Debt raising transaction costs

United Energy

April, 2015

INCENTA
ECONOMIC CONSULTING

Table of Contents

1. Executive Summary

Background

United Energy has engaged Incenta Economic Consulting (Incenta) to estimate the prudent and efficient total debt raising transaction costs that a benchmark electricity distribution network with United Energy's characteristics would be expected to incur. It has also requested us to undertake a review of the issues raised by the Australian Energy Regulator (AER) in its draft decisions for Transgrid, Jemena Gas Networks (JGN) and ActewAGL, where it rejected the forecast total debt raising costs proposed by these businesses (the network proposals), and to respond to them.[1]

Allowance for debt raising transaction costs relating to the debt component of the RAB

In relation to the network proposals the AER broadly accepted the methodology that we had applied to estimate transaction costs relating to the debt raising component of the total debt raising transaction costs, as it is essentially the same methodology that it applies (i.e. based on the 2004 report by ACG). However, the AER's arrangement fee component was always slightly lower than the 8.5 bppa that was estimated by the most recent PwC (2013) study examining these fees.[2] We expect that this is due to the AER having applied its lower estimated WACC rather than the generic 10 per cent rate that was applied by PwC to levelise the arrangement fees that it observed empirically. In principle, we agree with the AER that this is an appropriate adjustment, and we have adjusted our methodology accordingly, but have used United Energy's WACC estimates to inform our estimate.

Allowance for costs associated with Standard & Poor's liquidity requirement

The AER has rejected accepting liquidity costs because it considers 'the PTRM's timing assumptions already provide adequate compensation for the timing of revenue compared to expenses.'[3] However, the National Electricity Rules (NER, 6.5.6(a)) state that a regulated electricity distribution business is obliged to 'include the total forecast operating expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to achieve each the following [operating expenditure objectives]'. Similarly, the NER (6.5.6 (c)) require that the Distribution Network Service Provider must assess 'the costs that a prudent operator would require to achieve the operating expenditure objectives'. The Rules do not provide the AER with a choice about whether it should consider liquidity costs are already compensated through the formula that is used in the PTRM model. Instead they require the AER to accept the DNSP's forecast of required operating expenditure if these are efficient costs that a prudent operator would incur.

As evidence that liquidity costs are not prudent, the AER points to the fact that a number of service providers (Ausgrid, Endeavour, Essential and Transend) were aware of the additional cost categories contained in the network proposals, but had chosen not to include them in their opex proposals. However, these are government owned businesses subject to a competitive neutrality regime that provides only an approximation of the cost differential between a government owned entity and a

---

1 AER (November, 2014a), *Draft decision – TransGrid transmission determination 2015-16 to 2017-18, Attachment 3: Rate of* return; AER (November, 2014b), *Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2015-20, Attachment 3: Rate of return*; AER (November, 2014c), *Draft decision – ActewAGL distribution determination, Attachment 3: Rate of return.*

2 See, PwC (June, 2013), p.19; and Australian Energy Regulator (November, 2014), p.3-326.

3 Australian Energy Regulator (November, 2014), p.3-322.

stand-alone privately owned business that reflects the characteristics of the benchmark entity. The AER's objections are contradicted by the evidence relating to privately owned businesses that was provided in our previous reports,[4] and to which the AER provided no response:

- An executive of Standard & Poor's told us that most privately owned regulated energy transmission and distribution businesses are likely to incur liquidity maintenance costs – the AER has not indicated whether it has conferred with Standard & Poor's on this point; and

- Research by PricewaterhouseCoopers (PwC) and CEG has shown that undrawn bank debt accounts for between 8 per cent and 14 per cent of total drawn debt – the AER has not provided any evidence that it has investigated these claims. [5]

We therefore conclude that the AER has provided no valid reason to reject liquidity costs as being imprudent or inefficient. The only evidence that was provided (the fact that government owned businesses have not requested it) is muted.

Allowance for costs associated with Standard & Poor's requirement to finance 3 months ahead

As noted above for liquidity costs, the NER require the AER to decide whether three month ahead financing costs are 'costs that a prudent operator would require to achieve the operating expenditure objectives.' The AER has provided no evidence that it has empirically investigated this matter, and has not indicated that it has conferred with Standard & Poor's on this matter.

The AER also expressed a concern that our original estimate of the cost of 3 month ahead financing would tend to over-estimate the actual cost, because we estimated the cost based on the difference between the return on the cost of BBB+ debt over the past 10 years (i.e. the trailing average), and the offsetting return that would be earned on a 3 month BBB+ corporate bond. This was expected to over-estimate the cost of 3 month ahead financing, because the trailing average cost of BBB+ rated debt is currently higher than the current cost of BBB+ rated debt (which is relevant to a refinancing). We agree with the AER that it is not consistent to apply a trailing average cost of debt to estimate the cost of 3 month ahead financing, since it is the rate of return on the new debt that is issued that is the cost that is partly offset by investment in short term bonds. We have amended our methodology accordingly.

Again we note that Standard & Poor's requires investment grade issuers to re-finance bonds 3 months ahead of expiry. There is a cost to this, and in this report we have estimated that cost using the approach suggested by the AER.

---

4 Incenta (May, 2014a) *Debt Raising Transaction Costs - ActewAGL Distribution*; Incenta (May, 2014b) *Debt Raising Transaction Costs - TransGrid*; Incenta (June, 2014) *Debt Raising Transaction Costs – Jemena Gas Networks*.

5 ENA (11 October, 2013*), Response to the Draft Rate of Return Guideline of the Australian Energy Regulator*, p.76. The businesses covered by the CEG estimate of undrawn debt facilities were the Cheung Kong Group (SA Power Networks, United Energy and Powercor), Envestra, ElectraNet, SP AusNet, DUET Group (MultiNet Gas and United Energy) and APA Group.

