2016 forecasts (including direct-connect loads)



However this forecast is for NSW as a whole. Perhaps the forecast for the Sydney region could be higher?

Interestingly, the AEMO 2016 forecast for the "Sydney Region" Connection Point 10-year summer POE10 growth rate is even lower – forecasting a decline of 0.8% per year over the next ten years.[4]

The BIS Shrapnel forecast is for just the "Inner Sydney" region. It is plausible that this will have a slightly higher growth rate than for the Sydney region as a whole due to growth in inner-city apartments, and the lack of facility for investment in solar PV (which suppresses demand growth elsewhere). It is also plausible that some of the recent decline in electricity consumption is due to the recent strong increase in electricity prices, which are forecast to moderate in the next few years. This could contribute to some short-term rebound in electricity demand growth.

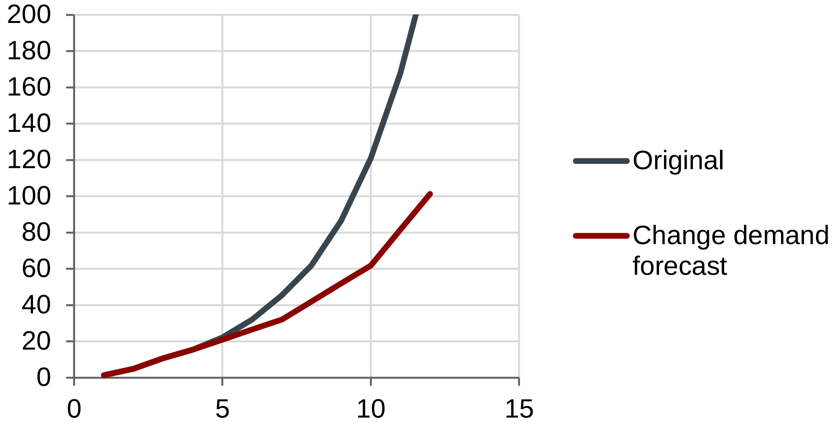
In this light, in my view the BIS Shrapnel estimates are at the upper end of a reasonable range of long-term growth estimates for inner Sydney (in my view, a reasonable range is 0-1 per cent over 30-40 years).

How much difference would changing the demand forecasts make? It is not possible to say exactly without reproducing the sophisticated calculations carried out in the modelling. However, the following graph estimates how the congestion cost might increase over time if we (a) allow for a large short term increase in the inner Sydney load due to load transfers and new customer connections, coupled with (b) a longer term growth rate of 0.9%.

As before, this lower forecast of congestion cost would likely have the effect of delaying some projects, possibly into the next regulatory period.

[4] AEMO 2016 Transmission Connection Point Forecasting Report, July 2016, Figure 5.

Figure 14: Impact of lower demand forecast on congestion cost



The profile of peak demand

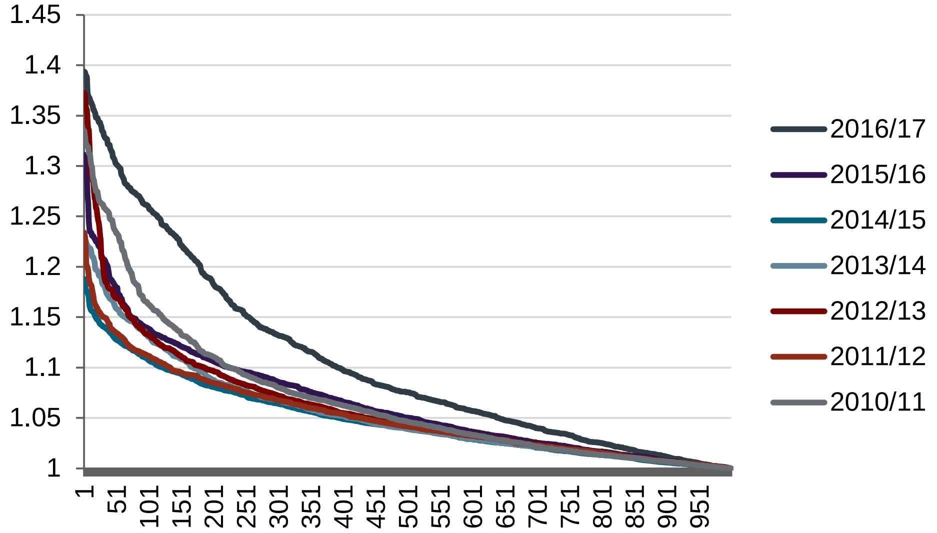
There is another issue in the demand forecasts used by the parties. The parties have chosen to model demand using the out-turn demand for the 2013/14 FY. However, in 2013/14 the load duration curve was rather "flat" in the upper end of the curve. This can be seen in the diagram below. Figure 15 shows the top 500 hours of load (with the 500th hour normalised to 1.0). 2013/14 had relatively flat load compared to other years.

