EnergyAustralia

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Dear David

Coalpac Consolidation Project

EnergyAustralia welcomes the opportunity to make a submission to the New South Wales Department of Planning and Infrastructure in support of the Coalpac Consolidation Project.

The importance of the Project

EnergyAustralia is a major participant in the NSW energy sector, with over 1.3 million electricity and natural gas customers in the State. To support our customers' demand for energy, we operate a portfolio of electricity generation assets in NSW. This includes the 435 MW gas-fired, Tallawarra power station, which we commissioned in 2009. It also includes the 2400 MW Delta West Gentrader bundle, Mt Piper and Wallerawang Power stations, which we acquired in 2011 after the sale process with the New South Wales Government.

Under the Gentrader agreement, EnergyAustralia has the right to trade the output from the power stations in the National Electricity Market. Mt Piper is the newest and most energy and emissions efficient power station of NSW's fleet of baseload coal-fired generators.

Under the Gentrader agreement we are also responsible for fuel supply to the power stations. At the time of the sale, a long term coal supply agreement with Coalpac was in place for Delta West until 2029. With the Coalpac resource located close to the power stations – indeed, the abundant, proximate coal resources are why the power stations were built in the area in the first place – this agreement provides a local, secure and low cost supply of fuel to Delta West, shielded from influences of the coal export market.

Electricity prices in NSW – and Australia more generally – have increased significantly in recent years. This has impacted the NSW economy via the impact on industry and impacted costs for residential consumers of electricity. Allowing the Project to proceed is therefore an opportunity to enable low cost, local coal resources of Coalpac to be utilised in the efficient, lower emissions Mt Piper Power station. This combination will provide benefits for the NSW electricity market and consumers over coming decades.

The initial Planning Assessment Commission report

EnergyAustralia does not support the findings of the initial Planning Assessment Commission (PAC) review. In particular, we consider that the review did not fully recognise the economic importance of the Project to the NSW power market. To explore this, we commissioned economic consultancy, Frontier Economics, to undertake an independent review of the initial PAC report, focusing on its findings in relation to the NSW electricity market.

Frontier Economics has identified a number of issues with the report. In particular, it found that it did not fully appreciate the workings of the NSW power market or the operation of the power stations, took into account information from questionable sources at the expense of recognised authorities on the energy market, and understated the economic importance of the Project to the power market. We submit the Frontier Economics report for the Department's consideration and at Attachment 1 provide a summary of Frontier Economics' findings.

Potential implications if the Project does not proceed

If the Project does not proceed, Delta West will lose a long term, secure, low cost coal supply. This will have impacts and flow on effects for the power stations, the NSW electricity market and NSW electricity consumers.

There are a range of factors that will determine how the market responds to the absence of Coalpac coal. These factors include whether and where alternative coal can be sourced; the price and availability of any replacement coal; the impact on the power stations' costs and running schedules; and the impact on wholesale and retail prices.

Given the myriad of factors, we have commissioned two independent analyses to provide insight into the range of possible outcomes.

The first piece of analysis was by coal and gas specialists, Wood Mackenzie. This commercially sensitive report examined Delta West's coal supply position, the alternative coal supply sources available to Delta West if Coalpac is not approved and the implications for price and availability of coal. The key findings of the Wood Mackenzie report are that:

- Coalpac is a critical supplier, representing 60-70% of the Mt Piper fuel supply;
- that the existing infrastructure linking Mt Piper and Wallerawang mean that the power stations are supplied by a single coal portfolio, with options for diverting fuel supplies between the two;
- that alternative coal supply options in the area are limited in the short to medium term and that sourcing coal from northern coal fields requires significant infrastructure upgrades;
- the price of coal supply without Coalpac will rise substantially given the influence of export markets; and
- that even at higher coal prices, without Coalpac, coal supply to Mt Piper is not guaranteed given the published intentions to redivert production from existing suppliers to supply export markets.

The Wood Mackenzie report confirms the importance of the Project to the Delta West power stations. Due to the commercially sensitive material in this report, this particular report is provided to the Department of Planning on a strictly confidential basis.

Electricity price modelling

To complement this coal supply analysis, we commissioned electricity market modelling specialist, ACIL Tasman, to provide independent electricity market modelling of the potential implications for the wholesale NSW electricity market should Coalpac coal not be available.

To capture the uncertainty in the market's response, ACIL Tasman's modelling approach was to compare a Base Case – a scenario where Coalpac is approved – with two scenarios capturing either end of the spectrum of what could happen if Coalpac is unavailable. The scenarios align with earlier modelling that we provided to the Planning Assessment Commission review – one scenario which we modelled internally and a second scenario that was externally modelled (also by ACIL Tasman).

ACIL Tasman has remodelled these two scenarios on a consistent basis using their latest assessment of the electricity market to span the range of plausible outcomes. The Wood Mackenzie analysis of coal prices was fed into the ACIL Tasman modelling to provide consistency between these two reports.

Potential price implications

ACIL Tasman's modelling found that without Coalpac coal, the increase in fuel supply costs and potential difficulties in replacing coal volumes means that over the next decade wholesale prices would likely increase. The magnitude of the price increases relative to the Base Case varies across the scenarios. In the low scenario, the increases range between 6% and 20%. In the high scenario, the wholesale price increase range from 6% to up to 29% higher than if Coalpac were available.

These wholesale price increases could translate into 4% to 12% retail price increases, depending on the type of customer – large commercial and industrial, small business or residential – and whether the contract is market based or regulated.

An alternative way to express the impact on customers is the reduction in consumer surplus, or conversely, the increase in the aggregate cost to consumers of purchasing wholesale energy. The modelling shows an increase in aggregate cost over the next decade of $5.5bn in the low scenario and $10.5bn in the high (or $3.8 bn to $6.1 bn in present value terms).

Attachment 2 describes in more detail the role of Coalpac and Delta West in the NSW power market, the potential impacts on the electricity market if the project does not proceed and the findings of the Wood Mackenzie and ACIL Tasman analyses.

The ACIL Tasman report is also submitted for the Department's consideration.

Summary

EnergyAustralia, as a significant user of fuel in the region, is committed to work with the state of NSW and regional stakeholders to ensure cost effective, sustainable, healthy mining operations and with it local power production, which continues to provide a benefit to the region.

We support the Coalpac Consolidation project. It provides the most favourable option for the supply of coal to Delta West. With NSW energy prices – both electricity and gas – expected to continue increasing (and this has been compounded by recent decisions that limit opportunities for gas resources to be developed in the State), the Project will support the stability of the NSW energy market and provide NSW electricity consumers with the opportunity to access the benefits of a local, secure, low cost source of energy.

We once again thank the Department for the opportunity to provide a submission and would be happy to meet to discuss any aspect. If you would like more information, please do not hesitate to contact me on 03 8628 1465 or mark.collette@energyaustralia.com.au.

Regards

Mark Collette
Group Executive Manager Energy Markets

ATTACHMENT A

Review of the initial Planning Assessment Commission report

The initial review by the Planning Assessment Commission was unsupportive of the Project. Of particular concern to EnergyAustralia was that the report made a number of comments and findings regarding the NSW electricity market which, in our view, did not fully appreciate the workings of the NSW power market or the economic importance of the Project.

We therefore engaged economic consultancy, Frontier Economics, to undertake an independent review of the initial Planning Assessment Commission report. The key findings of the Frontier Economics review in response to the PAC report are summarised in the table below. The full report is also attached.

PAC report finding	Frontier Economics comment
The PAC Report suggests that it is inappropriate to use world parity price of coal to estimate the value of the project.	*Even if Coalpac coal is not suitable for export, it is a substitute for export coal and there is an opportunity cost (value foregone) if export coal is diverted to Mt Piper Power Station. The actual Coalpac price does not reflect its economic value, as the price reflects the division of economic surplus between producers and consumers (including end consumers of electricity). A lower price reflects a larger benefit to consumers.*
The PAC Report suggests that additional coal for electricity generation is not required as demand for electricity in NSW is falling.	*Recent publications from Commonwealth Treasury and the Australian Energy Market Operator project continued growth in electricity demand, and supply from black coal fired generation, over the next 20 years. Further, even if demand did fall considerably, Mt Piper, as one of the most efficient power stations would still be required.*
The PAC Report is concerned with the causal link drawn between the withdrawal of Mt Piper Power Station from the National Electricity Market (NEM) and forecast wholesale pool price increases.	*This causal link is explained by showing how the withdrawal of a low cost generator from the wholesale electricity market results in higher pool prices because it is replaced by higher cost generation (and this price increase can be non-linear).*
The PAC raises specific concern about the impact of including Wallerawang (WPS) in the electricity market modelling.	*The fuel supply to MPPS and WPS would be managed as part of a portfolio and hence the modelling results of MPPS and WPS shouldn't be considered independently/in isolation. The fact that other coal may be diverted from WPS to MPPS (as the more efficient plant) does not sever the causal link between reduced supply from Coalpac and the resulting increase in electricity prices.*
The PAC suggests that the electricity market modelling should have accounted for changes in other factors, such as the behaviour of other generators or changes to network regulation which may outweigh the benefits arising from the Coalpac planning approval.	*The correct approach is to consider the counterfactual scenario all else being equal; the impact of these other factors should not be used to discount/offset benefits of the project. The benefits of any regulatory reform that delivers network cost savings and the benefits from the approval of the Coalpac project are not mutually exclusive. Any potential gains from changes to network regulations would be equally attainable irrespective of the approval of the Coalpac project.*
The PAC report states that there is not a short-term crisis as there is one year's worth of Coalpac coal stockpiled when current Coalpac deliveries cease.	*Alternative coal supply options would require new infrastructure investment, and subsequently long-lead times. As such, this could be considered a short-term crisis.*

ATTACHMENT B

The importance of the Coalpac Consolidation Project

In this Attachment we describe the NSW power market and the potential impacts and flow on effects for the NSW electricity market and NSW electricity consumers if Coalpac coal is not available. The results of two independent analyses that were commissioned to provide insight into the range of possible outcomes – by Wood Mackenzie and Frontier Economics – are also discussed.

The role of Coalpac coal and Delta West in the NSW power market

Delta West generators

In 2011, EnergyAustralia entered into a Gentrader Agreement (GTA) with the NSW Government for the Delta West power stations – Mt Piper and Wallerawang. Under the GTA, EnergyAustralia owns the rights to the output of the stations, while Delta Electricity continues to own and operate the physical power stations. Both Mt Piper and Wallerawang have two units each.

As one of the baseload NSW power stations Mt Piper is: the fourth largest and the most energy efficient of the coal fleet; has the lowest emission intensity, meaning it can produce the same amount of power as the State's other baseload coal power stations with less emissions and carbon cost to the state; and is 10-20 years earlier into its working life than the other power stations.[1] Wallerawang is a smaller, older plant.

Mt Piper has two electricity generating turbines, or units (700MW each), as does Wallerawang (500 MW each). Both stations supply their output to the NSW wholesale market, which is a region with the National Electricity Market.

Box 1: the National Electricity Market (NEM)

The New South Wales wholesale electricity market is part of the National Electricity Market (NEM) along with Queensland, South Australia, Victoria, Tasmania and the ACT. The NEM is the longest interconnected wholesale electricity market in the world.

The NEM is made up of supply (generators) and demand (retailers and other customers). Generators participate in the wholesale pool; retailers buy energy from the pool and then onsell to final customers.

The NEM operates like an auction that is run every five minutes, with the lowest bids winning. All generators bid in their energy each 5 minutes. The Australian Energy Market Operator dispatches generators from lowest to highest cost until demand is met. The 'Trading Price' is then the half-hour average of the 5 minute dispatch intervals and the generator gets paid according to how much energy it produced in that half-hour trading interval.

The wholesale market is a mandatory, gross, energy only market. This means all generators must sell their energy into it and they only get paid for the energy they produce (i.e. they are not paid for being available to generate, as is the case in other markets). This means generators are in constant competition with each other to be dispatched. Generator bids generally reflect their short run costs (mainly the cost of fuel) but generators must also recover their fixed capital costs over time.

The NEM is the most volatile commodity market in the world; prices can fluctuate from negative $1000/MWh to $12,900/MWh. Over time wholesale prices in the NEM provide signals for new generation to be built and existing generators to retire.

[1] Energy Supply Association of Australia (size, age); AEMO 2012 Planning Studies - Technical Generator Data Summary, for energy and emissions efficiency, see: http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Assumptions-and-Inputs

Coalpac coal

Under the GTA, EnergyAustralia is also responsible for fuel supply. Delta West currently sources coal from a number of local mines that are linked to the power stations by conveyors and haul roads.

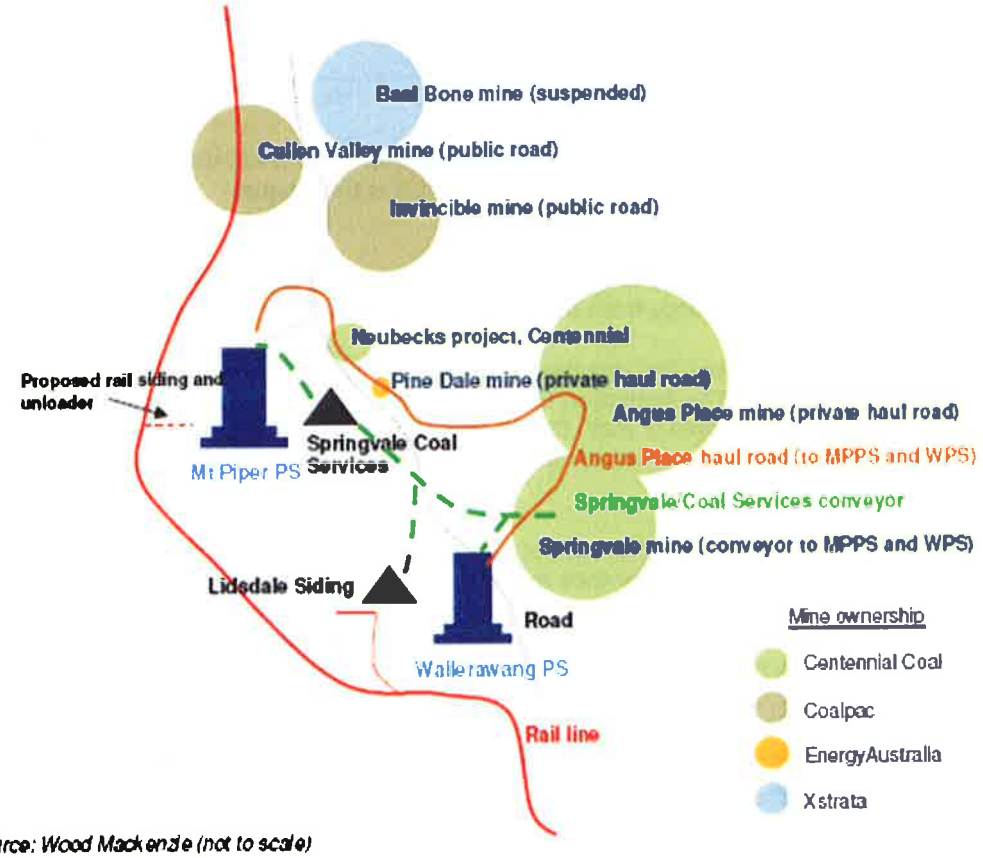
The chart below shows the coal supply infrastructure to Delta West. It shows that the existing infrastructure between the local mines allows coal to be transported via conveyor or private haul roads to either Mt Piper or Wallerawang.