Other objections raised by the AER

A further objection of the AER to including an allowance for liquidity and 3 month ahead financing costs is the relative complexity of doing so.[6] We do not agree with the AER's assessment. We observe that both of these costs can be estimated purely with reference to benchmark parameters, that very few additional inputs are required, and that these additional inputs are relatively straightforward to establish.[7]

The AER also stated that in a previous 2012 draft decision on Envestra, it had set out its reasons for the decision not to include liquidity costs, and that 'neither [the network proposals] nor Incenta has engaged with the reasons set out in this decision'.[8] We did address some of these reasons implicitly in our earlier reports, and have addressed all explicitly in this report. In our view, none of the AER's objections remain valid. The AER's main argument was that the PTRM calculation contained offsetting biases elsewhere, which we have addressed already above. The AER's two further arguments were that:[9]

- *The assumed dividend payout ratio (which is an input into the liquidity cost) was too high* – our earlier reports (and this report) applied the payout ratio implicit in the AER's 'gamma' assumption, and so applied the assumption the AER indicated that it would prefer in that earlier draft decision, and

- *Firms would reduce capital expenditure or withhold distributions if faced with a crisis* – we have confirmed with Standard & Poor's staff that when Standard & Poor's calculates the liquidity levels it expects in order for firms to maintain an investment grade credit rating that its modelling of cash flows assumes that the forecast capital expenditure and distributions continue in the event of a market collapse, which means that the AER's assumption that firms would be expected to change their capital expenditure or distributions was incorrect.[10]

Finally, the AER proposed that if the working capital allowance implicit in the PTRM formula was to be included in the calculation of liquidity ratios, 'then using Envestra's calculation method, an allowance for liquidity would not be required.' However, the Standard & Poor's liquidity formula only includes net working capital as a source of liquidity; and furthermore, in the case of United Energy we found that committed undrawn bank lines would on average need to be in the order of

6 AER (November, 2014a), p. 3-328; AER (November, 2014b), p. 3-313; AER (November, 2014c), p. 3-322.

7 The additional inputs required are the return on 3-month BBB+ debt (an input into the early refinancing cost), the 3 year swap rate (an input into the liquidity cost) and the establishment fee and legal fees for bank debt (inputs into the liquidity cost). Only the last two of these inputs cannot be observed directly from market interest rates, and it would be straightforward to update these inputs periodically when the cost of issuing bonds is updated (and, in any event, the establishment fee and legal fees only make a small contribution to the liquidity cost).

8 AER (November, 2014a), p. 3-329; AER (November, 2014b), p. 3-315; AER (November, 2014c), p. 3-324.

9 AER (September, 2012), p.201.

10 Firms may actually reduce capital expenditure or distributions in the event of a market collapse; however, the relevant issue for calculating the liquidity cost is what Standard and Poor's assumes in the modelling that Standard and Poor's undertakes to establish required liquidity levels.

$130 million. This is more than a quarter of the annual regulated revenue requirement, which is clearly much larger than any implicit working capital allowance.

1.1 Total debt-raising transaction costs

In summary, we consider that the NER require United Energy to estimate all the efficient costs that would be incurred by a prudent DNSP. Our analysis, which includes the impact of corrections made by reference to points raised by the AER, estimates the benchmark, direct levelised debt raising costs (expressed in terms of basis points per annum on regulatory debt) as:[11]

- **9.1 basis points per annum** for the costs of issuing the bonds in an assumed debt portfolio of $1,242 million (i.e. RAB debt);

- **7.8 basis points per annum** to establish and maintain bank facilities required to meet Standard & Poor's liquidity requirements condition for maintaining an investment grade credit rating; and

- **3.1 basis points per annum** to compensate for the requirement (again as a condition of maintaining an investment grade credit rating) that Standard & Poor's requires businesses to re-finance their debt 3 months ahead of the re-financing date.

Summing these components we have estimated a total levelised cost of debt raising transaction costs of **20.0 basis points per annum** on the regulatory debt. [12]

[11] That is, using United Energy's average forecast nominal vanilla WACC of 7.38 per cent as the discount rate, we calculated the NPV of these transaction costs over the regulatory period and divided by the NPV of the RAB values over the same period to obtain a levelised cost in basis points per annum.

[12] That is, using an average discount rate of 7.38 per cent, we calculated the NPV of these transaction costs over the regulatory period and divided by the NPV of the RAB values over the same period to obtain a levelised cost in basis points per annum.

2. Terms of Reference and outline of report

2.1 Terms of Reference

United Energy has engaged Incenta Economic Consulting (Incenta) to estimate the prudent and efficient total debt raising transaction costs that a benchmark electricity distribution network with United Energy's characteristics would be expected to incur. It has also requested us to undertake a review of the issues raised by the Australian Energy Regulator (AER) in its draft decisions on Transgrid, Jemena and ActewAGL, where it rejected the forecast total debt raising costs proposed by these businesses (the network proposals), and to respond to them.

2.2 Outline of report

The current report is organised as follows:

- In section 3 we respond to the points raised by the AER in its draft decisions on the network proposals; and

- In section 4 we provide an estimate of the levelised total benchmark debt raising transaction cost that is incurred by a benchmark business with the characteristics of United Energy.

3. Response to the AER's draft decision

3.1 Introduction

In this section we consider the AER's response to our original reports on total debt raising transaction costs, which formed part of the network proposals. Our responses are organised according to the three components of debt raising transaction costs:

- Debt raising transaction costs relating to the debt component of the RAB;
- Allowance for costs associated with Standard & Poor's liquidity requirement; and
- Allowance for costs associated with Standard & Poor's requirement to finance three months ahead.

3.2 Allowance for debt raising transaction costs relating to the debt component of the RAB

Our approach to estimating the allowance for debt raising transaction costs relating to the debt component of the RAB is based on the market research results of the recent PwC study of debt raising transaction costs relating to the RAB debt,[13] and is consistent with the ACG (2004) study that largely informs the AER's approach. For example, the AER updated the RABs contained in the network proposals, and from this estimated projected benchmark debt levels, which were multiplied by the benchmark rates for debt raising transaction cost to estimate the debt raising cost allowances. The AER stated that it:[14]

> *…updated the individual transaction cost line items (including the arrangement fee) for the draft decision's opening RAB and rate of return. We have done these calculations in line with Incenta and PwC's descriptions of the basis on which the costs are allocated per program, per issue or per annum.*

However, in its draft decisions relating to the network proposals, the AER applied arrangement fees in the range of 7.38 bppa to 7.53 bppa rather than the 8.5 bppa that was estimated by the most recent PwC study examining these fees.[15] We expect that this is due to the AER having applied its estimated WACC range of 6.80 per cent to 7.24 per cent for these businesses rather than the generic 10 per cent rate that was applied by PwC. In principle, we agree that this is an appropriate adjustment, and we have adjusted our approach accordingly. However, consistent with United Energy's proposal we have used a nominal vanilla WACC of 7.38 per cent.