In principle it is not correct to use the out-turn load profile of a single year. Instead, the modelling should reflect *all* possible load profiles that may occur. In some years the demand will be *much* higher (above the POE10 level), but with a low probability. In some years demand will be lower. The selection of the load profile in any one year cannot represent the range of possibilities that could occur in all future years. In my view the "top end" of the load profile should be much steeper than the parties have assumed, reflecting the potential for exceptional weather conditions.

The impact of the parties' modelling assumption is that the modelling is likely to detect load-shedding later than it will in fact occur (with some probability), and the load-shedding is likely to increase faster year-on-year.

In my view this is not a serious flaw in the parties' modelling, but probably should be addressed in future modelling exercises.

Figure 15: Load-duration curve NSW top 500 hours, various years



Uncertainty in demand and real options issues

There is another issue worth mentioning. The parties have considered a range of upgrade options, including staged options with the stages occurring at different times. As noted above, the timing of the stages was (in most cases) chosen to correspond to the economically-optimal time.

But there is one further consideration. In the presence of uncertainty about the future, it does not necessarily make sense to make all the decisions concerning an option (the stages, and the timing of each stage) at the outset. Instead, it may make economic sense to *defer* some decisions into the future, when we will have better information about market conditions.

In other words, in carrying out an option, we must not only consider how to stage the option, and when to implement each stage – we must also consider the potential to revise or update the project plan in the future. In the presence of sunk investments and uncertainty about the future the option to change, modify, or abandon a project plan can have considerable value.

In the present situation there is substantial uncertainty about future demand for electricity in central Sydney. Over the past decade we have seen demand in central Sydney both increase and decrease. The future path for demand depends on factors such as population growth, energy intensity, energy prices, and weather patterns. As we have seen, AEMO forecasts a wide range of future scenarios, and there is substantial disagreement in demand forecasts between AEMO, BIS Shrapnel and the parties.

In this context, the modelling should take into account the ability to update or change the project plan over time.

What impact would this likely have? Without carrying out the full modelling exercise we might guess that these considerations would have the following effect:

- It would be optimal to start each project later – as we noted earlier, a network upgrade only makes economic sense when the savings in congestion cost outweighs the annualised cost. If demand is uncertain, there is a risk that once we commit to the project demand will drop in the future, reducing the congestion cost. If demand is uncertain it makes sense to wait until the savings in congestion cost well exceeds the annualised cost of the upgrade before committing to invest.

- Projects which are carried out in stages (with a smaller commitment at each stage) would have greater value. By breaking the project into stages, each stage can be carried out at the appropriate time, while retaining the option to scale back or cancel the remaining stages if demand falls in the future. This yields greater expected value at the outset than committing to a large project, which leads to substantial over-capacity if demand falls in the future.

7. Modelling of the average cost of congestion

As noted earlier, in their modelling the parties have modelled the congestion cost as, in effect, an average cost of congestion multiplied by the amount of load reduction required. The parties have used a relatively high estimate of the average cost of congestion (also known as the Value of Customer Reliability). Specifically, they have assumed an economic cost of $170,000 /MWh for the Sydney CBD and $90,000/MWh for the Sydney Inner Metropolitan Area.

As a point of comparison, these values can be compared to the Market Price Cap (MPC) in the wholesale electricity market of $14,000/MWh. The wholesale electricity market is designed to allow supply and demand to be balanced in all except the most exceptional conditions. The fact that the MPC is $14,000/MWh shows that there is a general belief that a price of $14,000/MWh or less is sufficient to balance supply and demand at almost all times – to induce all market participants to make efficient usage and investment decisions. It is therefore worth exploring why the parties estimate that the economic harm from congestion in the Sydney region is up to more than ten times this level.

The economic harm from congestion depends on both short-run and long-run decisions. In the short-run, when rationing of scarce network capacity is required, in principle that rationing should be carried out as efficiently as possible. This means making efficient use of customer-side devices and appliances or other local generation. In the longer run, customers should have an opportunity to make any necessary efficient investments (in local generation, energy management systems, etc.) in response to on-going congestion before a commitment is made to a network upgrade.

In principle, we can achieve efficient rationing through price signals. At times of limited network capacity into inner Sydney the wholesale price should be allowed to rise to the point where supply and demand are balanced. The relevant congestion cost should be measured *as the level of the market price necessary to balance supply and demand each time congestion occurs and after all end-customers and market participants have had an opportunity to adjust their own devices and appliances to the varying prices reflecting varying network congestion conditions*.

It is no doubt true a complete cessation of supply to central Sydney would result in the loss of substantial economic value. Major cities (especially the CBD) tend to be a substantial focus of economic activity which could be severely disrupted by a loss of electricity supply. However, at the same time, inner city areas, with a high population density and a high density of economic activity also tend to have a substantial potential for building energy management systems and local energy storage and back-up generation facilities (indeed, it is precisely due to the high cost of supply interruption that end-customers invest in such systems). Even though the economic disruption from a total elimination of supply would be substantial, many inner-city buildings have the potential to manage their energy consumption, at least temporarily. This may be achieved through, for example:

- thermal inertia (pre-cooling or pre-heating, or allowing some adjustment of the heating or cooling in response to wholesale market conditions);
- local energy storage facilities (battery back-up, uninterruptible power supplies);
- local generation.