As EnergyAustralia is responsible for fuel supply, this effectively means that coal supply to the four units of the Delta West bundle (2 units at Mt Piper, 2 units at Wallerawang) are supplied from a single coal portfolio. Fuel supply and power plant dispatch decisions are therefore made on an integrated basis.

We note that the initial PAC review does not acknowledge the real linkage between coal supply to Wallerawang and the Coalpac supply. Instead they have incorrectly concluded that because Coalpac coal is only supplied to Mt Piper, it cannot impact on Wallerawang. This is incorrect, as the other suppliers to these two power stations do have flexibility to deliver to both. The actual situation is therefore that removing Coalpac supply from Mt Piper does impact on outcomes at Wallerawang.

When the GTA was entered into, a long term coal supply agreement for 2.5 Mtpa was in place with Coalpac until 2029, which would see Coalpac supply about 60-70 per cent of Mt Piper fuel supply.

Chart: Delta West Coal Supply Infrastructure



Source: Wood Mackenzie (not to scale)

'Mine mouth coal' supplies

Given the long term coal supply agreement in place with Coalpac, Coalpac coal volumes are shielded from other influences, such as export markets.

Coal-fired electricity generators throughout NSW and the broader NEM have varying coal supply arrangements. Some generators, such as in Victoria, have captured brown coal mines located adjacent to the power stations (known as 'mine mouth' operations). These coal mines do not have any alternative uses such as export opportunities. As such, 'mine mouth' coal supplies are not linked to export prices and are lower.

In contrast, coal from mines that have physical or economic links to the export market are influenced by the export, or world, price of coal.

Because of the coal supply agreement between Coalpac and EnergyAustralia (via Delta), Coalpac coal is effectively a source of 'mine mouth' coal for NSW as the contracted volumes will directly feed the power station and do not have export opportunities.

Approval of the project therefore unlocks an advantage for NSW as it enables low cost, proximate coal resources of Coalpac to be utilised in the efficient, low emissions Mt Piper Power station. This combination will provide benefits for the NSW electricity market and consumers over coming decades.

Potential implications if the project does not proceed

If the project is not approved, Delta West will lose a long term, secure, low cost coal supply. This will have impacts and flow on effects for the power stations, the NSW electricity market and NSW electricity consumers.

There are a range of factors that will determine how the market responds to the absence of Coalpac coal. These factors include whether and where alternative coal can be sourced; the price and availability of any replacement coal; the impact on the power stations costs and running schedules; and the impact on wholesale and retail prices.

Given the myriad of factors, we have commissioned two independent analyses to provide insight into the range of possible outcomes.

Alternatives to Coalpac coal

The first piece of analysis was coal and gas specialists, Wood Mackenzie. Wood Mackenzie's report examined Delta West's coal supply position, alternative coal supply sources available options to Delta West if Coalpac is not approved and the implications for price and availability of coal.

Delta West's fuel supply position

Wood Mackenzie notes that the Coalpac mines are a key element of fuel supply security for the Delta West power stations going forward and that the Delta West coal catchment is significantly more limited compared with other NSW power stations.

- Unlike other NSW power stations, Delta West does not have access to rail infrastructure for coal deliveries and there are few opportunities for new sources of coal supply.

- Even with rail access, fuel supply security from other Western District mines is limited with most of these mines either suspended, exhausted, export focused, or requiring planning approval.

Influence of export markets

The report also examined the influence of export markets on the potential coal supply to Delta West. It noted that:

- in recent years coal suppliers to NSW generators with access to export infrastructure have stated publically that increasing export thermal coal prices has resulted in a growing disconnection from domestic prices, making exports more attractive.

- As a result of this, when long term contracts come up for renewal, or new contracts are negotiated, suppliers with an export option are expected to refer to export parity prices as a basis for their price position in the negotiation process.

Wood Mackenzie provided forecasts for increases in export thermal coal prices and the increased incentive they provide for coal producers to increase export volumes and if possible achieve export parity pricing in domestic contracts.

The report also noted that there is a strong push for local mines in the Delta West area to move increasing volumes of coal to the export market and reduce domestic supply. It found that should these export plans be realised, any surplus coal available for domestic use in the current coal catchment would rapidly decline with Delta West having to compete for coal which might otherwise be exported.

Alternative coal supplies from further afield

The report also explored the options of access to coal from the Ulan and Hunter coalfields in the north. It noted that:

- this would require a rail line upgrade between Gulgong and Kandos through Mudgee (estimated cost is $200m or more) and construction of a rail unloader (estimated cost is $150 or more), as well as necessary planning consents;

- that this option would not address the short term coal supply concerns given the time taken to undertake these works; and

- that coal pricing is expected to be significantly higher than that of Coalpac based on higher delivered cash costs.

Implications for Delta West fuel supply and pricing

Wood Mackenzie examined scenarios in the event that the Coalpac Consolidation project is not approved in terms of price and volume.

These scenarios show substantial increases in fuel input costs to Delta West. They also find that even at higher prices, should volumes of local coal be committed to the export market, Mt Piper Power Station could face a period where coal is not available to meet expected operations, given the lack of alternative suppliers.

In such a coal constrained environment, the report found it would be reasonable to expect optimisation of the Delta West's coal supply position through diversion of coal to Mt Piper, being the more efficient power station, using current coal transport infrastructure that allows coal to be delivered to either Delta West power station.

The impact on the power stations and the power market

The Wood Mackenzie report clearly establishes the importance of the Project to the Delta West power stations in terms of the price, timeliness and availability of coal supplies.

In order to understand the broader implications of the Project to the State's electricity market and consumers, we commissioned electricity modelling from industry experts, ACIL Tasman.

Electricity market modelling is a standard electricity industry approach for analysing the implications for wholesale markets and prices from economic and policy changes (see for instance, modelling commissioned by the Australian Treasury for the carbon price package[2]).

In EnergyAustralia's interactions with the initial Planning Assessment Commission review, we provided two sets of modelling results – one undertaken internally using an in-house model, and one externally developed (by ACIL Tasman).

However, the NSW Government subsequently announced the commencement of the NSW generator privatisation process. As EnergyAustralia is affected by that process and there was information in the modelling report that was commercially sensitive to that process, we formally withdrew the initial ACIL Tasman modelling from the review process as it was not appropriate for the public domain.

In this current set of ACIL Tasman modelling, we have commissioned ACIL Tasman to re-model these two scenarios on a consistent basis using their latest assessment of the electricity market to span the range of plausible outcomes. The Wood Mackenzie analysis of coal prices was fed into the ACIL Tasman model to provide consistency between these two reports. As commercially confidential material has been excluded the ACIL Tasman report is now suitable for the public domain.

To capture the uncertainty in the market's response, ACIL Tasman's modelling approach was to compare a Base Case – a scenario where Coalpac is approved – with two scenarios capturing either end of the spectrum of what could happen if Coalpac is unavailable. These two scenarios correspond to the two modelling scenarios that were provided to the initial PAC review and have now been modelled on a consistent basis.

ACIL Tasman periodically update their Base Case – that is, their house view of energy market conditions. The current modelling uses ACIL Tasman's up to date base case, which has been revised since the earlier set of modelling. The revisions reflect the carbon price outlook (a slight downward revision) and in particular, a view that gas prices will be higher in light of tightness in domestic gas markets[3]. The effect of the updated Base Case is higher expected Base Case prices, which results in lower increases due to the absence of Coalpac.

Scenario A: Coal price effects

The first scenario modelled by ACIL Tasman examined what would happen if, in the absence of Coalpac, Delta West could seamlessly source replacement coal from local mines at effectively unlimited volumes. For this scenario, the assumed price of this replacement coal was based on the Wood Mackenzie analysis of likely alternative coal supply costs in light of the influence of the export market. This is a reasonable representation of a 'best case' outcome.

The charts below show the projected increases in the NSW wholesale market compared to the base case.

In this scenario the modelling finds that due to the increased fuel cost, compared to the Base Case with Coalpac, the increased operating costs of the Delta West power stations sees Wallerawang no longer profitable to run on a normal schedule. Instead, it runs on a seasonal schedule for a few months of the year when prices are expected to be sufficiently high. As noted in the ACIL Tasman report, the economic response to increased coal prices would be to divert coal supplies to Mt Piper, the more efficient power station.

The charts show that in the Base Case (the blue line), prices are expected to fall once the fixed carbon price period ends and cheaper international permits can be purchased. Prices then rise from the middle of the decade due to increasing fuel costs.

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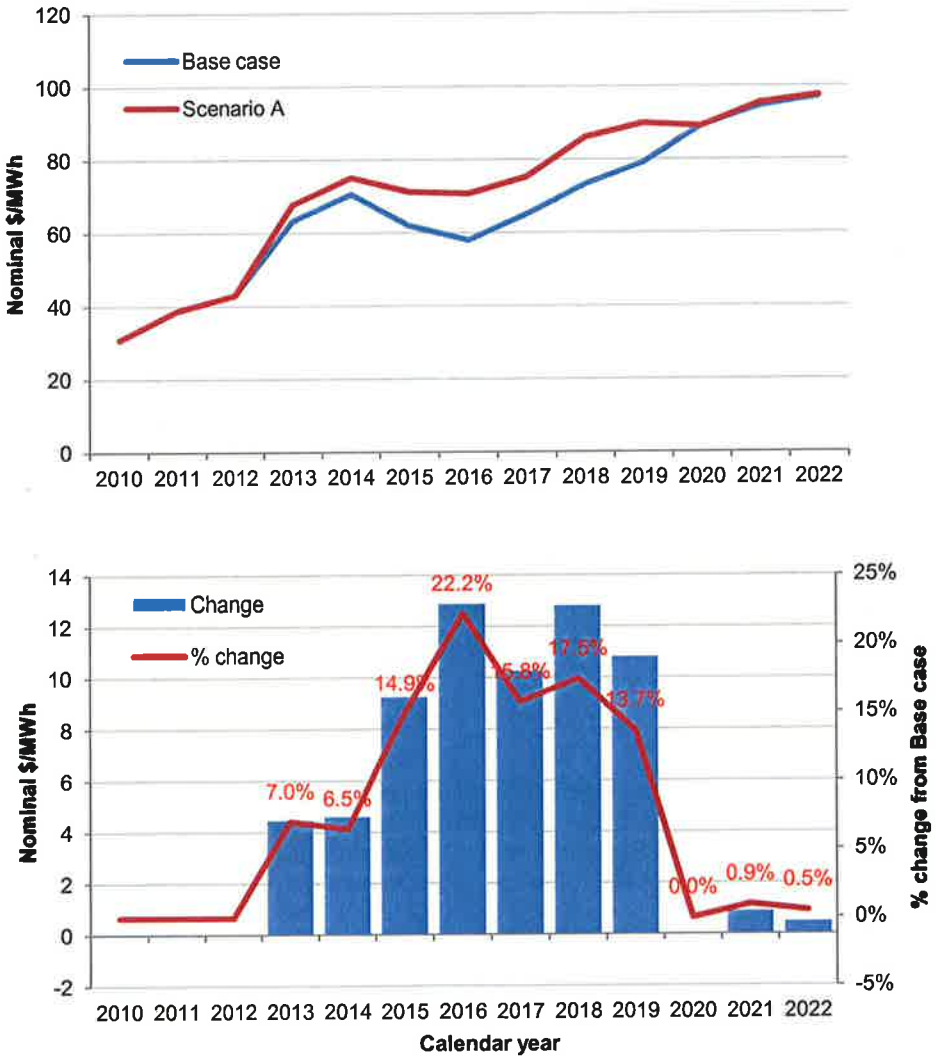
[2] See modelling by SKM-MMA and ROAM Consulting for the *Strong Growth, Low Pollution* report: http://carbonpricemodelling.treasury.gov.au/carbonpricemodelling/content/consultantreports.asp

[3] ACIL Tasman provide the gas price analysis for the Australian Energy Market Operator's National Transmission Network Development Plan 2012.

The red line (the 'best case'), shows that in the absence of Coalpac coal, prices rise more steeply through the rest of the decade. At their maximum, in 2016, they are 22% higher than otherwise. Prices are modelled to converge with base case prices by 2020, although it should be noted that the modelling assumes price rises are limited by perfect foresight and seamless new entry of generation capacity, which in reality may not occur.

Chart A: NSW wholesale electricity price (scenario A versus Base case)



Scenario B: Coal price and volume effects

The second scenario modelled by ACIL Tasman examined a situation with the same cost of replacement coal as per scenario A. In addition to this, it incorporates the situation identified by Wood Mackenzie where full replacement coal volumes are unable to be sourced locally due to local production being export bound. In this scenario, alternative coal supplies from northern coal fields are not an economic option in light of the necessary infrastructure investments (rail upgrade, construction of a coal unloader) and higher transport costs.

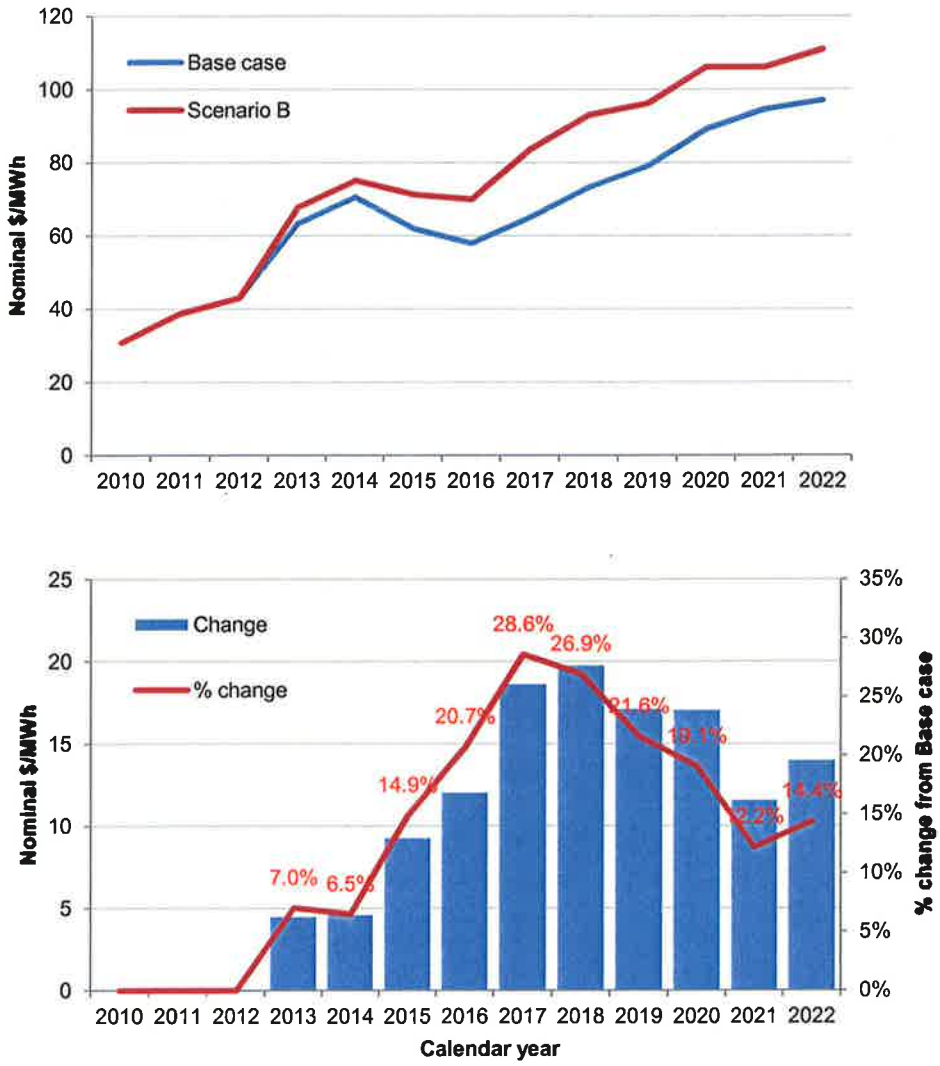
An additional difficulty with securing full replacement supplies from northern mines is the difficulty in entering take or pay contracts for the full volume of coal required. This is because of the risk that the higher coal price will make the Delta West stations uneconomic, reducing their dispatch in the NEM and hence their need for the coal

Together with scenario A, this scenario effectively provides the 'bookends' to the range of plausible outcomes.