---

13 PwC (June, 2013), *Energy Networks Association: Debt financing costs.*

14 AER (November, 2014a), p. 3-327; AER (November, 2014b), p. 3-312; AER (November, 2014c), pp. 3-321 to 3-322.

15 See, PwC (June, 2013), p.19; and AER (November, 2014a), p. 3-327; AER (November, 2014b), p. 3-312; AER (November, 2014c), pp. 3-321 to 3-322.

3.3 Allowance for costs associated with Standard & Poor's liquidity requirement

Validity of including liquidity costs as part of the service provider's forecast operating costs

One reason that the AER has rejected accepting liquidity costs is that it considers that 'the PTRM's timing assumptions already provide adequate compensation for the timing of revenue compared to expenses.' [16] However, under the National Electricity Rules (NER) 6.5.6 (a), a regulated electricity distribution business 'must include the total forecast operating expenditure for the relevant regulatory control period which the *Distribution Network Service Provider* considers is required in order to achieve each of the following (operating expenditure objectives)'. The list of objectives includes maintaining the quality, reliability and security of supply of the *prescribed distribution services*.

Similarly, under the NER (6.5.6 (c)):

> *The AER must accept the forecast of required operating expenditure of a* ***Distribution Network Service Provider*** *that is included in a* ***building block proposal*** *if the AER is satisfied that the total of the forecast operating expenditure for the* ***regulatory control period*** *reasonably reflects each of the following (the* ***operating expenditure criteria****):*
>
> *(1) the efficient costs of achieving the* ***operating expenditure objectives****;*
>
> *(2) the costs that a prudent operator would require to achieve the* ***operating expenditure objectives****; and*
>
> *(3) a realistic expectation of the demand forecast and cost inputs required to achieve the* ***operating expenditure objectives****.*

The Rules do not provide the AER with a choice about whether to deem that liquidity costs are already compensated by the revenue implications of the PTRM model. Instead the Rules are clear in requiring the AER to accept the forecast of required operating expenditure if these are efficient costs, and the costs that a prudent operator would require to achieve the operating expenditure objectives. Since 2001 Australian regulators have accepted that debt raising transaction costs are a valid cost component, and have provided allowances varying between 5 bppa and 25 bppa. The AER has done so since its inception.

Liquidity costs are the costs incurred by a regulated business due to a requirement imposed by credit rating agencies that require a buffer of either cash, or committed but unused bank lines to be held so that debt re-financing can take place even in the event that there is a temporary closure of credit markets. As noted in our previous reports, liquidity costs are direct costs, since they involve an explicit cash outlay by businesses in the form of additional bank fees (which are not included in the bond issuance costs that are recognised as an explicit operating cost), and bank commitment fees. Standard & Poor's considers that almost all regulated energy businesses are likely to require a liquidity reserve, and that this is a direct cost of operations. This fact was not commented upon in the AER's draft decision.

16 AER (November, 2014a), p. 3-327; AER (November, 2014b), p. 3-322; AER (November, 2014c), p. 3-313.

The AER's draft decision maintains that it is 'not satisfied that a prudent operator requires this additional expenditure [to satisfy liquidity requirements].'[17] In support of this proposition the AER pointed to the fact that a number of service providers (Ausgrid, Endeavour, Essential and Transend) were aware of the additional cost categories contained in the network proposals, but had chosen not to include them in their opex proposals, and Directlink had used the AER's normal approach on debt raising transaction costs. We are not privy to the basis used by some businesses to not include these costs in their revenue proposals. However, we note that each of JGN, TransGrid and ActewAGL have included these costs in their revenue proposals (which was not mentioned by the AER).

In its draft decisions on the network proposals the AER's scepticism that regulated businesses actually incur costs due to liquidity requirements is contradicted by the evidence that was provided in our previous reports:

- The statement made to us by an executive of Standard & Poor's, that it is highly likely that regulated energy transmission and distribution businesses will incur liquidity maintenance costs – the AER has not stated that it has conferred with Standard & Poors' to confirm whether this is in fact the case; and

- We have cited research by PricewaterhouseCoopers (PwC) and CEG, where it was respectively shown that undrawn bank debt (which is considered to be the most efficient way of providing a liquidity buffer) accounts for between 8 per cent and 14 per cent of total drawn debt.

Hence, it has been shown empirically that an efficient benchmark entity would have to incur these costs. On the other hand, without undertaking an empirical investigation of the matter, and relying solely on the observation that some businesses have not requested compensation for these costs, the AER has concluded that it is 'not satisfied that a prudent operator requires this additional expenditure'. We conclude that there is no valid reason for the AER not to accept liquidity costs as prudent costs that the benchmark entity would need to incur in order to achieve its operating expenditure objectives.

3.4 Allowance for costs associated with Standard & Poor's requirement to finance 3 months ahead

The AER's concerns about recognising 3 month ahead financing costs

Regarding liquidity costs, in its draft decisions on the network proposals the AER considered that the low materiality of the three month ahead financing costs mean that these costs can be considered to be covered by the favourable revenue impact of timing assumptions in the PTRM. As noted above for liquidity costs, the NER do not provide the AER with such discretion, but require it to decide whether these are 'costs that a prudent operator would require to achieve the operating expenditure objectives.'

The AER has not provided evidence that it has empirically investigated this matter. For example, it has not indicated that it has conferred with Standard & Poor's, whose staff told us that these costs are being incurred by credit rated, regulated energy transmission and distribution businesses (i.e. the businesses that are reflective of the characteristics of the benchmark entity).

[17] AER (November, 2014a), p. 3-328; AER (November, 2014b), p. 3-313; AER (November, 2014c), p. 3-322.