The relevant measure of the congestion cost is not necessarily the economic harm that would arise from a complete cessation of supply (which would be an upper bound) but, rather, the prices at which end-customers have an incentive to *use* local alternatives to the grid; and the prices at which end-customers have an incentive to *invest* in local alternatives to the grid.

Therefore we should ask the following:

- For those customers who have these facilities installed, such as air-conditioning controls, battery storage, or local generation, would they be induced to use them before the wholesale price increased to $90,000/MWh (metropolitan) or $170,000/MWh (CBD)? For example, at what point would the operator of an energy management system start to curtail air-conditioning load? When the wholesale price reaches ten times its normal level (around $1000/MWh), one hundred times its normal level (around $10,000/MWh) or around one thousand times its normal level (around $100,000/MWh)?

  In the event of congestion on the network serving inner Sydney, the (hypothetical) wholesale price for the inner Sydney region would increase sufficient to a point necessary to balance supply and demand. That price is the correct measure of congestion. It is difficult to say in the absence of actually implementing the required market conditions how high the price would go. However we can guess that the price at which supply and demand would balance might be more than the MPC ($14,000/MWh) but would likely be substantially less than $170,000/MWh. If this is the case the VCR estimate of $170,000/MWh is a substantial over-estimate.
- Similarly, in a long-run equilibrium would customers be induced to invest in end-customer facilities (energy-management systems, battery back-up etc.)? For example, it might be the case that 2 hours per year of pricing at $40,000/MWh is sufficient to induce end-customers in the centre of Sydney to invest in battery-back-up facilities. If this is the case, the VCR estimate of $170,000/MWh is a substantial over-estimate.

In my view the parties have materially over-stated the economic harm arising from congestion in the Sydney region. It is very difficult to know what the actual measure of harm is, since it depends on the market response to high prices. However we will not know unless we establish a mechanism for allowing balancing of supply and demand within the inner Sydney region in the event of congestion. It seems to me that a first step, before considering a network upgrade, is to consider a mechanism for efficient rationing of the available scarce capacity.

Under the National Electricity Rules, distributors – such as Ausgrid – are required to engage in cost-reflective pricing. It therefore makes sense to assume that distributors like Ausgrid exhaust the potential for cost-reflective pricing before considering a network upgrade.

In the analysis above we observed that a reduction in the forecast congestion cost has a very material impact on the optimal timing of the upgrade options and the selection of the desirable upgrade option. If mechanisms could be adopted to efficiently ration congestion it seems highly likely that the costs of congestion could be as much as an order of magnitude smaller than estimated in the modelling by the parties. As observed earlier, this has a substantial impact on the efficient timing of the upgrade options and the efficient choice of upgrade option. At the least, this would almost certainly defer the need for consideration of upgrade options into the next regulatory period.

8. Conclusion

TransGrid and Ausgrid have carried out very extensive spreadsheet modelling in support of its "Powering Sydney's Future" proposals. The spreadsheets I have examined are very sophisticated and capture many important elements of the decision as to when and how to upgrade a transmission network.

However, in my view the modelling by the parties could be improved in several ways. Specifically, in my view, the modelling could be improved by:

- Ensuring that the timing of each stage of each option is based on a comparison of the cost with the *change* in congestion cost, not just a comparison with the do nothing option as it is now.
- Capping the congestion cost in the more distant future at a reasonable level, to reflect the fact that a high congestion cost is not credible (as it would attract further action at that time).
- Reconsidering the inclusion of "corrective actions" in the modelled unreliability. My understanding is that corrective actions are actions which are taken to *prevent* an involuntary or forced outage. Corrective actions, by definition, do not give rise to forced outages. The should be excluded from the reliability modelling.
- Reconsider the high forecast demand growth. Growth in demand for electricity has moderated around the world. It remains to be seen when growth will return. The BIS Shrapnel forecast of 0.9 per cent per annum is at the upper end of the range. It is not clear why the parties have modelled long-run growth in central Sydney at 1.5 per cent per annum.
- Explicitly take into account the implications of demand uncertainty. Specifically model the potential to reconsider the timing and staged network options in the future. I would expect that this would substantially increase the value of staged network options.
- Carefully consider mechanisms to efficiently ration congestion when it arises.
- Reconsider the assumptions about the high average cost of congestion, especially in the light of opportunities for efficient ration of congestion.
- Reconsider the use of 2013/14 demand as a base year for the demand forecasts. In principle the demand modelling should reflect a full range of possible demand outcomes (appropriately discounted by probability) which cannot be captured in the demand forecasts for any single year.

In my view, if these changes are made the likely impact would be a substantial reduction in the estimated congestion cost in the short term, which will result in the proposed projects being efficiently deferred into the future – at least into the next regulatory period, and possibly the one after that. In my view, in the short term (i.e., in this regulatory period) the parties should focus on developing mechanisms for efficient rationing of scarce network capacity so as to be in a better position to estimate congestion costs in the future.

Darryl Biggar

23 May 2017