The charts below show the projected increases in the NSW wholesale market compared to the base case.

In this scenario the modelling finds that due to the increased fuel cost, compared to the Base Case with Coalpac, the increased operating costs of the Delta West power stations sees Wallerawang no longer profitable to run at all and is retired. While coal is diverted to Mt Piper, its profitability also declines and one unit is closed. At their maximum, in 2017, prices are nearly 29% higher than the Base Case.

Chart B: NSW wholesale electricity price (scenario B versus Base case)



Impact on end consumers

There are two broad ways to measure the impact on end consumers of higher wholesale prices. Firstly, it is possible to calculate the reduction in consumer surplus, which is equivalent to the increase in the aggregate cost to consumers of purchasing wholesale energy. The modelling shows an increase in aggregate cost over the next decade of $5.5bn in the low scenario and $10.5 bn in the high (or $3.8 bn to $6.1 bn in present value terms).

Secondly, it is relevant to examine how these wholesale price increases would translate into retail price increases. The nature of the impact will depend on the type of customer – large commercial and industrial, small business or residential – and whether the contract is market based or regulated.

In general terms, retail electricity supply to large commercial and industrial customers – which make up more than half of NSW electricity consumption – will see wholesale price changes flow through to the retail bills of customers.

Similarly, for residential and small business customers on market contracts – which make up about 50% of the small customer market – wholesale prices will flow through to retail bills e.g. through changes to discount levels and other benefits, such as sign up bonuses.

For these customers with direct and indirect wholesale price exposure, retail price increase could be in the order of 4% to 12% in different years across the different scenarios. This is in addition to the projected price rises in the base case.

For small customers on regulated rates (around 50% of the small customer market) the flow through to retail prices will likely be lower under the current regulatory price setting. This is because the current approach to regulated pricing by the Independent Pricing and Regulatory Tribunal uses at least a long run marginal cost (LRMC) measure for 75% of the wholesale energy cost and 25% market based cost. Changes in wholesale energy costs will only be reflected in market based cost, not the LRMC measure.

Summary

The Coalpac Consolidation project provides the most favourable option for the supply of coal to Delta West.

If the project proceeds it will support the stability of the NSW energy market and allows NSW electricity consumers to access the benefits of a local, secure, low cost source of coal.

In contrast, if Coalpac coal is unavailable, the Delta West power stations will need to seek alternative coal supplies. Given the challenging coal supply conditions in the area and the influence of export markets, this presents challenges in terms of price and potential availability of coal. The potential results could be increases in wholesale electricity prices that flow into the prices paid by business and residential consumers.

Review of the NSW Planning Assessment Commission report on Coalpac

A REPORT PREPARED FOR ENERGYAUSTRALIA

February 2013

Review of the NSW Planning Assessment Commission report on Coalpac

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1 Overview

The NSW Planning Assessment Commission (PAC) released its report on the Coalpac Consolidation Project on 14 December 2012 (PAC Report). EnergyAustralia (formerly TruEnergy) has engaged Frontier Economics to review and comment on the content of the PAC Report, specifically on the issues that relate to the economic benefits of the project and the impacts on electricity markets.

Frontier Economics regularly conducts electricity market modelling using proprietary models, including for major market transactions (such as the Contract for Closure[1] and the NSW Gentrader projects) and for retail price determinations, such as in NSW for IPART[2]. This report does not undertake electricity market modelling of the impact of approval/disapproval of Coalpac, but instead focuses on the underlying economic principles and the intuition of previous electricity market modelling results and the PAC responses. Likewise, this report does not investigate or review the methodology or estimates provided by Gillespie Economics, or the alternative options for coal supply.

In our view, it appears that the PAC has misunderstood some of the arguments and modelling results previously put forward by EnergyAustralia/Coalpac as they relate to electricity market impacts and the potential benefits of the project. We have not reviewed those prior modelling results in detail but focus on the operation of electricity markets generally, and the likely impacts of limits to coal supply to Mt Piper (MPPS) due to rejection of planning approval for Coalpac.

In particular, we raise the following issues with the PAC report:

- The PAC Report suggests that it is inappropriate to use world parity price to estimate the value of the project. Even if Coalpac coal is not suitable for export, it is a substitute for export coal and there is an opportunity cost (value foregone) if export coal is diverted to MPPS. The actual Coalpac price does not reflect its economic value, as the price reflects the division of economic surplus between producers and consumers (including end consumers of electricity). A lower price reflects a larger benefit to consumers.
- The PAC Report suggests that additional coal for electricity generation is not required as demand for electricity in NSW is falling. However, recent publications from Commonwealth Treasury and the Australian Energy

1 http://www.ret.gov.au/energy/clean/contract/Pages/ContractforClosure.aspx

2 A complete CV and details of Frontier Economics' energy experience are available separately in Appendices A and B

Market Operator[3] project continued growth in electricity demand, and supply from black coal fired generation, over the next 20 years.

- The PAC Report is concerned with the causal link drawn between the withdrawal of MPPS from the National Electricity Market (NEM) and forecast wholesale pool price increases provided by EnergyAustralia. We explain this causal link by showing how the withdrawal of a low cost generator from the wholesale electricity market results in higher pool prices (and this price increase can be non-linear). We provide a real world example of pool price increases associated with the recent withdrawal of capacity in the National Electricity Market.
- The PAC raises specific concern about the impact of including Wallerawang (WPS) in the electricity market modelling. We discuss how the fuel supply to MPPS and WPS would be managed as part of a portfolio and hence the modelling results of MPPS and WPS shouldn't be considered independently/in isolation. The fact that other coal may be diverted from WPS to MPPS (as the more efficient plant) does not sever the causal link between reduced supply from Coalpac and the resulting increase in electricity prices.
- The PAC suggests that the electricity market modelling should have accounted for changes in other factors, such as the behaviour of other generators or changes to network regulation which may outweigh the benefits arising from the Coalpac planning approval. But the correct modelling approach is to consider the counterfactual scenario ***all else being equal***; the impact of these other factors should not be used to discount/offset benefits of the project. The benefits of any regulatory reform that delivers network cost savings and the benefits from the approval of the Coalpac project are not mutually exclusive. Any potential gains from changes to network regulations would be equally attainable irrespective of the approval of the Coalpac project.
- The PAC report states that EnergyAustralia is not facing a short-term crisis as they will have one year's worth of Coalpac coal stockpiled when their current Coalpac deliveries cease. We understand that alternative coal supply options would require new infrastructure investment, and subsequently long-lead times, and therefore discuss why this could be considered a short-term crisis.

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3 AEMO is the power system operator and the market operator, and is responsible for forecasting and planning in the electricity market (among other things).

2 Summary of main findings

The PAC summarised its findings on project benefits as follows:

PAC report, Exec Summary i

> The benefits claimed for the project are principally in the areas of employment (120 positions in total with 30 of these additional); engagement of contractors; wealth generation (claimed net benefits of $1,519 million); provision of a cheap source of coal for Mount Piper Power Station with flow on benefits for electricity prices; reduced traffic impacts in the local area (i.e. Cullen Bullen); and supply of building sand to western Sydney.
>
> The claimed benefits of the project are largely distributed away from the population bearing most of the impacts of the project. Of the existing mine employees, only 3% come from Cullen Bullen and it is not anticipated that the project will generate significant demand for housing or facilities in the area. The Commission has also found that claims associated with some of the benefits do not appear robust when examined closely. For example, the claimed $1,519 million net benefit is very sensitive to coal price fluctuations. A 20% decrease in the price at which the benefits were calculated decreases the net benefit by 42% to $881 million. The claimed net benefit was calculated using world parity prices (an accepted analytical approach), but the poor quality coal produced by the project is largely (70%) unsuitable for export and could never achieve the world parity price. In fact the long-term contracted price for the coal produced by the project is well below the export parity price.
>
> The claimed potential increases in wholesale and retail electricity prices if project coal is not supplied to Mount Piper Power Station (35% and 13% respectively) were examined carefully by the Commission including two sets of confidential supporting documentation provided by Energy Australia. The Commission found that, whilst there may be some (limited) impact on wholesale prices in the short-medium term, there was no credible evidence to support a causal relationship between increases in retail prices of the magnitude described and changes in part of the fuel supply to a single NSW power station. The modelling also failed to account for the majority of factors that would influence electricity prices over the period 2013-2022.

A summary of the main arguments from this are:

- The Coalpac coal is traded at less than the international price, largely due to its inferior quality (which would make export unviable). Though not explicit, this appears to suggest that the benefits of the project should be discounted as the coal is less valuable;
- With respect to electricity prices, the PAC suggests that the reported price increases projected in the modelling provided by EA are overstated. A key reason put forward by the PAC is that other factors (unrelated to the coal supply to MPPS) would place downward pressure on electricity prices, including falling demand and other regulatory measures to reduce electricity prices.

Table 1: Summary of PAC findings and Frontier Economics comments

PAC finding	Frontier Economics comments (summary)
The Commission has also found that claims associated with some of the benefits do not appear robust when examined closely. For example, the claimed $1,519 million net benefit is very sensitive to coal price fluctuations. A 20% decrease in the price at which the benefits were calculated decreases the net benefit by 42% to $881 million. The claimed net benefit was calculated using world parity prices (an accepted analytical approach), but the poor quality coal produced by the project is largely (70%) unsuitable for export and could never achieve the world parity price. In fact the long-term contracted price for the coal produced by the project is well below the export parity price. Coalpac coal is traded at less than the international price, and due to poorer quality is not suitable for export. PAC seems to suggest that this would reduce the net benefits of the project.	We have not reviewed the Gillespie Economics methodology, so cannot comment on the estimated net benefit of $1,519m. However, in principle, the fact that the Coalpac coal price is less than the international price does not reduce the economic benefit of the project. Even if Coalpac coal cannot be exported, it is a substitute for exported coal. This means that any consideration of the economic benefit of the project must consider the Coalpac coal against an alternative option and the cost (or price) of each is relevant. If the alternative coal supply options have export potential then the international price is relevant, regardless of whether Coalpac is lower quality/lower price. In terms of economic surplus, the benefit of a project is the difference between the **cost** of supply and the **value** of the product to end consumers. The price determines the distribution of benefits between producers and consumers - a lower price for Coalpac coal simply means that consumers of Coalpac coal (ultimately the electricity end-users) see more of the benefits than the coal producer. In this instance, this would mean electricity generators or consumers realise a higher benefit from the project.
The claimed potential increases in wholesale and retail electricity prices if project coal is not supplied to Mount Piper Power Station (35% and 13% respectively) were examined carefully by the Commission including two sets of confidential supporting documentation provided by Energy Australia. The Commission found that, whilst there may be some (limited) impact on wholesale prices in the short-medium term, there was no credible evidence to support a causal relationship between increases in retail prices of the magnitude described and changes in part of the fuel supply to a single NSW power station. The modelling also failed to account for the majority of factors that would influence electricity prices over the period 2013-2022.	There is recent evidence of similar wholesale electricity price increases (across the NEM) as a result of capacity withdrawals of similar size to MPPS, so the modelling results appear feasible on face value. The PAC points to other factors that may affect retail electricity prices. These relate to demand and changes in regulation that may reduce network costs. Firstly, benefits from network regulatory changes and Coalpac approval are not mutually exclusive: even if regulations were changed to reduce network costs, this does not diminish or offset the benefits of the Coalpac project. Secondly, credible projections from AEMO and Commonwealth Treasury suggest that electricity demand continue to grow, and that black coal generation will continue to be required.

3 The value of Coalpac coal

PAC finding

The PAC Report suggests that it is inappropriate to use the world parity price for coal when estimating the value of the project. The reasons provided are that the Coalpac coal is a lower quality / not suitable for export, and is already contracted for a price lower than world parity. For example:

PAC report, p139

> The Commission also notes that the world parity price of coal has been used in calculating the benefits of the project. This is noted in the peer review and justified on the basis that it 'recognises the scarcity value of the coal resource as is required in the analysis of economic efficiency'. However:
>
> - the coal to be supplied to MPPS is not suitable for export and world parity does not therefore appear to be particularly relevant;
> - the Proponent has a contract to supply around 70% of the product coal from the project to MPPS at a price substantially below current world parity;
> - this contract extends to 2029, which covers 17 of the 21 years of a possible approval for this project; and
> - the claimed threshold benefits of $1,519 million for the project are particularly sensitive to the coal price. A 20% reduction in coal price reduces the threshold benefits 42% to $881 million.

And:

PAC Report, p143

> - the substitute coal price used to calculate the impact on MPPS of loss of Coalpac coal is the world parity price. This is the worst-case scenario. It is based on market conditions in which all product coal suitable for export can find export markets and therefore there is no opportunity to negotiate lower-priced contracts for domestic supply. Given the geographical location of Delta West generators this may prove to be the case. However, as noted in the economic assessment for the EA 'there is great uncertainty around both the availability and price of alternative sources for MPPS'.

Frontier Economics comments: on opportunity cost

Detailed analysis of the Gillespie Economics methodology or the specific options for alternative coal supply to MPPS is beyond the scope of this report. However, in principal, even if Coalpac coal cannot be exported (due to lower quality) it is still a substitute product for exported coal. This means that any consideration of the economic benefit of the project must consider the Coalpac coal against an alternative option and the cost (or price) of each is relevant.

If alternate suppliers of coal were to divert resources from export to supply MPPS (at a price similar to Coalpac) then the coal supplier would incur an

"opportunity cost". The opportunity foregone is the export price (adjusting for transport, quality or washing costs. In this instance, the economic burden would fall on the alternate coal supplier (selling at a lower price).

Alternatively, if the alternate coal were supplied to MPPS at the export price (adjusted for transport cost, quality or washing cost) then MPPS would face a higher cost, which would be passed-through to electricity consumers. This is discussed in Section 4.

In principle it doesn't matter if Coalpac coal cannot be exported: the relevant consideration is the value of the alternate supply of coal. We do not comment specifically on the alternative options for coal supply in this report. However, as an example of evolving industry trends, in 2010, 27 of the total of 55 operating coal mines in New South Wales sold some or all of their production to domestic consumers. By contrast, only eight mines conveyed or trucked their entire outputs to adjacent power stations. Five of these eight had no access to port facilities, and the remaining three have now closed.

In the past, lower-quality by-product coal was frequently sold at prices close to production cost in the absence of any other market. This situation is now changing. Because of improved rail and port capacity, as well as emerging offshore markets for this material, mine operators are increasingly able to sell even sub-optimum product into export markets. While exceptions are certain to remain, it is likely that coal will increasingly be sold at prices based on export benchmarks discounted for lower energy and higher ash and water content. But this question is really beyond the scope of this report.