The AER also expressed doubts that the estimate of the cost of 3 month ahead financing contained in our previous reports will tend to provide an over-estimate of the actual cost incurred by the benchmark firm. This is because we estimated the cost based on the difference between the return on the cost of BBB+ debt over the past 10 years (i.e. the trailing average), and the return that would be earned on a 3 month BBB+ corporate bond. However, as noted by the AER, this would tend to over-estimate the cost of 3 month ahead financing, because the trailing average cost of BBB+ rated debt is currently higher than the spot cost of BBB+ rated debt. We agree that our approach over-estimated the cost of 3 month ahead financing.

In conclusion, we reiterate that Standard & Poor's requires investment grade issuers to re-finance bonds 3 months ahead of expiry. There is a cost to this, and we have estimated that cost below, taking account of the criticisms outlined by the AER.

3.5 Other objections raised by the AER

The relative complexity of including liquidity and three month ahead financing costs

The AER's final objection to including liquidity and 3 month ahead financing costs is the relative complexity of doing so:[18]

> *These proposed allowances result in a more complex regulatory approach to estimate debt raising costs given the modelling and data requirements to estimate these two additional categories.*

We do not agree with the AER's assessment. From its inception the AER has assessed debt raising transaction costs associated with bond issues. Since the time of the original ACG (2004) report, there have been several updates of the parameters that are used in this analysis. The latest update was the one undertaken by PwC in 2013. The application of the ACG methodology required PwC to:

- Assess the average size of bond issue made by Australian infrastructure business;
- Search Bloomberg to find examples of Australian companies that had issued bonds in the US, and for the arrangement fees paid for those services to be revealed in a Prospectus.
- Survey a number of banks about the charges that they would apply to facilitate bond issues;
- Survey credit rating agencies about the fees that they charge for bond issues and bond programs; and
- Survey law firms about the charges that they would apply to facilitate bond issues.

There are relatively few additional information requirements necessary to estimate the costs of maintaining liquidity and 3 month ahead financing: the return on 3-month BBB+ debt (an input into the early refinancing cost; the 3 year swap rate (an input into the liquidity cost); and the establishment fee and legal fees that are an input into the liquidity cost. Bank establishment fees (to estimate the cost of the establishing a bank facility) and legal fees are currently available (PwC, 2013). At the next

18 AER (November, 2014a), p. 3-328; AER (November, 2014b), p. 3-313; AER (November, 2014c), p. 3-322.

iteration it would be a very small incremental cost to estimate bank fees and legal fees alongside bond issuance fees, as the same parties would need to be surveyed (i.e. banks and legal firms).

Reasons set out in the AER's 2012 Envestra decision

In its draft decisions on the network proposals the AER noted that in a previous 2012 draft decision on Envestra, it had set out its reasons for the decision not to include liquidity costs, and that 'neither [the network proposals] nor Incenta has engaged with the reasons set out in this decision'.[19] One of the reasons set out in the AER's 2012 draft decision was that recognising liquidity costs was not appropriate given the favourable timing assumptions in the AER's PTRM formula. This issue has already been considered separately above.

Other matters raised in the Envestra decision related to assumptions that had been applied by Envestra's adviser. We consider that none of these objections is valid in relation to our approach. The AER stated that:[20]

- The imputation payout ratio should be applied rather than the dividend payout ratio – we have applied the imputation payout ratio consistent with the AER's approach;
- The expected capital expenditure may significantly reduce under an adverse market scenario – we tested this proposition with staff at Standard & Poor's, who told us that in its own calculations it assumes the stated capital expenditure program will be maintained;[21]
- Distributions would be reduced/removed under an adverse market scenario – however, in its own estimates Standard & Poor's assumes that the consistent dividend policy is maintained.[22]

In summary, the AER proposed that if the working capital allowance implicit in the PTRM formula was to be included in the calculation of liquidity ratios, 'then using Envestra's calculation method, an allowance for liquidity would not be required.' The problems with this approach are that:

- Standard & Poor's formula only includes *net* working capital as a source of liquidity; and
- We find that on average the committed undrawn bank lines for United Energy would need to be in the order of $130 million, which is more than a quarter of the annual regulated revenue requirement, and is clearly much larger than any implicit net working capital allowance might be.

3.6 Conclusion on the AER's draft decision

In conclusion, whilst we agree with some technical issues raised by the AER, and have adjusted our methodology to accommodate these changes, we do not agree with the AER's rejection of liquidity costs and three month ahead financing costs. All three cost components are part of the benchmark costs that would be incurred by a benchmark regulated business. The fact that some of these costs

[19] AER (November, 2014a), p. 3-329; AER (November, 2014b), p. 3-315; AER (November, 2014c), p. 3-324.

[20] Australian Energy Regulator (September, 2012), p.201.

[21] Capex programs can rarely be instantly curtailed, and such action would usually incur significant cancellation penalties, along with longer term reputation penalties that could hamper future contracting.

[22] Firms are reluctant to cut dividends due to the share price signal that this implies. Regulated utilities are even less likely to cut dividends as their shareholder clientele purchases their shares specifically for their relatively high and stable dividend yield.

have not been identified or requested by some businesses does not change the fact that they are benchmark efficient costs. Furthermore, under the NER, regulated businesses are obliged to forecast the prudently incurred efficient costs of a benchmark business, and the AER is obliged to assess whether these costs are prudent and efficient. As we have estimated these costs based on benchmark evidence and principles, we consider that they are both prudent and efficient.

4. Estimating total debt raising costs

4.1 Benchmark debt-issuing transaction cost allowance

4.1.1 The PwC (2013) benchmarking report

As noted in our previous reports, the benchmark assumption implicit in all Australian regulatory decisions, is that 100 per cent of RAB debt portfolio is comprised of bonds. To estimate transaction costs associated with bond issues we again rely on the PwC (2013) analysis, which is based on recent observations of market practice, and has been accepted by the AER.

These estimates are based on interviews with legal firms, banks and credit rating agencies that facilitate the bond raising process, and charge fees for doing so. PwC's list of bond issuance transaction costs for a benchmark bond issuance program is shown in Table 1.