Frontier Economics comments: on value/economic surplus

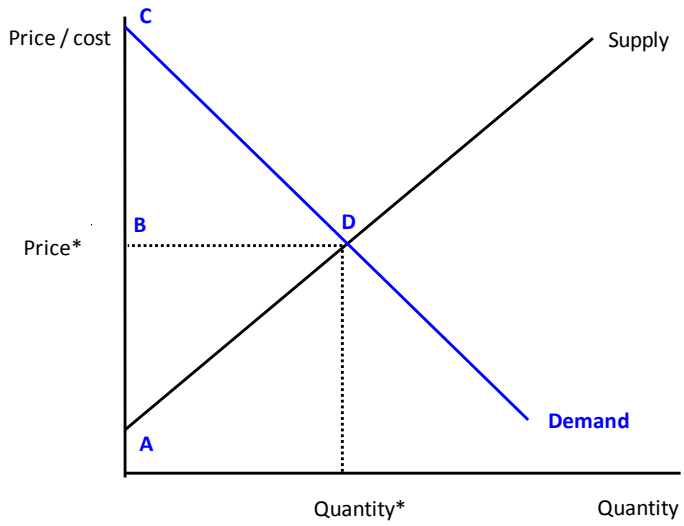
The PAC report seems to argue that, since Coalpac coal is low quality, it is low value and should be valued lower than export coal for the estimation of the economic benefit of the project. This argument is based on a false premise that the price of Coalpac coal reflects the economic benefit of the project.

The stylised example of economic theory (below) explains why this is incorrect. In terms of the standard definition of "economic surplus", the benefit of a project is the difference between the cost of supply and the value of the product to end consumers as reflected by their "willingness to pay". This is not necessarily the same as the price at which a good is traded. The price determines the distribution of benefits between producers and consumers; a lower price simply means that consumers realise more of the economic surplus than producers.

To explain this concept, Figure 1 presents a stylised supply and demand diagram of a homogenous good in a perfectly competitive market. The horizontal axis is the volume traded and the vertical axis is the price/cost per unit. Supply is typically upward sloped; indicating that it is more costly to produce higher

volumes of output. Demand is typically downward sloped; reflecting the theory that more consumers are willing to buy a good at lower prices. In a market exchange, such as a stock market for shares or a wholesale pool for electricity for example, a common price for all units sold will usually be set where demand and supply intersect. The "economic surplus" or value created from trade is the area between the curves (ACD): this reflects the degree to which the "willingness to pay" (the demand curve) is higher than the cost to produce (the supply curve). In this example – where all units trade at the same price – the consumer surplus, or what they gain from trading, is represented by the difference between their "willingness to pay" and the price they pay (BCD). Similarly, the producer surplus is the difference between production cost and the price earned (ABD).

Figure 1: Stylised example of supply, demand and economic surplus (market price)



Consumer surplus: CBD

Producer surplus: ABD

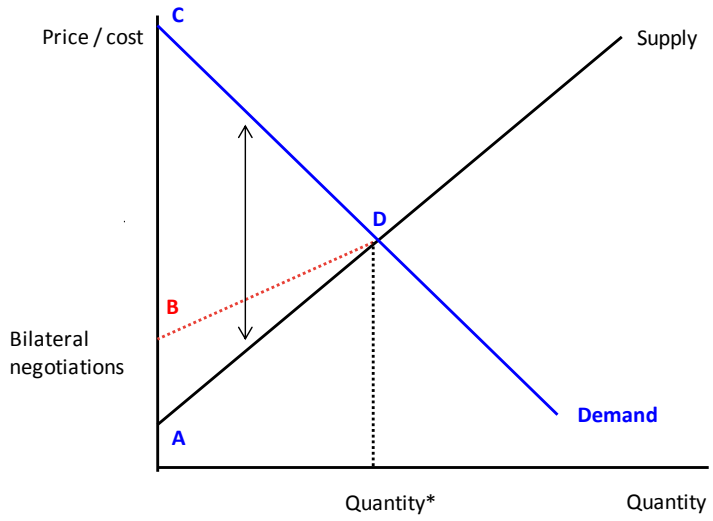
Economic surplus = Consumer + Producer surplus = ACD

Source: Frontier Economics

However, not all products need to trade at the same market clearing price for the same economic surplus to be realised. In some markets prices are set via bilateral negotiations, so it is standard for different prices to be set for each product traded. This is common for many international commodity markets. Figure 2 demonstrates an example where different prices are set for each product traded (the red line) based on bilateral negotiations. The red line reflects prices generally lower than in the previous example. In this example, the total economic surplus is exactly the same as in the example above, however the lower prices from bilateral negotiation means a greater share of the economic surplus is realised by consumers and a smaller share is realised by producers. This demonstrates that the PAC is incorrect to suggest that lower (long term) contracted prices for

Coalpac coal necessarily results in lower project benefits. It just means that consumers of Coalpac coal (electricity generators and ultimately electricity consumers) realise a greater share of the economic benefits delivered.

Figure 2: Stylised example of supply, demand and economic surplus(bilateral prices)



Consumer surplus: CBD

Producer surplus: ABD

Economic surplus = Consumer + Producer surplus = ACD

Source: Frontier Economics

Extension to electricity

The price of coal will also affect consumer and producer surplus in the downstream electricity market. The likely electricity market impacts are discussed in detail in the following section. In terms of economic surplus, since coal is an input into electricity generation, a lower cost of coal (fuel input) will generally result in a combination of (a) higher producer surplus (where the generator in question is not setting the price) and (b) higher consumer surplus (where the generator in question does affect the market price). The fact that coal is sold to electricity generation at a lower price than international parity means a greater economic value is realised by both the electricity generator and electricity consumers (in NSW and the national electricity market, NEM). In other words, the very fact that Coalpac coal is sold for a price lower than international parity is a source of higher economic surplus in the electricity market, as it contributes to lower electricity prices, and higher producer and consumer surplus in the electricity market. As a consequence, this surplus would be reduced if Coalpac coal had to be substituted for a higher cost source of supply. The PAC inference that the lower price of Coalpac coal necessarily reduces its economic value is incorrect on this basis.

4 Electricity market impacts

The PAC report also includes several findings related to the impact of the Coalpac development approval/rejection on electricity markets which we disagree with. This section summarises and addresses each of these points.

4.1 Electricity demand in NSW

PAC finding

The PAC Report states that the trend of falling demand for electricity in NSW is expected to continue. The implication seems to be that additional coal for electricity generation is not necessary if this is the case. For example:

PAC report, p139

> A number of issues are raised concerning the rationale for the project including inter alia the failure to recognize the declining trend in electricity consumption (particularly in NSW) which is at odds with the EA position which describes 'the inevitable increase in demand for electricity' as requiring increased production of thermal coal. A couple of points are relevant here.
>
> - the International Energy Agency (IEA) predicts that international energy demand will continue to rise largely driven by developing nations;
> - the Australian demand trend is downwards and this is particularly the case in NSW. This trend is not anticipated to change in the short-medium term; and
> - the majority of the coal from this project is poor quality coal not suitable for export. Only 1 Mtpa of the better quality coal is able to be exported and transport and market arrangements are not yet in place for this. Since over 70% of the annual production is for domestic use, the evidence does not support justification of this particular project by reference to increased energy demand.
>
> The Commission's conclusion is that, even though the economic analysis may be acceptable in theoretical terms, for this particular project it appears to grossly overstate the real financial benefits.

In making its findings, the PAC relies on statements in the UTS Institute for Sustainable Futures (UTS-ISF) submission that states that demand for coal is likely to decrease in the future:

UTS-ISF submission, p13

> Attention should also be drawn to fact that the total National Energy Market demand has been trending downwards since its peak in 2008, and specifically in NSW where it declined by 1.9 TWh (2.4%) from 2008 - 2011 (Nunn and Jander, 2012). This decline cannot be attributed to changes in the weather, but rather it has been suggested that this decline is due to the penetration of PV systems and solar water heaters, which have displaced around 1 TWh per year over this period in NSW (ibid).

In addition, the Australian Federal Government's "Clean Energy Plan is expected to cut pollution by a minimum of 5% below 2000 levels by 2020 and 80% by 2050, through a proposed transition to renewable and clean energy, energy efficiency and improved demand management (Commonwealth, 2012). This is likely to further decrease the demand for coal in future.

The market share of renewable energy will further increase as a result of economies of scale and the increasingly competitive prices of such energy sources (particularly as subsidies to the coal industry are removed or otherwise distributed equally amongst renewable energy sources), The consequence of all these factors is the decreasing demand for non renewable sources of energy over time.

Frontier Economics comments

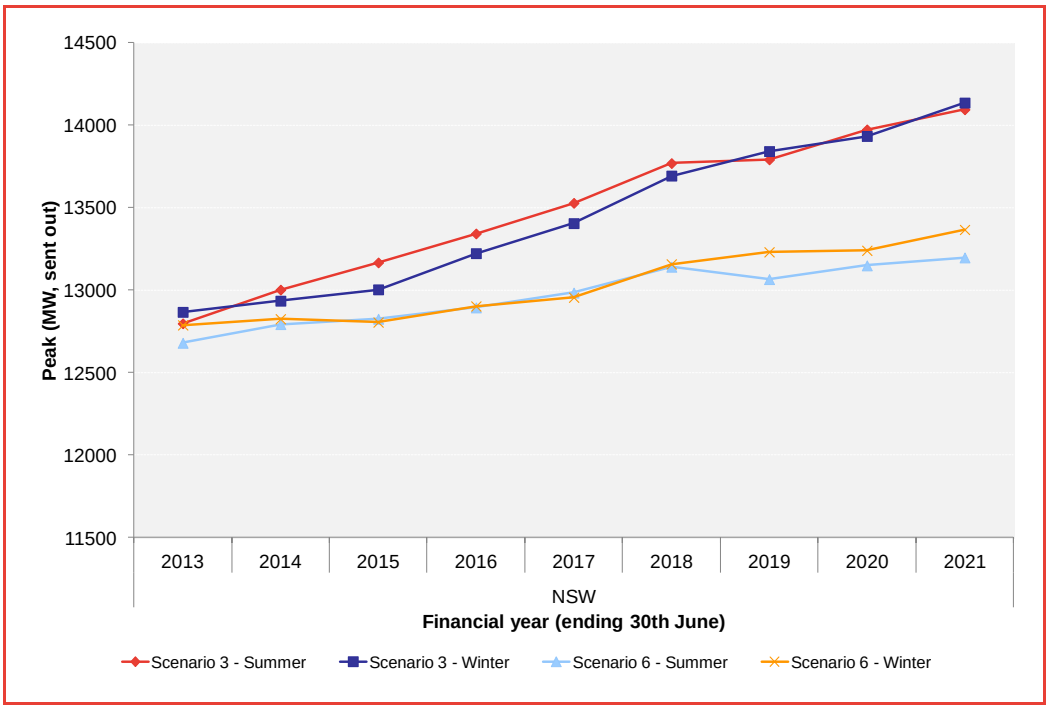
Firstly, it is not necessarily proven that electricity demand will continue to fall in NSW. A fall in demand in recent years has coincided with:

- the global financial crisis (GFC), which resulted in slow/falling economic activity generally;
- significant electricity price increases, mostly due to rising network costs that will not necessarily continue and a jump from the introduction of carbon; and
- policies targeting energy efficiency and distributed renewables (such as solar photovoltaic (PV)).

However, the most recent electricity demand projections released by the Australian Electricity Market Operator (AEMO)[4] do not support a conclusion that demand will continue to fall. AEMO's 2012 National Electricity Forecast Report (AEMO 2012 NEFR) has published an expected forecast for electricity demand to FY2021 (referred to as Scenario 3, Planning) in all NEM regions. Neither the peak nor energy forecasts follow a falling trend. Moreover, the AEMO 2012 NEFR forecast with the slowest rate of demand growth (Scenario 6, Slow Growth) also follows an increasing trend over the forecast period. These forecasts are illustrated in Figure 3 and Figure 4. These forecasts already account for increased output from solar PV and other renewables due to existing policies to support renewables.

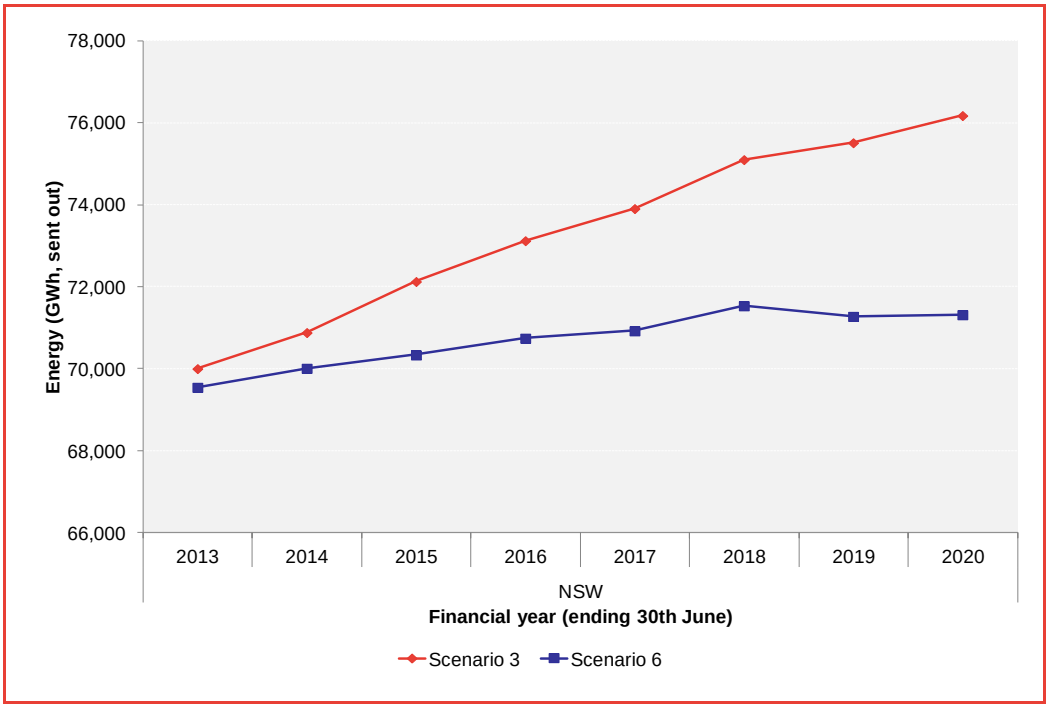
4 AEMO was established by the Council of Australian Governments (COAG) in 2009 to manage the national gas and electricity markets. It is the power system operator and the market operator, and is responsible for forecasting and planning in the electricity market (among other things).

Figure 3: NSW peak demand forecast



Source: AEMO 2012 NEFR

Figure 4: NSW annual energy forecast

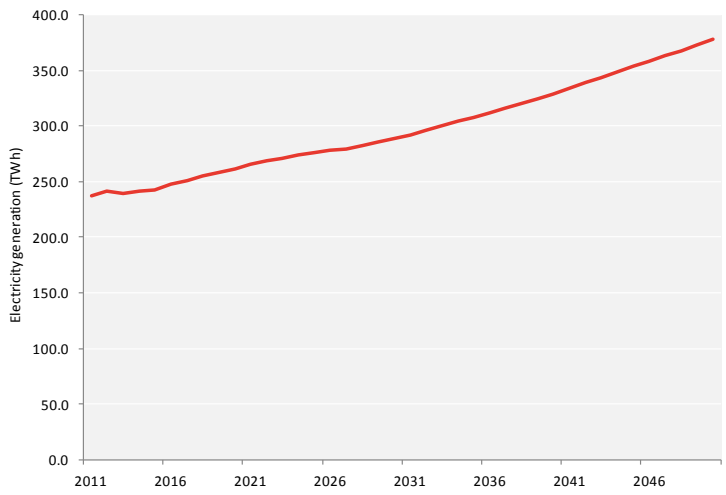


Source: AEMO 2012 NEFR

Secondly, the statements from the UTS-ISF submission that demand for coal is likely to decrease in the future are not substantiated. Comprehensive modelling of the electricity market was conducted by Commonwealth Treasury in the lead up to the introduction of a carbon price. We have reviewed the Commonwealth Treasury modelling projections of the impact of carbon on electricity markets on the basis that this is independent modelling unrelated to the Coalpac development. The modelling projects continuing growth in electricity demand. It also projects that supply from black coal generators will remain relatively stable or increase even with a carbon price that is significantly higher than current expectations and renewable support policies in place. This is mostly due to the sunk capital cost of existing coal projects: renewables may become viable to displace new thermal investments[5], but it would be far more costly to displace existing investments with sunk capital costs.

Figure 5 presents the Commonwealth Treasury electricity generation projections in the Government Policy scenario, which accounts for the introduction of a carbon price. This shows continued growth over time.

Figure 5: Australian electricity generation projections: Clean Energy Future modelling



"Government Policy" scenario. Actual generation is not reported for this scenario, but this is derived from Chart 4.11 (electricity sent out without carbon) and Chart 5.17 (change in electricity demand due to carbon)

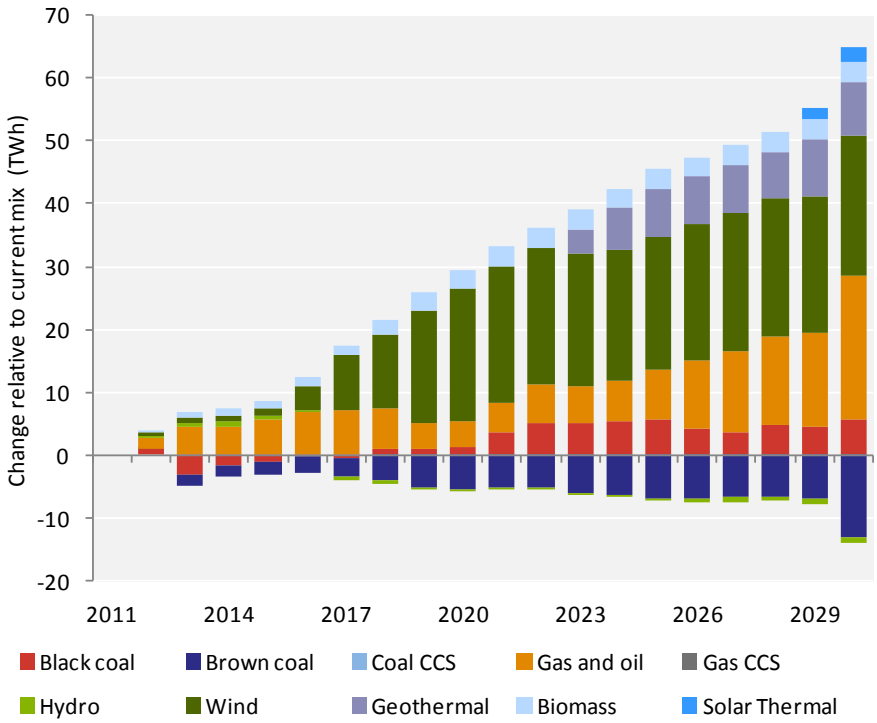
Source: Frontier Economics analysis of Strong Growth, Low Pollution - Modelling a Carbon Price, Commonwealth Treasury, 2011: http://archive.treasury.gov.au/carbonpricemodelling/content/chart_table_data/chapter5.asp

5 Even then, this potential to replace thermal capacity is limited to the extent that wind/solar are intermittent. For example, AEMO finds that wind can only around 2.2%-8.3% of wind capacity be relied on to contribute to peak demand (at the 85% percentile):

http://www.aemo.com.au/Electricity/Planning/Related-Information/Wind-Contribution-to--Peak-Demand

Figure 6 presents one set of Commonwealth Treasury projections of the change in generation mix relative to current levels. This set of results reflects the ROAM Consulting modelling results prepared for Treasury. The change is not reported by Treasury, but it can be calculated from the electricity projections and the generation mix (%) that is reported. Black coal continues to supply the market – and even increases supply - until 2030.

Figure 6: Australian electricity generation projections: Clean Energy Future modelling change in generation relative to current mix (ROAM)

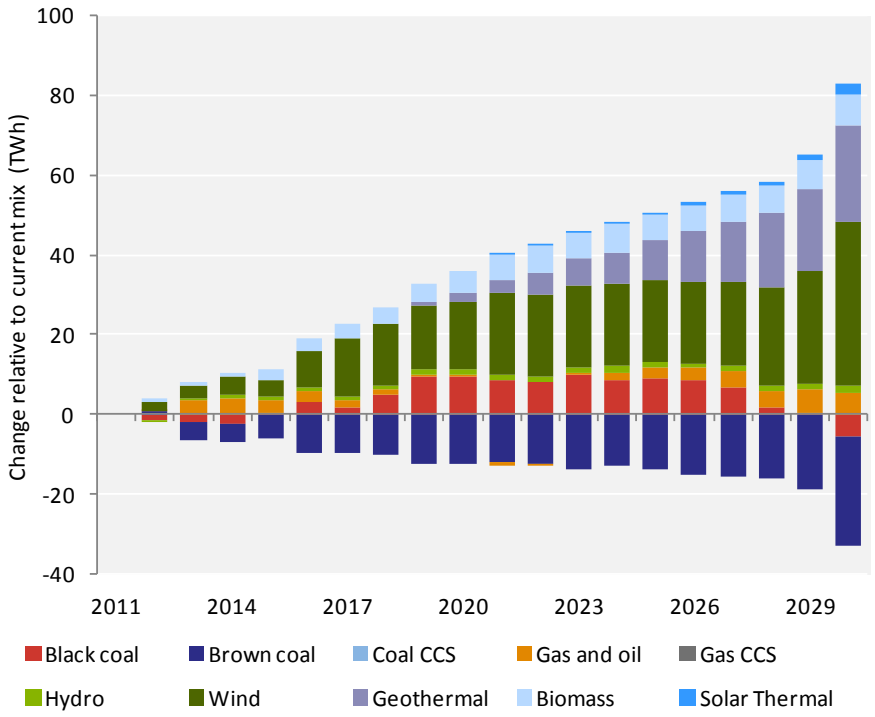


"Government Policy" scenario. Derived from Chart 4.11 (electricity sent out without carbon, in TWh) and Chart 5.17 (change in electricity demand due to carbon, in PJ), and Chart 5.19 (sources of electricity generation, in %)

Source: Frontier Economics analysis of Strong Growth, Low Pollution - Modelling a Carbon Price, Commonwealth Treasury, 2011:
http://archive.treasury.gov.au/carbonpricemodelling/content/chart_table_data/chapter5.asp

Figure 7 presents the same results as provided by SKM-MMA. This presents a very similar outcome. Both modelling results include a carbon price.

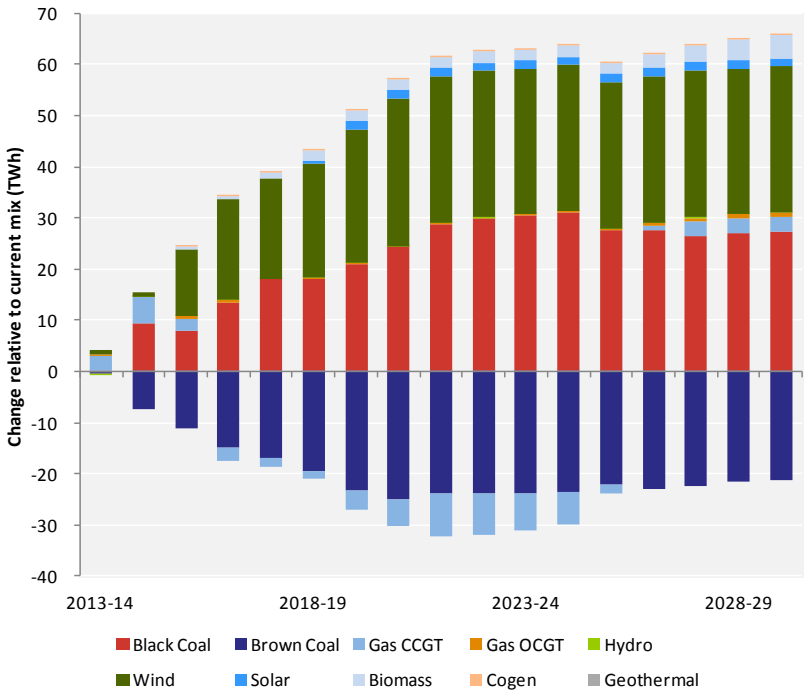
Figure 7: Australian electricity generation projections: Clean Energy Future modelling change in generation relative to current mix (SKM-MMA)



"Government Policy" scenario. Derived from Chart 4.11 (electricity sent out without carbon, in TWh) and Chart 5.17 (change in electricity demand due to carbon, in PJ), and Chart 5.19 (sources of electricity generation, in %)

Source: Frontier Economics analysis of Strong Growth, Low Pollution - Modelling a Carbon Price, Commonwealth Treasury, 2011: http://archive.treasury.gov.au/carbonpricemodelling/content/chart_table_data/chapter5.asp Another set of electricity market modelling conducted independently to the Coalpac development process is that reported by AEMO in the 2012 National Transmission Network Development Plan (NTNDP). Figure 8 presents the forecast change in the NEM wide generation mix relative to current levels for the "Planning scenario". Figure 8 shows an increase in supply from black coal generation until FY2025, at which point supply from black coal remains relatively constant until FY2030. This increase in black coal generation is primarily due to the combined impact of a moderate rate of demand growth, the increasing Renewable Energy Target and the carbon price, which results in a displacement of brown coal generation with black coal generation. The scale of the projected increase in black coal generation (around 30TWh by FY2025) is approximately the equivalent to two baseload coal generators of around 2000MW each.

Figure 8: Australian electricity generation projections: 2012 NTNDP Planning Scenario



Source: Frontier Economics analysis of NTNDP2012, AEMO
http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Detailed-Results

All three sets of independent modelling results contradict the assertions of the UTS-ISF submission and the PAC findings.

4.2 Electricity price impacts and the inclusion of WPS in the modelling

PAC finding:

The PAC appears sceptical about the potential electricity price impacts if the project does not proceed and MPPS is required to source more expensive coal from elsewhere. For example:

PAC Report – p141

8.6.3 Electricity Costs

8.6.3.1 Introduction

The issue that will dominate reporting on the outcome of this review will be the alleged increase in NSW wholesale and retail electricity prices if the project does not proceed. The headline figures claimed are:

- wholesale price increase of 35% by 2022; and
- retail price increase of 13% by 2022.

The Commission has examined this issue carefully. That examination casts substantial doubt on the claims.

The PAC raises specific concern about the impact of including Wallerawang (WPS) in the electricity market modelling, as this appears to be a cause of price increases. The PAC argues that this should be excluded from the consideration:

PAC Report – p141

8.6.3.2 Basis for the Claims

Scrutiny of the Energy Australia claims and the material supplied raised the question of whether the claimed increases in electricity prices were based on MPPS or on the whole of the Delta West generation capacity, which includes Wallerawang. Energy Australia confirmed that it was Delta West generation that was used to calculate the increases. This is important for a number of reasons:

- the Project Application is principally for supply of coal to MPPS, not to Wallerawang; there are factors other than coal price that will affect decisions on the longevity of Wallerawang; and

PAC Report, p143

8.6.3.3 Commission's Findings

- The claims that absence of Coalpac coal will cause major increases in NSW wholesale and retail electricity prices are not substantiated on the evidence presented.
- Although the claim in the TRUenergy submission on the EA is based on increased cost of coal to MPPS 'Increased costs would need to be reflected in the wholesale prices bid into the National Electricity Market by Mt Piper', questioning of Energy

Australia revealed that they are in fact based on changes to Delta West Generation as a whole (which includes Wallerawang).

PAC Report – p144

- Close scrutiny needs to be applied to any claims of price increases that include Wallerawang as a factor in the analysis. The project application is principally for supply of coal to MPPS, not to Wallerawang.

Frontier Economics comments

In our view, the correct modelling approach should compare a Base Case scenario where the Coalpac project proceeds and supplies MPPS against a counterfactual scenario where the Coalpac project does not proceed and MPPS sources its coal from alternative (more expensive) sources. Frontier Economics has not considered the specific alternative sources, or estimated the likely increase in coal costs. However, in our view, the fuel supply to MPPS and WPS would be managed as part of a portfolio and hence the modelling results of MPPS and WPS shouldn't be considered independently/in isolation. Firstly, the location of the plant and shared infrastructure would mean that coal would often be diverted between the plant. The fact that MPPS is the more efficient of the two would mean that, in the event of fuel supply shortages coal would preferably be directed toward MPPS, and WPS would be the first to close. As such, there would be a causal link between reduced fuel supply to MPPPS and the closure of WPS (if this was because WPS fuel was diverted to MPPS as the more efficient plant). The modelling approach adopted, as we understand it, reflects this ability to divert coal supply interchangeably to maximise efficiency.

If a strict division of fuel supply between MPPS and WPS were to be applied to test the market impact of rejecting Coalpac planning approval, then the approach to modelling should presumably be modified to reflect this strict definition. In other words, it would seem reasonable to assume that fuel could not be diverted between the two plant interchangeably. In that instance it would be seem likely that rejection of Coalpac approval would affect MPPS coal supply, coal supply would not be diverted from WPS and MPPS would be the first to close (and the resulting price impacts would reflect a clearer causal link).

In any case, economic theory suggests that the incremental effect on wholesale pool prices of MPPS reducing supply due to lack of viable coal supply options will be larger in the short-medium term if WPS also exits the market. In particular, it is due to the shape of the merit order/price duration curve, which is non-linear.

An illustration of this concept, without using actual numbers, is shown in the stylised example in Figure 9. It shows demand and four merit order curves:

- The red solid line reflects capacity/merit order with both MPPS and WPS included. This results in price P1 (found at the intersection of the supply/merit order curve and demand).