Table 1: Other bond issuance transaction costs

Cost item	Unit	Estimated value	Source
Legal counsel – Master program	Per 10 years	$56,250	Legal firms
Legal counsel – issuer's	Per issue	$15,625	Legal firms
Credit rating agency – Initial credit rating	Per issue	$77,500	Rating agencies
Credit rating agency – Annual surveillance	Per annum in total	$35,500	Rating agencies
Credit rating agency – Up front bond issue	Per issue	5.2bps of issue size	Rating agencies
Registrar – Up front	Per 10 years	$20,850	Banks
Registrar - Annual	Per annum per issue	$7,825	Banks
Investment bank's out-of-pocket expenses	Per issue	$3,000	Estimated

Source: PwC (2013), p.19.

The individual components are:

- *Legal counsel – Master program* –legal costs for preparing a Master Program (the base document for multiple issuances over the next 10 years);
- *Legal counsel – issuer's* – legal fees for preparing documents under the Master Program;
- *Credit rating agency – Initial credit rating* – fee to establish a credit rating;
- *Credit rating agency – Annual surveillance* – annual rating agency fee for maintaining the credit rating;
- *Credit rating agency – Up front bond issue* – fee charged by the rating agency when a new bond is issued;
- *Registrar – Up front* – initial set-up fee charged by the bond registry;
- *Registrar – Annual* – annual fee charged by the registry service; and

- *Investment bank's out-of-pocket expenses* – fees charged by the agents of a bank for travel, accommodation, venue hire, printing etc.

PwC's survey of recent debt issuance by infrastructure businesses found that the standard bond issuance size is now $250 million, which is also agreed by the AER. United Energy's Regulated Asset Base (RAB) is $2,070 million, and with benchmark gearing at 60 per cent, its benchmark debt level is $1,242 million. This implies that the benchmark firm would need 5 bond issues of $250 million to refinance its debt.

4.1.2 Estimating United Energy's benchmark debt-issuing transaction cost allowance

PwC estimated that Australian businesses issuing bonds in the US incur an arrangement fee of approximately 8.5 basis points per annum (bppa).[23] As noted in section 3 above, the AER adopted a slightly lower levelised benchmarks of 7.38 bppa to 7.53 bppa due to applying its estimated nominal vanilla WACCs of 6.8 per cent to 7.24 per cent, rather than the generic 10 per cent that PwC applied in its study. We agree with the AER's approach, but consider that a range of 7.38 bppa to 7.53 bppa is too low for a WACC of 6.80 per cent to 7.24 per cent, and that values in the range of 7.55 bppa to 7.68 bppa would be more appropriate when applying that WACC.[24] Applying United Energy's estimated WACC of 7.38 per cent, we estimate that the arrangement fee component is 7.72 bppa on a levelised basis. In Table 2 we find that by applying PwC's benchmark cost estimates, the benchmark debt-raising transaction cost estimate is 9.8 basis points for one bond issue of $250 million, and a cost of **9.1 basis points per annum** (bppa) for United Energy's estimated 5 benchmark bond issues.

Table 2: United Energy – benchmark debt-raising transaction costs (bppa)[25]

Number of bonds	Value	1 bond issued	5 bonds issued
Amount raised		$250 million	$1,250 million
Arrangement fee (bppa)		7.72	7.72
Bond Master Program (per program)	$56,250	0.30	0.08
Issuer's legal counsel	$15,625	0.08	0.08
Company credit rating	$77,500	0.41	0.10
Annual surveillance fee	$35,500	0.14	0.04
Up-front issuance fee	5.20 bp	0.70	0.70
Registration up-front (per program)	$20,850	0.11	0.11
Registration - annual	$7,825	0.31	0.31
Agents out-of-pockets	$3,000	0.02	0.02
Total (bppa)		**9.81**	**9.12**

Source: Based on PwC (2013), p.19, Incenta

---

23 PwC, (June, 2013), p.77.

24 The value of 7.72 basis points is obtained by applying a WACC of 7.38 per cent to calculate the levelised basis points taking account of the arrangement fees and terms to maturity of the bonds used in the sample (i.e. bonds where the Prospectus provided to investors revealed the arrangement fee component).

25 Since the costs are expressed in basis points per annum (bppa), each year they will vary in proportion to the benchmark debt that is forecast for the regulated business.

4.1.3 Conclusion - United Energy's benchmark debt-issuing transaction cost allowance

Based on PwC's benchmark estimates of costs associated with bond issues, we estimate that a benchmark firm with United Energy's characteristics would incur a levelised cost of **9.1 bppa** to issue bonds.

4.2 Allowance for costs associated with the Standard & Poor's liquidity requirement

As discussed in section 3 above, the NER require the AER to assess whether identified costs are 'the costs that a prudent operator would require to achieve the operating expenditure objectives'. In our previous reports we reported that we had discussed the matter of liquidity costs with Standard & Poor's, and that its staff had confirmed to us that Standard & Poor's considers liquidity costs to be direct costs that are no different from other direct costs associated with debt raising, and considers that most regulated energy transmission and distribution businesses will incur these costs. The AER has recognised other costs associated with debt raising, and liquidity costs are similarly a cost that is borne by the benchmark firm.

4.2.1 Approach to estimating the cost of maintaining a liquidity reserve

In order to create and maintain a liquidity reserve, it is most efficient to secure and retain bank debt facilities that are committed (meaning that they can be drawn upon immediately as needed) but undrawn. As noted in our previous reports, Standard & Poor's (2014) report titled, *Methodology and Assumptions: Liquidity Descriptors for Global Corporate Issuers*, describes how it assigns liquidity ratings to corporate issuers, and states that a minimum rating of 'adequate' is required in order to support an investment grade credit rating.[26] Standard & Poor's applies a forward looking estimate of the ratio of 'sources' of cash flow (designated as 'A') to the 'uses' of that cash flow (designated as 'B'), including debt re-financing to assess liquidity, with an 'adequate' level of liquidity being indicated if:

- A/B is at least 1.2x for firms generally, but must be at least 1.1x for utilities;[27] and
- If the firm's EBITDA is assumed to decline by 15 per cent compared with the base case forecast, A-B would still be positive.