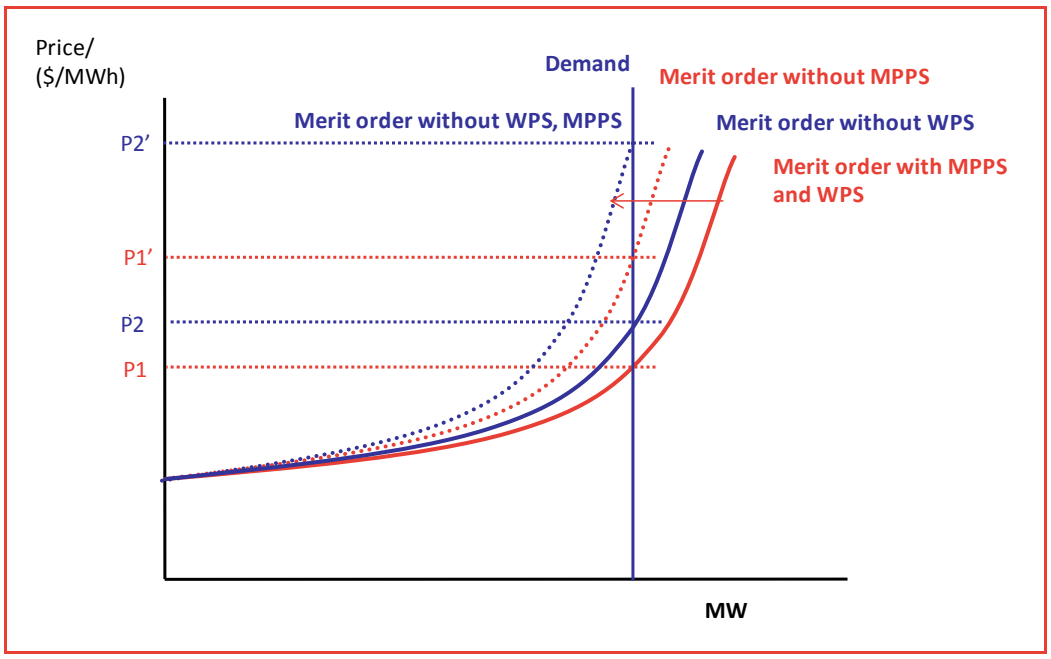
- The red dashed line reflects the impact of withdrawing just MPPS. This results in price increasing to P1'.
- The blue solid line reflects capacity/merit order with just WPS withdrawn. This results in price P2.
- The blue dashed line reflects the impact of withdrawing both MPPS and WPS. This results in price increasing to P2'.

The withdrawal of MPPS and WPS shortens the relatively flat region at the beginning of the merit order curve since this region is where the relatively cheap baseload coal generators are found. As each baseload generator is withdrawn, the steep section of the merit order curve shifts left.

As a result, there is more potential for steeply rising prices when capacity is withdrawn from the market in the short-medium term, hence the cumulative effect on price of withdrawing two generators should be more than the sum of withdrawing each individually. The withdrawal of one plant will leave prices at a steeper portion of the price duration curve. Figure 9 clearly shows this effect with the withdrawal of MPPS and WPS. The effect of withdrawing MPPS is larger if WPS is already withdrawn from the market, as the market will be on a steeper portion of the price duration curve: the relative increase from P2 – P2' is larger than the increase from P1-P1'.

This means that although price increases due to WPS withdrawal (in isolation) may not be relevant to the benefits test, the fact that it exacerbates price increases once MPPS is withdrawn is relevant to the benefits test.

Figure 9: Stylised example of withdrawing capacity for a given level of demand



Source: Frontier Economics

4.3 The causal link between MPPS closure and price increases post-2018

PAC finding

The PAC raised concerns regarding the robustness or veracity of the electricity market modelling. Specifically, this included the concern that the price impact was greater *after* MPPS ceased operations (post 2018). The PAC suggested that there is no causal link between these projected price increases and the withdrawal of MPPS (Delta West). The PAC seems to argue that these prices increases would have occurred with or without MPPS in the market, and that this is attributed to other factors in the market. The logic behind this argument is that, beyond 2018, the grid must source its supplies from power stations other than Delta West and therefore that price increases are not due to the cost increases incurred by MPPS.

PAC Report, p142

> The justification for the figures for cost increases is based on modelling the impact of increased coal prices to Delta West generators in the absence of coal from Coalpac. The model is a simple one that adjusts the position of these generators on the SRMC+ table and from this determines their likely dispatch rate given the projected demand. As profitability falls, a decision is made to retire Wallerawang in 2015 and MPPS in 2018, with all Delta west generation ceasing in June 2018.
>
> There are a number of concerns with the model:
>
> - it shows only a small increase in the NSW wholesale price (pool price) between 2013 and mid-2018 when the Delta West generation is said to cease. That increase is approximately 15%, which translates to 5% in retail prices;
>
> - there is then a steeper increase between mid-2018 and mid-2022, when NSW pool prices are said to be 35% higher. It is this higher figure that is used by Energy Australia to calculate the 13% retail impact.
>
> Energy Australia argued (teleconference 30/11/12) that there is a flow-on effect of the cessation of Delta West generation in the period 2018-2022 that causes this increase. However, the Commission's view is that, while the small increases projected to 2018 may have a relationship with coal price increases to MPPS there can be no direct relationship between Delta West generation and price increases in the 2018-2022 period. The 2018 base will have an element of cost increase due to Delta West cessation, but beyond that the grid must source its supplies from elsewhere and any increases are solely due to behaviour of the alternative suppliers. A claim that Delta West would have maintained existing prices in the face of increases by all other competitors in the market in the period 2018-2022 has not been made.
>
> The likelihood of market adjustment in the period 2013-2018 is also evident from the material supplied by Energy Australia. The decline in supply to the grid from Delta West occurs over the whole 2013-2018 period, which would indicate that alternative supply costs would be factored in gradually and be fully evident by 2018.

PAC Report, p143

8.6.3.3 Commission's Findings

- The claims that absence of Coalpac coal will cause major increases in NSW wholesale and retail electricity prices are not substantiated on the evidence presented.

- The case for a causal relationship between cessation of supply of Coalpac coal to MPPS in 2013 and any further increases in electricity prices beyond the 2018 price is not made out.

Frontier Economics comments

Economic theory would conclude that there is a direct causal link between withdrawal of capacity and the price increases post 2018. A simple "but-for" test would show that electricity prices would be lower between 2018-2022 if not for the withdrawal of MPPS from the market (due to a higher cost structure without Coalpac coal). It is not correct to say that MPPS can only impact prices while it is operating.

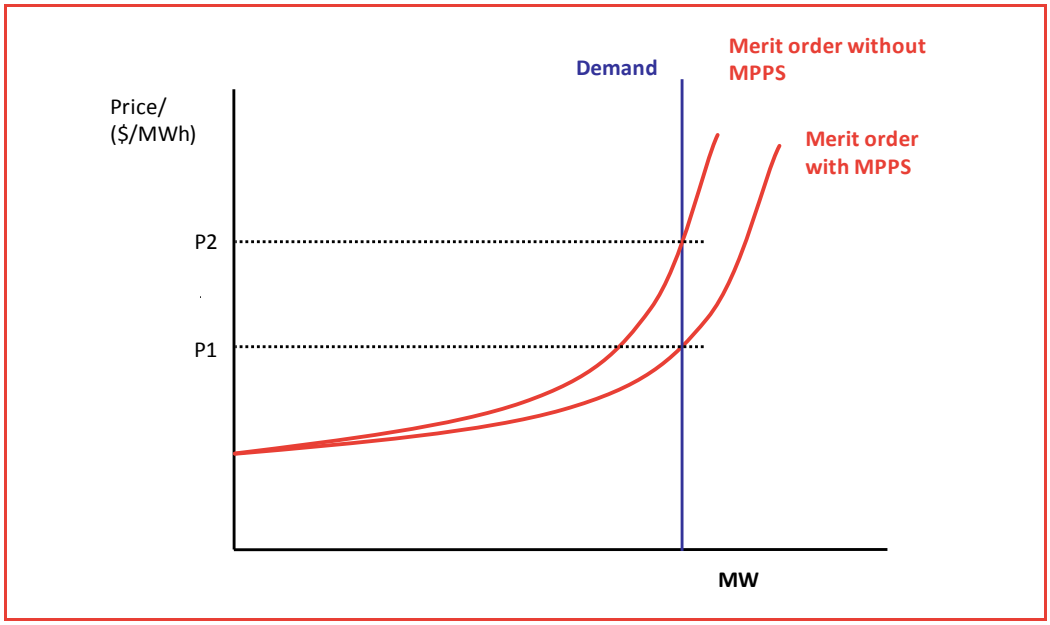
A stylised example is provided in Figure 10, where the supply curve (merit order) shifts left due to the withdrawal of MPPS capacity. Clearly the withdrawal of MPPS has an effect on prices ***because*** it is not operating. If MPPS continued to operate with Coalpac coal it would continue to be a low cost source of supply in the market. The exit of MPPS (due to higher coal costs) will shift the merit order curve inwards by 1184 MW which, all else equal, will result in higher pool prices. In fact, the increase in prices may be relatively large as, since MPPS is a relatively cheap baseload generator, the exit of MPPS may result in more expensive gas fired generators moving left along the merit order resulting in an increase in their dispatch in order to satisfy demand.

Furthermore, all else equal, the increase in pool prices corresponding to the exit of MPPS will also be relatively larger due to the prior exit of WPS. As demonstrated in Figure 9, the removal of one generator also means that any subsequent capacity withdrawal will lead to higher price increases than if the first generator were not withdrawn – the effects are interrelated.

The PAC argument only appears possible if it is assumed that prices will always revert to the same price (LRMC) in the long-run, with or without MPPS (ie that supply is perfectly elastic in the long run). Even if this is the case, the current supply/demand balance means that prices are currently below LRMC, and it will take some time before they revert to this level (perhaps a decade). The difference in prices in the interim will result in significant transfers from electricity consumers to electricity producers (coal generators other than MPPS). This means that any incremental cost from the withdrawal of MPPS would likely result in higher electricity prices for perhaps a decade, which reflects considerable cost even if it results in similar prices in the very long-run. It is also possible that LRMC in the long run will be higher as a result of withdrawing a material source

of cheap coal (and electricity generation) from the market supply curve, though Frontier has not analysed the specific coal supply options and costs.

Figure 10: Stylised example of supply (merit order) with and without Mt Piper



Source: Frontier Economics

4.4 Consideration of other factors

PAC finding

The PAC suggests that the modelling should have accounted for changes in the behaviour of other generators, regulators or the markets. For example:

PAC Report p142:

> There are a number of concerns with the model: [continued]
>
> the model assumes no significant changes other than the price of coal to MPPS over the period. No change is allowed for:
>
> o in the behaviour of other generators;
>
> o in the behaviour of regulators; nor
>
> o in the behaviour of markets.
>
> none of these scenarios are plausible. Major changes in the electricity industry have been foreshadowed recently including substantial reductions in retail power bills398 and changes to regulatory arrangements between the Commonwealth and States. In the Commission's assessment any issues arising from coal supply to MPPS will almost certainly be dwarfed by these impending changes; and

The source cited for this is: *Coorey, P 2012, 'Power bills to fall $250 with electricity reforms', Sydney Morning Herald, 18 October, pp.1-2.*

Frontier Economics comments

The benefits of any regulatory reform that delivers network cost savings and the benefits from the approval of the Coalpac project are not mutually exclusive.

The PAC does not explain what changes in behaviour from generators, regulators or markets it expects will occur. The main example provided relates to regulatory changes that may slow the growth in network costs. The original source for this claim is a Draft Productivity Commission report on Electricity Network Regulatory Frameworks (2012).[6] The report suggested that if Critical Peak Pricing[7] were implemented efficiently it could produce savings of $100-250 per household per year.[8] The PAC appears to suggest that if prices would otherwise fall (due to falling demand or to reform of network regulations) then this would diminish or cancel out any benefits from approving the Coalpac development. This approach is not appropriate in our view. The correct approach would be to consider the counterfactual scenario ***all else being equal.*** The fact that electricity prices may otherwise fall should not be used to discount/offset benefits of the project. Any potential gains from changes to network regulations would be equally attainable irrespective of the approval of the Coalpac project.

4.5 Timeframe

PAC finding

The PAC Report suggests that Delta West's one year stockpile is not a short-term crisis:

> **8.6.4 Short-term Supply of Coal to MPPS**
>
> The Commission sought advice from Energy Australia as to what provision it had made to obtain sufficient coal to operate MPPS in the event that a decision on the project application was delayed beyond the expected date of completion of mining by Coalpac under its current approvals.

6 http://www.pc.gov.au/projects/inquiry/electricity/draft

7

8 Critical Peak Pricing involves very high tariffs during peak demand/price periods, as these are more cost reflective and should discourage demand during those periods, which avoids/defers costly network expenditure. This reform has yet to be implemented, and there has been some controversy even regarding the introduction of time-of-use tariffs due to impacts on some consumer groups (which is a milder form of differential pricing than CPP).

Energy Australia advised that it would have 2 million tonnes stockpiled by the time that Coalpac supplies ceased. This is equivalent to one year's supply by Coalpac under the current arrangements.

There is no short-term crisis.

Frontier Economics comments

Electricity markets are characterised by large, capital intensive investments with long lead times for new investment (2-7 years). This means that supply is "inelastic" in the short to medium term: supply is generally not able to respond quickly to prices. This is exacerbated by another distinctive characteristic of electricity which distinguishes it from other commodity markets: it is very costly to store electricity. This results in highly volatile prices in the spot market. The market deals with this through forward contracting to reduce exposure to these volatile prices. Retailers and generators typically enter "swap" contracts with an agreed price. It is common to contract for 70-80% of capacity, often for up to 2 years in advance.

We understand that alternative coal supply options would require new infrastructure investment to enable physical supply. Not only will this require long-lead times for infrastructure development, it would likely limit EA's supply options and weaken EA's negotiating position. If there is only one-year of stockpile available from Coalpac then this could be considered a short-term crisis.

4.6 Real world example of changes in capacity on price

Frontier Economics has not conducted new modelling of the impact of higher coal prices to MPPS, or reviewed the existing modelling in detail. However, the magnitude of price increases reported in that modelling appears plausible when considered against recent real world examples of similar instances. The following example details the magnitude of wholesale pool price increases in the NEM associated with the withdrawal of a coal fired generator.

4.6.1 Yallourn (Vic)

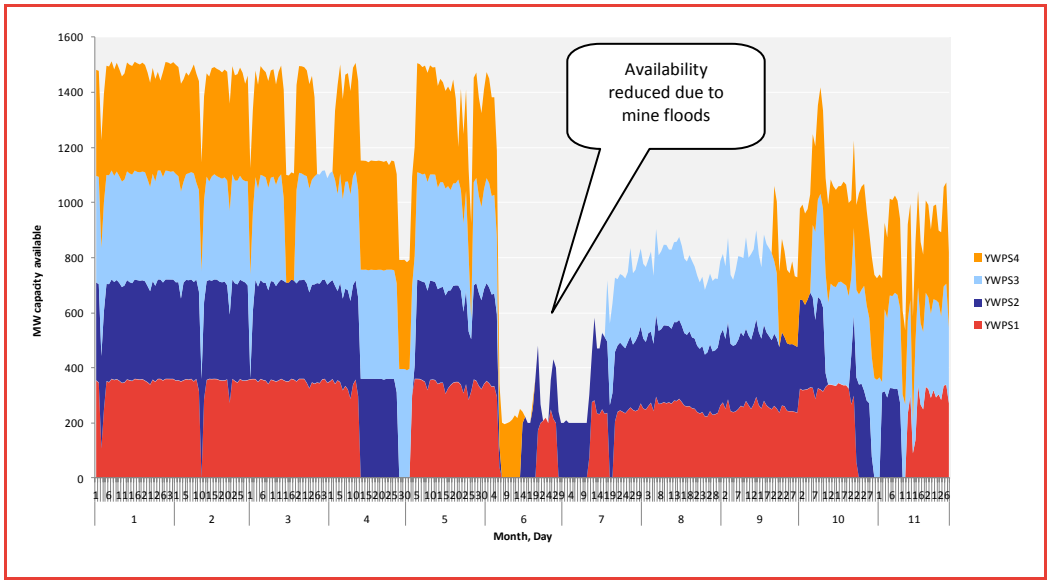
Yallourn is a 1450MW brown coal generator in Victoria's Latrobe Valley. In June 2012, the availability of the plant was reduced due to mine flooding. The impact of this on pool prices across Victoria (and the NEM) was analysed and discussed

in an AEMO review of the impact of the carbon price on spot prices[9]. AEMO concluded that:

> The flooding at Yallourn open-cut mine at the start of June noticeably affected spot prices, generation mix, and interconnector flows. p4; and
>
> The effects of flooding at the Yallourn open-cut mine are also visible in Figure 2-1. The flooding occurred on 6 June 2012 and led to the shutdown of much of Yallourn Power Station. The flooding caused a price increase of around $10/MWh. p6

To explain the AEMO analysis, Figure 11 presents the Yallourn availability of capacity throughout Cal2012, highlighting the reduction that occurred in June.