Standard & Poor's assesses the cash flow forecasts for the business for the period 6 months ahead, and estimates the base case sources and uses of funds over that timeframe. To the extent that the liquidity requirements are not met from the cash flows, then the business would be required to supplement the 'sources' of cash until the liquidity requirements are met.

---

26 Standard & Poor's (2 January, 2014), *Methodology and Assumptions: Liquidity Descriptors For Global Corporate Issuers*, which updates Standard & Poor's earlier (28 September, 2011) report of the same title.

27 The requirement that for utilities the sources/uses ratio is 1.1x was confirmed by email from Standard & Poor's to Incenta on 25 March 2014.

Its primary concern is a scenario in which capital markets are temporarily closed, so that re-financing of debt must be undertaken based on existing cash flow sources, taking account of other uses of cash.

In its analysis, Standard & Poor's defines the sources and uses of funds as follows:

- *Sources of funds* - The major source of cash flow of a business is its Funds Flow from Operations (FFO), which may be supplemented by working capital inflows (if positive), the proceeds of asset sales, an expected cash injection from a Government shareholder or parent company, or undrawn committed bank lines. During our meeting, Standard & Poor's stated that as a general rule it would not assume that a cash injection from a Government or major private shareholder would be forthcoming. Hence, in the case of a benchmark regulated business, which is owned by a diverse group of shareholders, Standard & Poor's would not assume any such cash injection. Standard & Poor's would also expect that no proceeds are available from new debt issues or dividend reinvestment plans, since what is being modelled is a situation in which capital markets have shut down.

- *Uses of funds* – A major use of funds that is modelled is the forecast expected capital expenditure, which is derived from United Energy's PTRM. Standard & Poor's told us that it takes the view that the capital expenditure that is expected to be undertaken is actually undertaken. Other significant cash uses are debt repayments, and dividend payments. The financial health of the business pivots around the need to repay debt when it falls due. The position of Standard & Poor's is that it would be difficult for the business to cut its dividend significantly in order to find the cash to repay a maturing debt.[28,29]

4.2.2 Bottom-up estimate of the costs of establishing and maintaining a liquidity reserve

Our application of the bottom-up methodology

Our approach is a bottom-up methodology that applies the formula Standard & Poor's uses to determine the minimum liquidity requirement. To estimate the benchmark level of committed undrawn bank lines for United Energy, we have undertaken a forward cash flow analysis in the same way that Standard & Poor's does. The core inputs into the forward cash flow analysis should be the benchmark outputs of United Energy's PTRM model. Using United Energy's proposal values we have estimated sources and uses as:

- *Sources of funds* – The base case Funds Flow from Operations (FFO) for each year / 6 monthly period is established by reference to the benchmark revenues, operating costs, cash taxes paid, and

28 We agree with this approach, as academic research has shown that when a regulated utility cuts its dividend, there is a disproportionately large negative share price reaction relative to industrial firms that do so (owing to fact that utilities tend to attract clienteles of shareholders who expect stable income flows).

29 The Standard & Poor's document on liquidity requirements also includes peak negative working capital in the list of cash flow uses, which reflects a concern to take account of the seasonality of cash flow. As we are calculating annual average liquidity reserves, seasonality is less of a concern (i.e., we will understate the required reserve when revenue is seasonally low and overstate it when revenue is seasonally high, but these effects will cancel out).

interest paid, all based on the benchmark gearing, weighted average cost of capital (WACC) and regulated asset base (RAB) assumptions.

- *Uses of funds* – Forecasted capital expenditure is derived using United Energy's PTRM, with dividend payments determined by the AER's intention to apply an assumed payout ratio of 70 per cent.

In order to estimate the level of new debt financing required in any regulatory year we have taken the level of capital expenditure plus the net change in the RAB due to depreciation and inflation indexation[30] – the level of refinancing of existing debt requires assumptions about the timing of historical debt issuances. The higher the level of debt financing assumed, the lower the ratio of sources to uses of funds, and the higher the amount of committed undrawn bank lines that is required (and hence, the higher the costs associated with Standard & Poor's liquidity requirement). We have assumed that the quantum of debt to be refinanced in regulatory year t is equal to the average of the following two proxies:

- the sum of the new debt raising in year *t-10* (that is, the capital expenditure and net change in the RAB in that year) and 10 per cent of the opening RAB for that year, and

- 10 per cent of the closing RAB for year *t-10*.

Our specific rationale for this assumption was demonstrated in our previous reports.[31] In order to estimate the cost of a liquidity reserve, it is necessary to calculate:

- The quantum of the liquidity reserve (i.e. commitments of bank debt) implied. That is, the committed but unused bank debt required in the event of a liquidity crisis;

- The commitment fee that charged by banks to hold the bank debt that is available in the event of a liquidity crisis; and

- Finally, the upfront fee charged by banks and associated costs to establish the liquidity reserve bank debt facility (i.e. the 'establishment fee' and other transaction costs).

The quantum of the required liquidity reserve

In Table 3, we estimate the value of committed but undrawn bank lines required to meet the liquidity ratios ranges from $107.4 million to $146.3 million over the next regulatory period. This equates to between 6.5 per cent and 11.2 per cent of benchmark debt. We find that the first limb of Standard & Poor's liquidity requirements is satisfied overall.[32]

30 This net change will be positive if the indexation component exceeds the depreciation allowance, and will be negative if the indexation component is less than the depreciation allowance (it would be expected to be negative provided that inflation rates remain modest).

31 Incenta (May, 2014a), pp.12-13; Incenta (May, 2014b) pp.12-13; Incenta (June, 2014), pp.15-16.

32 We calculated the NPV of the bank lines required applying United Energy's average nominal vanilla WACC of 7.38 per cent, and found that the first limb (sources/uses >1.1) dominated.