Figure 11: Yallourn – available capacity in Cal2012

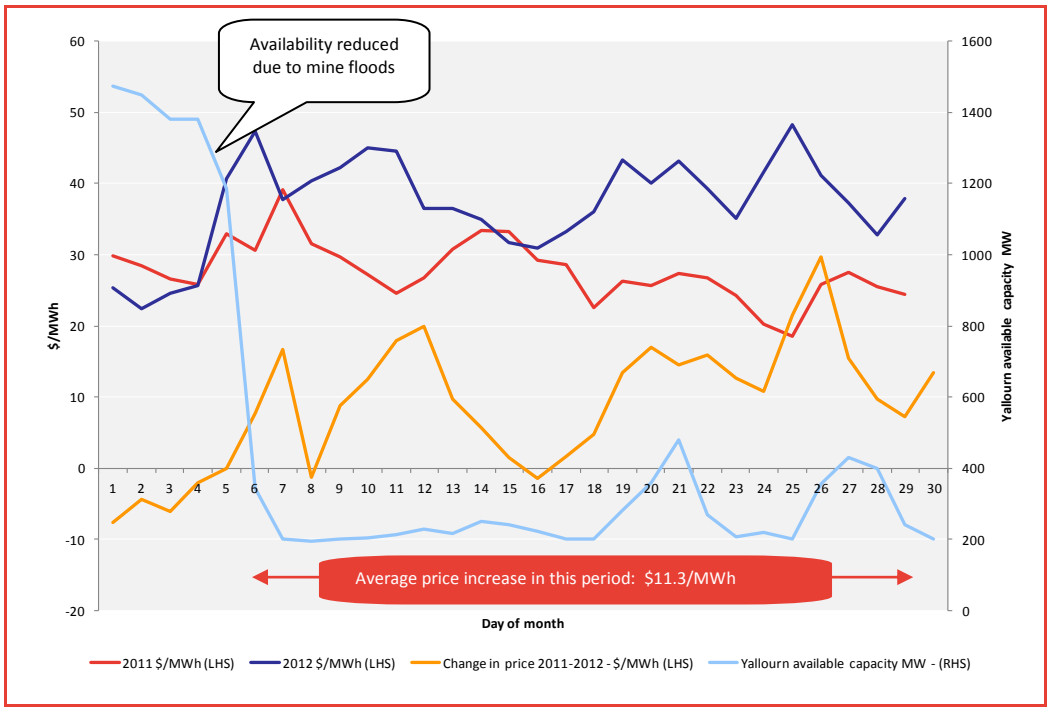


Source: AEMO

Figure 12 presents the comparison of Victorian wholesale pool prices in June from 2011 (red) against 2012 (blue). This is charted against the Yallourn availability in June (light blue) and the difference in prices between years (orange). Prior to June 6, prices were lower in 2012 than in 2011. After June 6, prices were on average $11/MWh higher in 2012. This was an average increase of around 46% for Victorian prices from June 6-June 30. Even though Yallourn is in Victoria, a similar increase was evident in NSW and Qld prices due to the interconnection between regions. Post-June prices are not compared here, as 2012 prices are materially higher due to the introduction of carbon (which cannot be attributed to reduced capacity at Yallourn).

9 AEMO, *Carbon Market Price Review*, Nov 2012. http://www.aemo.com.au/Reports-and-Documents/Reports/~/media/Files/Other/reports/CarbonPrice_MarketReview.ashx

Figure 12: Yallourn capacity impact on Vic pool prices in June 2012



Source: AEMO

This conclusion should be treated with caution given that:

- it involves a very small sample across only 1 month; and
- it is difficult to differentiate causes of price changes when other variables (such as weather, demand, fuel prices and generation capacity/availability) also change from one year to the next.

Nevertheless, the example is based on actual, observed market impacts (as opposed to market modelling) as analysed by AEMO. It demonstrates that a wholesale price increase of around 45% is plausible across the entire NEM, even though the capacity 'withdrawn' from the market only supplies around 8 per cent of the NEM energy.

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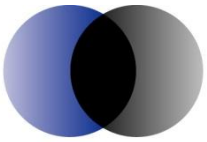
Confidential

Independent Expert Report

Projected market impact of alternate coal supply to Mt Piper and Wallerawang power stations

Prepared for Corrs Chambers Westgarth

28 February 2013



ACIL Tasman

Economics Policy Strategy

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1 Introduction and background

EnergyAustralia currently hold the trading rights for the Mt Piper and Wallerawang power stations in NSW (collectively referred to in this report as the Delta West power stations) under a 'GenTrader' agreement with Delta Electricity which commenced in 2011.

Under this GenTrader arrangement, EnergyAustralia has the right to on-sell power generated from the power stations for the term of the agreement. It is also responsible for the procurement of coal supply for the stations operation.

Whilst the exact details of its existing coal supply portfolio for these stations are commercially sensitive, ACIL Tasman has been advised that a large proportion of future coal requirements are to be sourced from the Cullen Valley Mine/Invincible Colliery development currently proposed by Coalpac in their Consolidation Project. We understand that Delta Electricity has entered into a binding coal supply agreement with Coalpac for the supply of up to 2.5 Mtpa from 2010 and ramps up to full volume by 2014 and ends in 2029. Energy Australia is a beneficiary of this through the GenTrader arrangements.

Coalpac is currently in the process of having its planning application assessed by the NSW Government. EnergyAustralia have advised that if this is not granted it would jeopardise the ability of Coalpac to deliver coal under the supply agreement.

If this situation was to occur, EnergyAustralia would be forced to seek alternative coal supplies to continue operating the Mt Piper and Wallerawang power stations.

ACIL Tasman has been engaged by Corrs Chambers Westgarth on behalf of Energy Australia to undertake a market impact analysis of alternate coal supply arrangements for the Mt Piper and Wallerawang power stations.

Purpose of this report

I have been engaged as an independent expert to provide evidence in relation to these matters. In particular, my instructions are to provide expert opinion on the likely wholesale market impact for New South Wales of a range of alternate coal supply to the Coalpac contract.

This report represents my independent expert views and provides results of detailed electricity market modelling in relation to the above matter.

1.1 About the author

I am a Senior Consultant with ACIL Tasman specialising in electricity, gas and renewable energy markets. I have worked extensively on energy industry matters and across a broad range of assignments including market demand, supply and price forecasting studies; strategic reviews; transmission and distribution networks (project evaluation, throughput forecasts, asset sales and due diligence work); project evaluation (financial modelling, market studies and economic benefits) and regulatory matters. Over the last 12 years with ACIL Tasman, I have personally managed more than 100 energy industry assignments.

In electricity, I have over 12 years' experience undertaking various modelling projects in Australian wholesale electricity markets (NEM and WEM), including short and long-term outlooks and detailed due diligence for asset sales/acquisitions and transmission studies. I have acted as market adviser for a number of clients as part of their due diligence activities in recent years.

I have undertaken a number of assignments in relation to renewable energy and environmental certificate markets, such as the Queensland GEC scheme, NSW GGAS, LRET and SRES. I am the author of ACIL Tasman's 260 page multi-client report "LRET Review and Outlook 2012" which provides a comprehensive review of historical outcomes and projection results for Australia's Large-scale Renewable Energy Target.

I have undertaken a number of forecasting studies for renewable certificate demand/supply and price outlooks in the context of wind farm asset due diligence.

I have also been principally responsible for the design, development and maintenance of a number of ACIL Tasman energy market models, in particular:

- *PowerMark* and *PowerMark LT* – detailed simulation and long-term planning models of the National Electricity Market
- *GasMark* – ACIL Tasman's regional model of the interconnected Australian gas market
- *RECMark* – detailed supply and demand model of the expanded RET scheme.

I hold a Bachelor of Business (Economics and Finance) from Queensland University of Technology and a Graduate Diploma of Applied Finance and Investment from the Financial Services Institute of Australasia (FINSIA).

2 Scope of work

The Scope of Work for this assignment consisted of examination of several scenarios in which coal prices to the Delta West power stations was varied with a view to estimating the likely impact upon wholesale market outcomes.

The scenarios to be examined are as follows:

- **Base case**: ACIL Tasman's current internal Base case projection
- **Scenario A**: The use of a higher coal price series for Delta West power stations, reflecting a view of the export netback price for alternate local coal supplies
- **Scenario B**: The use of the coal prices from Scenario A combined with a coal volume constraint expressed in GWh terms for the two power stations in aggregate.

The alternate scenarios are to be compared with ACIL Tasman's current internal Base Case projection as a point of reference. This standard approach changes only one item at a time to isolate the impact on the market of changing one assumption, in this case coal supply to the Delta West power stations.

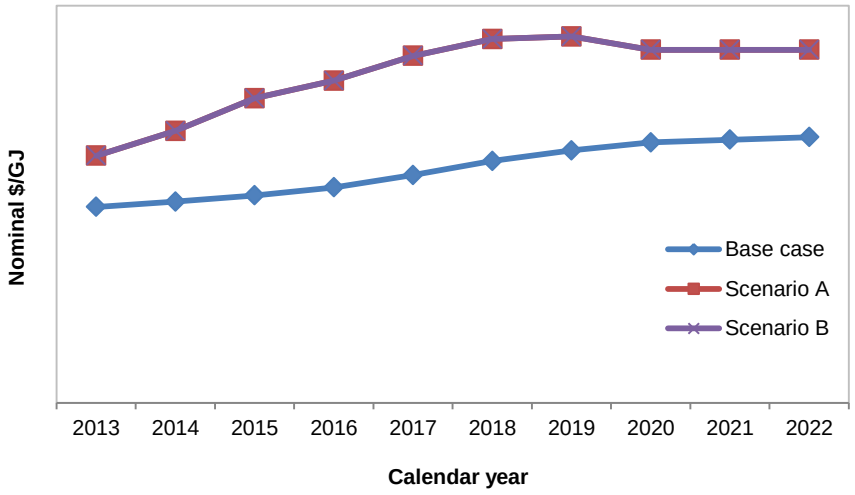
2.1 Documents and information provided

The only information provided to undertake this assignment were the coal prices for the alternate scenarios and coal constraint volumes for Scenario B. All other modelling assumptions used (including the coal prices in the Base case) were taken from ACIL Tasman's standard Base Case assumptions set.

The coal prices for the Base Case and alternative scenarios are shown in Figure 1. In addition, Scenario B involves the use of a constraint on coal volumes available to the Delta West stations in aggregate. This constraint has been provided in terms of dispatch volumes rather than coal tonnages as shown in Figure 2.

I am informed that the alternate coal price used in this analysis was produced by an independent expert commissioned by the client. Coal volume assumptions are understood to be representative of coal able to be supplied locally in the absence of the Coalpac contract. I have not been asked to analyse or provide a view on the alternate coal price series or coal constraint levels provided.

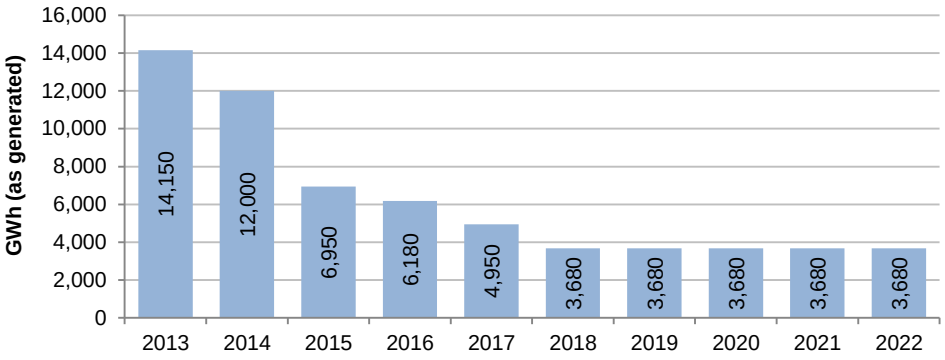
Figure 1 **Coal prices used in the market projections**



Note: Coal prices are in nominal dollars delivered to the power stations. Values redacted due to commercial sensitivity

Data source: Base case: ACIL Tasman, Scenario A & B: Corrs Chambers Westgarth

Figure 2 **Delta West dispatch constraint for Scenario B**



Note: Coal volumes expressed in GWh dispatch terms

Data source: Corrs Chambers Westgarth

3 Projection results

This section provides a succinct summary of the high level results of the market modelling exercise. The market modelling was undertaken using ACIL Tasman's in-house electricity market model *PowerMark*.

The projections cover the 10 year period from 2013 to 2022. Results are provided for the Base Case scenario which reflects ACIL Tasman's Base case outlook for the market and our understanding of the current coal supply situation for the Delta West power stations. This is used as a reference case for the evaluation of the alternate scenarios.

The National Electricity Market (NEM) is a competitive market in which generators compete economically for dispatch and revenue. As a market-based system, the marginal cost of a particular power station is a key determinant in its financial and operational performance. For most fossil fuelled power stations the largest component of variable costs is fuel, with this typically being valued at its replacement/opportunity cost.

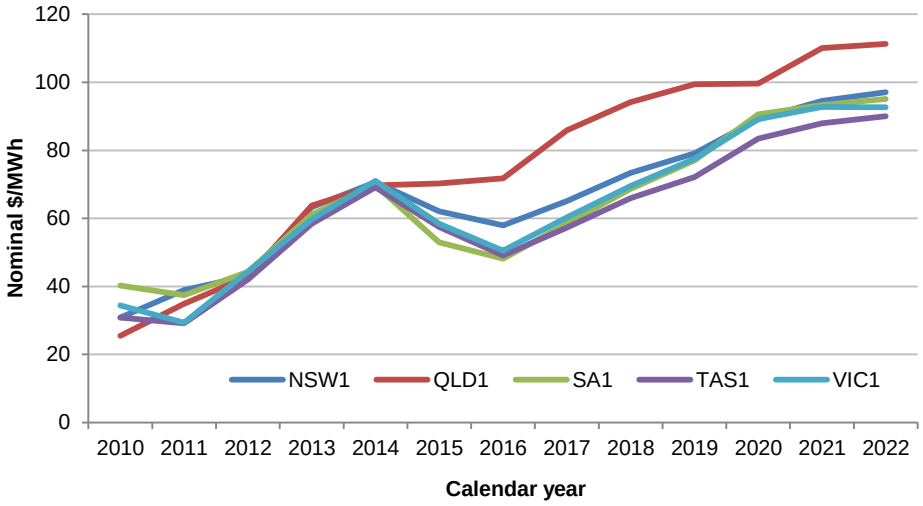
Mt Piper has a higher thermal efficiency than Wallerawang; its marginal cost of operation is therefore lower (for any given coal price) and therefore will generally be dispatched in preference to Wallerawang. As the two stations are located close to one another and effectively share coal supply, coal volumes can be redirected to Mt Piper at the expense of Wallerawang.