Table 3: United Energy – bank lines required to satisfy S&P's liquidity requirement (sources/uses test) forecasting 6 months ahead ($million, $nominal)

PTRM model outputs:	2016	2017	2018	2019	2020
Revenue (Smoothed)	220.1	225.6	231.3	237.1	243.0
Operating costs	77.5	80.9	83.5	87.0	88.5
EBITDA	142.6	144.7	147.8	150.0	154.5
Sources:					
EBITDA	142.6	144.7	147.8	150.0	154.5
Less, Cash taxes	23.9	21.3	18.5	16.1	16.2
Less, Interest paid	34.0	36.9	40.0	42.6	45.7
Funds From Operations	84.7	86.5	89.2	91.3	92.6
Plus, Proceeds of asset sales	-	-	-	-	-
Total Sources (not incl. committed but unused bank lines) [A1]	84.7	86.5	89.2	91.3	92.6
Total Sources (not incl. committed but unused bank lines) EBITDA falls 15% [A2]	70.1	71.7	74.0	76.0	76.9
Uses:					
Expected capital spending	122.4	134.1	134.5	122.2	116.3
Plus, Debt repayments	42.2	42.9	39.5	52.6	39.1
Plus, Dividend payments	39.1	34.7	30.3	26.3	26.4
Total Uses [B]:	203.6	211.7	204.3	201.1	181.9
Committed undrawn bank lines [C] required for (A1 + C) / B = 1.1x	139.3	146.3	135.5	129.7	107.4
Undrawn bank lines as % of debt	11.2%	10.9%	9.3%	8.3%	6.5%
Undrawn committed bank lines for A2-B = 0 when EBITDA falls 15%	133.5	140.0	130.2	125.0	105.0
Undrawn committed bank lines as % of regulatory debt	10.8%	10.4%	9.0%	8.0%	6.4%

Source: United Energy data and Incenta analysis

We have assumed that both the revenue (smoothed), and the operating costs include the value of debt raising costs, however these cancel out at the EBITDA line. Hence, there is no circularity from using revenue and operating cost forecasts that are inclusive of debt raising costs.

The commitment fee

In order to establish a line of credit from banks it is necessary to pay a 'commitment fee', and according to the PwC (2013) report, the current market practice is for banks to charge at a rate of 50 per cent of the margin over the swap rate that the bank would charge for lending the funds. We have estimated the cost of the commitment fee to be 70 basis points for the required bank facility, which is half of the spread between the 3 year Bloomberg BBB yield (as a proxy for the cost of bank debt) and the 3 year swap rate.

Table 4: United Energy – Calculation of commitment fee (20 days to 30 January, 2015)

	Fee per annum
Bloomberg 3 year BBB yield	3.80%
AUD 3 year swap rate	2.40%
Bloomberg 3 year implied margin (proxy for bank debt margin)	1.41%
Commitment fee (50 per cent of margin)	**0.70%**

Source: Bloomberg and Incenta analysis

The annualised commitment fees for a firm with United Energy's benchmark characteristics are shown in Table 5. The bank facility required each year to support committed but unused bank lines in order to satisfy Standard & Poor's liquidity requirements (as calculated in Table 3 above) convert to a commitment fee (in dollars based on the 0.70 per cent per annum calculated in Table 4), which in turn convert to a basis points per annum fee (based on the outstanding debt component of the RAB). The commitment fee is found to range from $0.75 million to $1.03 million per annum, or between 4.6 basis points and 7.9 basis points on a levelised basis.

Table 5: United Energy – benchmark bank facility commitment fees (basis points per annum)

	2016	2017	2018	2019	2020
Debt (60% of RAB) ($m)	1,242.1	1,346.6	1,451.8	1,554.8	1,652.3
Bank facility required ($m)	139.3	146.3	135.5	129.7	107.4
Commitment fee ($m)	0.98	1.03	0.95	0.91	0.75
Commitment fee (bppa on regulatory debt)	**7.9**	**7.6**	**6.5**	**5.9**	**4.6**
Levelised cost (bppa)	**6.5**				

Source: PwC (2013) and Incenta analysis. Note: Commitment fee ($m) is calculated as benchmark rate of 0.70 per cent per annum, multiplied by the annual committed but unused bank facility required ($m).

Establishment fee and other transaction costs associated with establishing the bank debt facility

The third input required to calculate the cost to maintain a liquidity reserve is the upfront cost of establishing the bank debt facility. We have again adopted the benchmark values estimated by PwC, which come to an annualised amount of $189,780 for 2016, or approximately 1.53 basis points.[33] The derivation of these amounts is shown in Table 6.

33 PwC (June, 2013), p.iv.

Table 6: United Energy – establishment fee and other transaction costs associated with establishing a committed but unused bank debt facility for a debt portfolio of $1,242 million (2016)

	Basis	Cost	Annual	Bppa	Source:
Establishment fee	Up-front	236,758.11	$90,843	0.73	PwC (2013): 0.17% x quantum of bank debt ($139.3 million, annualised with 7.38% discount rate
Other bank transaction costs:					
-legal counsel – borrower	Up-front	$86,667	$33,254	0.27	PwC (2013): annualised with 7.38% discount rate
-legal counsel – bank	Up-front	$90,000	$34,533	0.28	PwC (2013): annualised with 7.38% discount rate
-Syndication fee	Per annum	$30,000	$30,000	0.24	PwC (2013): annual syndication fee
-Bank's out-of-pockets	Up-front	$3,000	$1,151	0.01	PwC (2013): annualised with 7.38% discount rate
Total Annual Equivalent			**$189,780**	**1.53**	**Basis points per annum**

Source: PwC benchmark values and Incenta analysis Note: United Energy's estimated average WACC of 7.38% per cent was applied.

Table 7 shows how the establishment fee and other transaction costs vary with the bank facility required during each year of the regulatory period. The maximum annualised cost is $194,377 in 2017 (coinciding with the highest liquidity requirement of $146.3 million in that year), implying a 1.44 basis points per annum cost based on regulatory debt. On a levelised basis, using United Energy's 7.38 per cent discount rate, we estimated an establishment fee and other costs component of 1.29 basis points per annum.

Table 7: United Energy – establishment fee and other transaction costs (basis points per annum)

	2016	2017	2018	2019	2020
Establishment fee (annual equivalent)	90,843	95,440	88,358	84,594	70,062
Other bank transaction costs	98,937	98,937	98,937	98,937	98,937
Total annual equivalent costs ($)	189,780	194,377	187,295	183,532	169,000
Total annual equivalent cost (bppa)	**1.53**	**1.44**	**1.29**	**1.18**	**1.02**
Levelised cost (bppa) on regulatory debt	**1.29**				

Source: PwC (2013) and Incenta analysis. Note: Annual equivalent cost (bppa) is calculated as a portion of regulatory debt for each year.