Given the potential for higher coal prices under the scenarios examined in this report, a reduction in output from Wallerawang will naturally occur before Mt Piper. Unused coal volumes originally destined for Wallerawang could then be utilised at Mt Piper. This reflects an economically rational decision by the station's operator.

3.1 Base case

Figure 3 shows actual and projected time-weighted average Regional Reference Prices (RRP) for each NEM region under the Base case. These projections represent ACIL Tasman's current internal view on the market's outlook. Input assumptions for this scenario are compiled from a range of public and private sources including internal estimates where necessary. ACIL Tasman's Base case is updated regularly to incorporate new market developments and revised assumptions. This Base case is current as at February 2013.

Figure 3 **Projected time-weighted average RRP: Base case**



Note: Years 2010 to 2012 are actuals. Time-weighted RRP presented at the Regional Reference Node
Data source: AEMO, ACIL Tasman PowerMark modelling

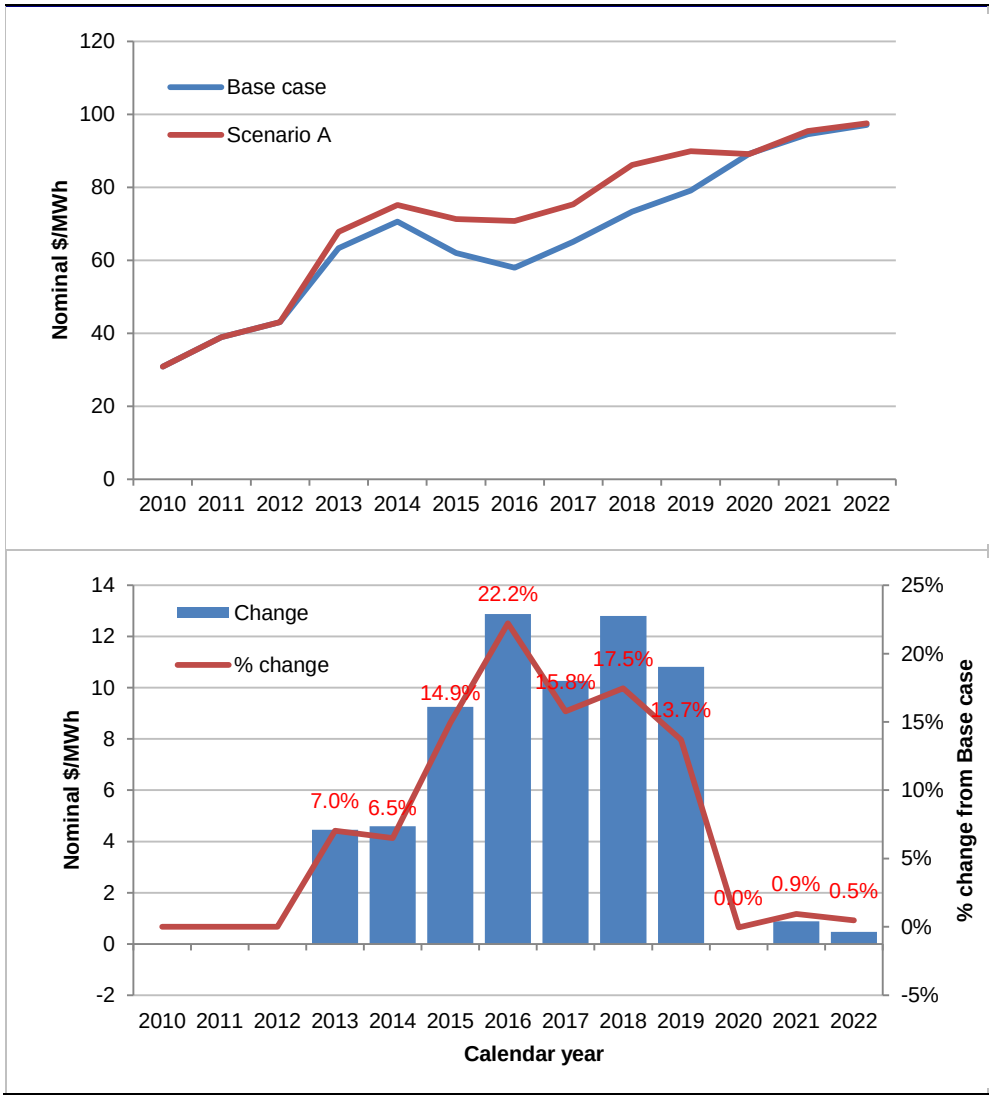
The price trajectory shows a continuing trend of rising prices through 2013 and 2014 driven by increasing fuel costs and explicit carbon pricing through the Federal Government's Clean Energy Future package. Prices are anticipated to decline in 2015 and 2016, largely a result of the anticipated fall in the carbon price from 1 July 2015 as our scheme is linked to the European Emissions Trading Scheme. Prices trend upward after 2016, reflecting ongoing increases to fuel and carbon costs.

3.2 Scenario A: Alternate local coal supply

Scenario A includes the higher coal prices to the Delta West power stations as detailed in Figure 1. All other assumptions in the projection remain unchanged.

Figure 4 shows the projected RRP under this scenario in comparison with the Base case. Projected NSW prices are higher through the period 2013 to 2019 before converging back to the Base case level thereafter. The NSW wholesale price is projected to be up to 22% higher in 2016 relative to the Base case.

Figure 4 **Projected NSW RRP: Scenario A**



Note: Time-weighted RRP presented at the Regional Reference Node
Data source: ACIL Tasman PowerMark modelling

The increased coal price to the Delta West stations results in Wallerawang (the older and less efficient of the two power stations) taking on a reduced operational role and only operating through high priced months of the year. This results in an acceleration of the development of new entrant capacity in NSW which limits the potential price increases.

By 2020, the rising NSW wholesale price results in Wallerawang being able to resume an all-year-round running regime. As prices have converged on new entry levels by this time there is minimal change from the Base case.

3.3 Scenario B: Coal constraint

Scenario B assumes the same coal price as Scenario A, but also introduces a constraint upon the annual output of the Delta West stations in aggregate as shown in Figure 2. This volume constraint is designed to reflect a situation where replacement coal volumes are unable to be sourced locally due to local production being export bound. Alternate coal supplies available from northern coal fields also prove to be uneconomic in light of the necessary infrastructure investments and higher transport costs.

Figure 5 shows the corresponding impact upon NSW wholesale prices under this scenario. NSW prices are significantly higher – up to 28% higher in 2017 and remain well above the Base case levels throughout.

Due to the limitation on coal availability, output from Wallerawang is severely constrained. The station operates a limited seasonal running regime initially and is forced into early retirement from 2016 onwards.

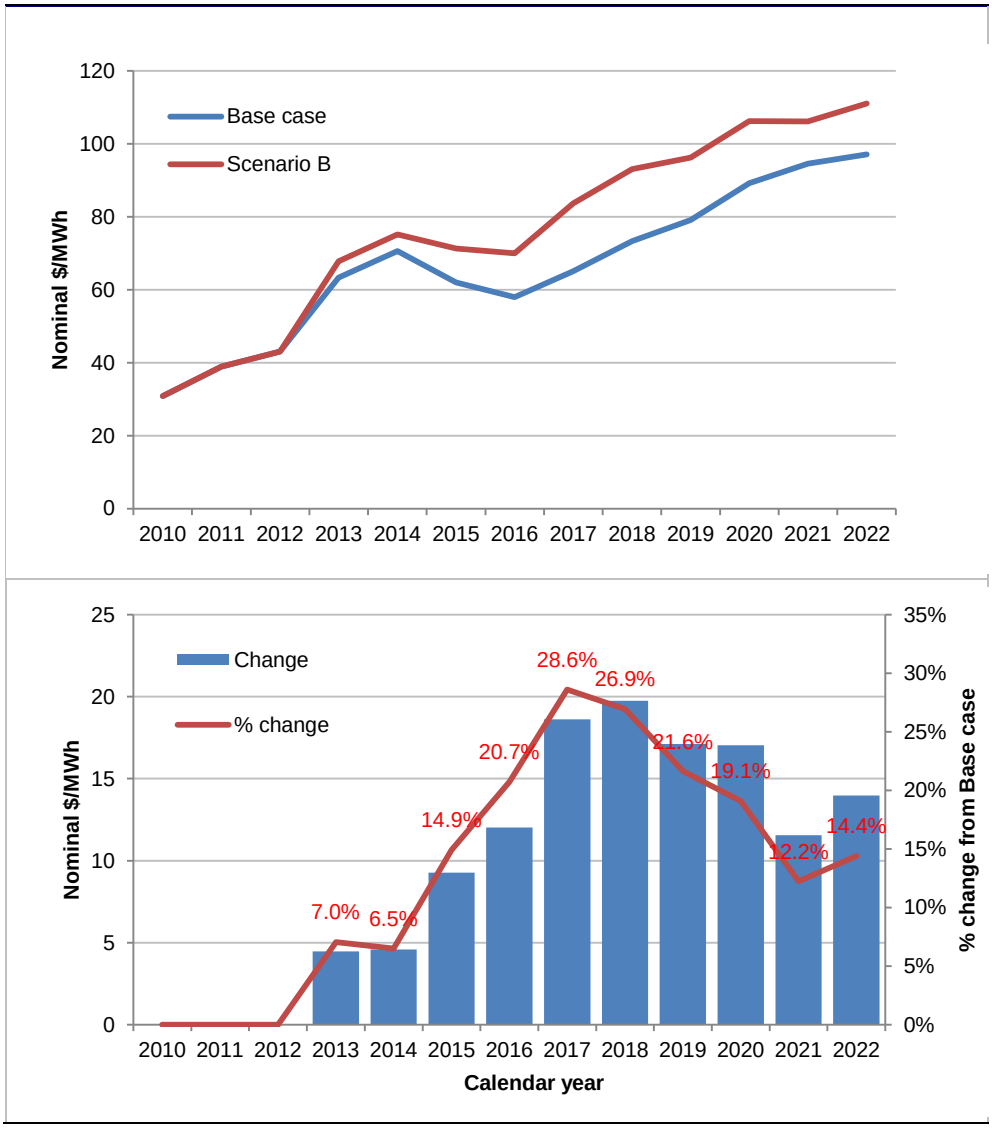
The coal constraint also forces Mt Piper power station to operate a single unit only from 2017 onwards. The single operational unit is also only available to run between 9 and 10 months of the year.

The removal of the majority of the Delta West stations from service prompts the development of new entrant capacity. The modelling suggests the need for around 2,000 MW of open cycle gas turbines and a 400 MW combined cycle gas turbine by 2022 in NSW. This compares with only 600 MW of open cycle gas turbine capacity by this time under the Base case, a net increase of 1,800MW. This implies additional generation investment of $1.6 billion in NSW by 2022.[1]

While the modelling approach assumes perfect foresight and new generation is built in a timely fashion, in practice the market tends to require a clear price signal before making commitments to new capacity. If the Delta West capacity is withdrawn from the market without new entrant capacity being developed in a timely fashion, the market impacts could be greater than shown here.

[1] Based on conservative estimated capital costs of $800/kW for open cycle gas turbine and $1,200/kW for combined cycle gas turbine plant

Figure 5 **Projected NSW RRP: Scenario B**

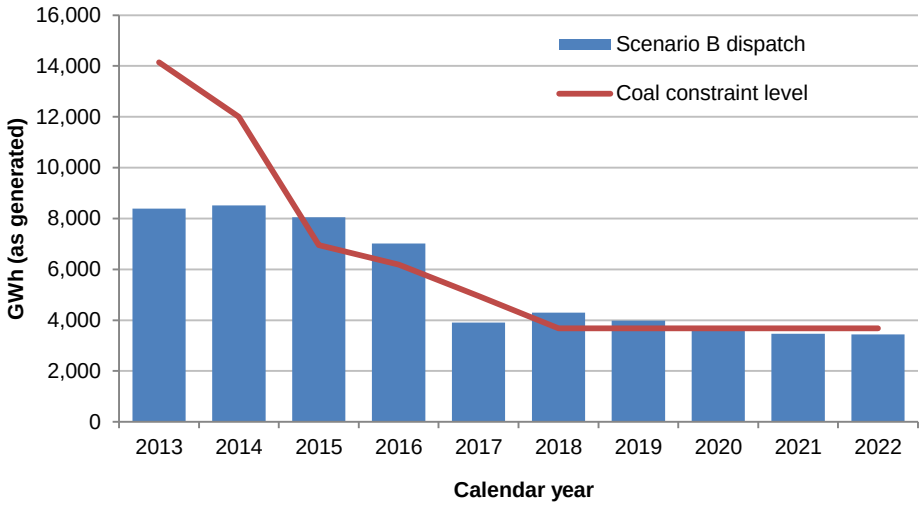


Note: Time-weighted RRP presented at the Regional Reference Node

Data source: ACIL Tasman PowerMark modelling

Figure 6 shows the aggregate dispatch levels for Delta West plant relative to the coal constraint level applied within the modelling. The coal constraint does not bind in 2013 and 2014.

Figure 6 **Delta West dispatch against constraint level**



Data source: ACIL Tasman PowerMark modelling

4 Impact on consumer surplus

The higher wholesale electricity prices under Scenarios A and B have a negative effect upon consumers in NSW. Table 1 shows the calculated loss of consumer surplus relative to the Base case under Scenario A and B. This calculation utilises the load-weighted price outcomes under each scenario and multiplies this by the estimated volume of electricity consumed after power station auxiliary usage and transmission losses are deducted (defined within the table as 'Implied customer sales").[2]

The aggregate loss of consumer surplus over the period 2013 to 2022 is significant at around $5.5 billion in nominal terms ($3.8 billion in present value terms) under Scenario A. Under Scenario B it is larger at $10.5 billion in nominal terms ($6.1 billion in present value terms).

Table 1 **Change in NSW consumer surplus relative to Base case**

	NSW demand (GWh)		Change in load-weighted price from Base case (Nominal $/MWh)		Change in consumer surplus (Nominal $m)			Change in consumer surplus (Present value $m)	
Calendar year	As Generated	Implied customer sales	Scenario A	Scenario B	Scenario A	Scenario B	PV deflator	Scenario A	Scenario B
2013	72,989	67,357	$5.74	$5.74	-$387	-$387	1.000	-$387	-$387
2014	74,086	68,386	$5.67	$5.67	-$388	-$388	0.893	-$346	-$346
2015	75,289	69,515	$11.51	$11.51	-$800	-$800	0.797	-$638	-$638
2016	76,306	70,467	$16.86	$15.10	-$1,188	-$1,064	0.712	-$846	-$758
2017	77,434	71,525	$11.18	$20.97	-$799	-$1,500	0.636	-$508	-$953
2018	78,351	72,389	$15.36	$22.93	-$1,112	-$1,660	0.567	-$631	-$942
2019	78,995	72,996	$11.79	$18.98	-$861	-$1,386	0.507	-$436	-$702
2020	79,858	73,805	-$0.75	$19.28	$55	-$1,423	0.452	$25	-$644
2021	80,771	74,658	$0.69	$10.71	-$52	-$800	0.404	-$21	-$323
2022	81,601	75,432	-$0.02	$15.34	$1	-$1,157	0.361	$0	-$417
Total					-5,529	-10,564		-3,786	-6,109

Note: Present value (PV) calculation uses a 12% nominal discount rate

Data source: ACIL Tasman PowerMark modelling

[2] The ratio between 'As generated' energy and "Implied customer sales" is taken from ratios within the AEMO 2012 National Electricity Demand Forecasting report for NSW.