4.2.3 Benchmark cost of establishing and maintaining a liquidity reserve

In Table 8 we estimate the benchmark cost of establishing and maintaining the liquidity reserve needed to meet Standard & Poor's liquidity requirements. This cost is estimated to be between $0.92 million $1.22 million, which converts to a levelised cost of **7.8 basis points per annum** on the regulatory debt.

Table 8: United Energy – Total establishment fee and other transaction costs associated with establishing a committed but unused bank debt facility

	2016	2017	2018	2019	2020
Commitment fee (annual equivalent) ($)	0.98	1.03	0.95	0.91	0.75
Establishment fee & other costs ($)	0.19	0.19	0.19	0.18	0.17
Total annual equivalent costs ($)	1.17	1.22	1.14	1.09	0.92
Total annual equivalent cost (bppa)	**9.4**	**9.1**	**7.8**	**7.0**	**5.6**
Levelised cost (bppa) on regulatory debt	**7.8**				

Source: PwC (2013) and Incenta analysis

4.3 Costs associated with re-financing 3 months ahead

4.3.1 Estimating the cost of 3 month ahead financing

As noted in our previous reports on this issue, we consider that the methodology applied by PwC to estimate the cost of re-financing bonds 3 months ahead of their maturity is fundamentally sound. PwC (2013) had argued that:[34]

> *While the entity may actually invest in BBSW or Commonwealth Government bonds, and that will create a cash shortfall, on the other hand the entity gains from adding a lower risk asset to its portfolio. This offsetting economic effect can be neutralised by assuming that the business receives the 3 month BBB+ yield.*

PwC (2013) found that the annual net cost of re-financing one-tenth of this portfolio three months ahead was 4.7 basis points, which was the net outcome of:[35]

- A three month interest cost borne on the newly issued bond, of 16.6 basis points; less
- The three month interest that could be earned on BBB rated debt, which was 11.9 basis points.

In section 3.4 above, we agreed with the AER that it is not consistent to apply a trailing average cost of debt to estimate the cost of 3 month ahead financing, since it is the rate of return on the new debt that is issued that is the cost that is partly offset by investment in short term bonds.

In Table 9 we have used a cost of debt assumption of 5.67 per cent, which is sourced from United Energy,[36] and have assumed re-investment for 3 months in a BBB rated bond at 3.62 per cent. It is not clear that this approach would over-estimate the 3 month ahead re-financing estimate relative to using a spot rate based on 10 year BBB+ fixed rate debt. However, the offsetting 'benefit' is based on the 6 month Bloomberg FVC yield, as it is the closest available estimate of a 3 month yield (since Bloomberg currently does not publish a 3 month yield). This results in an early re-financing cost of 10.3 basis points per annum, which is expected to be a conservative estimate, since the 6 month BBB yield estimate is expected to be an over-estimate of the 3 month yield. Hence, we consider that any over-estimate that might arise from applying United Energy's cost of debt approach would be likely to

34 PwC (June 2013), p. 11.

35 PwC (June, 2013), p. 25.

36 For this purpose, United Energy instructed us to apply the cost of debt for 2016 that it has applied as part of its cost of capital proposal based on a 20 day averaging period ending 30 January, 2015.

be offset by our conservative approach of estimating the 3 month BBB yield with 6 month BBB yield data from Bloomberg.

Table 9: Bond re-financing cost summary for $250 million bond (20 business days to 30 January, 2015)

Calculation element	Upfront cash cost for $250m ($m)	Cost for $1,242 debt portfolio (bppa)
3 month interest cost on new bond	3,541,290	
3 month BBB credit rated interest income	-2,260,003	
Total cost if invested in BBB credit risk and no redemption/buy back	**1,281,287**	**10.3**

Source: Bloomberg, and Incenta analysis applying PwC (2013) methodology to United Energy's cost of debt assumption

In Table 10 we find that the establishment fee and other costs range from $0.40 million to $0.54 million, which convert to a range of 2.4 to 3.5 basis points per annum, or a levelised **3.1 basis points per annum** on regulatory debt over the period.

Table 10: United Energy – Total cost of 3 month ahead re-financing

	2016	2017	2018	2019	2020
Maturing component of debt portfolio ($m)	84.4	85.7	78.9	105.2	78.3
Establishment fee & other costs ($m)	0.43	0.44	0.40	0.54	0.40
Total annual equivalent cost (bppa)	**3.5**	**3.3**	**2.8**	**3.5**	**2.4**
Levelised cost (bppa) on regulatory debt	**3.1**				

Source: PwC (2013) and Incenta analysis

4.4 Total debt-raising transaction costs

In this section we sum the three sources of debt-raising transaction costs, and combine them to calculate the levelised cost (in basis points per annum) relative to benchmark forecast debt values taken from United Energy's PTRM.

In Table 11 below we show the estimated total dollar value debt raising transaction costs (ranging from $2.7 million to $3.1 million) and the equivalent values in terms of basis points per annum, based on the regulatory debt. The total levelised debt raising transaction cost is **20.0 basis points per annum.**

Table 11: United Energy – total debt raising transaction costs (basis points per annum)

	2016	2017	2018	2019	2020
Debt raising transaction costs ($m)	1.1	1.2	1.3	1.4	1.5
Liquidity - commitment fee ($m)	1.2	1.2	1.1	1.1	0.9
3 month ahead financing costs ($m)	0.4	0.4	0.4	0.5	0.4
Total debt raising transaction costs ($m)	**2.7**	**2.9**	**2.9**	**3.1**	**2.8**
Debt raising transaction costs (bppa)	9.1	9.1	9.1	9.1	9.1
Liquidity - commitment fee (bppa)	9.4	9.1	7.8	7.0	5.6
3 month ahead financing costs (bppa)	3.5	3.3	2.8	3.5	2.4
Total debt raising transaction costs (bppa)	**22.0**	**21.4**	**19.7**	**19.6**	**17.1**
Levelised debt raising transaction costs (bppa)	**20.0**				

Source: United Energy data and Incenta analysis