Fixed Cost of Best New Entrant Peaking Plant for the Calendar Year 2009

Consultation Per AIP/SEM/08/083

Response from AES

1ST August 2008

Introduction and Summary

1. AES welcomes the opportunity to comment on the proposed BNE price for 2009 for determining capacity payments. To assist with this response, we have commissioned independent reviews of the proposals for capital costs by Mott MacDonald Pettit (MMP) and of the financing costs by Professor J R Davies of Strathclyde University. Their reports are included as appendices to this response.

2. Given that energy bids are restricted to SRMC, the capacity payment is a very important revenue component for investments in both peaking and base load technology. Combined with ancillary service payments, it represents 100% of gross margin for a peaking plant and typically 40-50% of gross margin for a base load plant. The determination of the underlying capital, financial and operating costs by the SEMC must therefore be transparent, fair and reasonable to attract investment from new entrants.

3. In most mature markets there is normally a dispute resolution mechanism if a company is unable to accept proposed regulated prices. In the UK such issues are resolved by the Competition Commission. Unfortunately the SEM legislation does not presently include such a provision. Whilst the SEMC has a public duty to properly consider all representations made to it, it is not bound to accept them. AES views this as a material weakness in the design of the SEM legal framework. At a time when consumers are already experiencing sharp increases in fuel prices, AES is concerned that the absence of a proper check mechanism for regulated capacity payments could result in an outcome which is not fair and reasonable for generators.

4. The proposed BNE price of €81.24/kw/yr represents an increase of 1.84% from the 2007 value. At a very basic level, this does not seem credible because (i) EPC prices have continued to increase steeply throughout 2007 and 2008, (ii) operating costs have increased annually by at least inflation, and (ii) the increased volatility in capital markets has made it increasingly difficult to finance projects. A 1.84% increase in the BNE price looks suspiciously close to inflation.

5. Under the SEM rules, all plants are remunerated based on the marginal costs for both energy and capacity. Given this design, an established portfolio player may benefit materially from a sharp increase in BNE prices, if the average historic investment cost of its portfolio is lower than current investment costs. Further gains may be realised from free carbon credits[1]. The same cannot be said however for a new entrant, particularly if they are considering investment in base

[1] In the absence of a PPA clause which allocates this benefit to consumers.

load capacity[2]. The effect of sharp increases in the cost of new capacity may well be an undesirable and unanticipated outcome of the SEM design. Rather that trying to control this outcome however, the SEMC may need to review the SEM high level design and underlying industry structure and re-consider what might be required to deliver meaningful competition.

6. The paper refers in places to the use of consultants to help determine capital, financing and operating costs. Given the specialised technical issues involved in these areas, it is disappointing that the SEMC has not directly published this work. We would consider this to be normal and good practice. It provides for full transparency, facilitates detailed and intelligent responses and ultimately a comprehensive "gap analysis" between the proposals and counter-proposals.

7. Based on the advice provided by our consultants and our own analysis, we are of the view that the proposals for capital, financing and operating costs need to be increased as set out in the table below:

	SEMC Estimate	**AES Estimate**
Capital Costs	€84.3m	€148m
Annual Fixed Costs	€4.6m	€9.7m
WACC	7.24%	9.96%
BNE Cost (€/kw/year)	81.24	176.06

8. Given the materiality of the gaps in these estimates, further discussion and analysis is essential before any final decision is made. In previous consultations on BNE costs, we have felt that the responses to our comments provided by the SEMC in decision papers were inadequate. For example, the BNE decision paper on the 18th May 2007 commented:

   "Given these matters and the comments raised regarding the market return and gearing ratios used in calculating the WACC, the Regulatory Authorities have had the proposed WACC reviewed by independent verification which has concluded that the settings described are credible for the WACC calculation and consequently the Regulatory Authorities do not consider a lower level of gearing or any other adjustment resulting in a higher WACC is necessary"

   It would have been very helpful if the SEMC had published this independent verification.

[2] New entry base load plants considered today may not be operating until after 2012, by which time it is widely expected that all carbon credits will to be auctioned.

Technology Options

9. *Unit Size:* The size of the all-island system, together with the number of relatively large units and the degree of anticipated wind generation, would suggest that smaller peaking units with short periods to start and achieve full load are required. We are surprised that a time to full load of 20 minutes is considered sufficient. These smaller units have higher specific costs and, if they are required, this differential will have to be captured somewhere, either in the capacity payment or in ancillary services payments.

10. The BNE calculation deducts the same amount for ancillary services for all capacity. The review of ancillary service payments points to a material variation in ancillary service payments between generating units depending on the varying quality of service. Consideration needs to be given to this.

11. *Technology Costs:* The graph on page 12 of the paper considers relative total costs at different capacity factors. Given however that the anticipated capacity factor is close to zero in the unconstrained dispatch, it is difficult to understand the relevance of this comparison.

12. *Forced and Planned Outage Rates:* Although the unconstrained dispatch indicates almost zero dispatch, given the degree of wind generation, in practice peaking units may incur higher constrained-on capacity factors. This in turn will result in higher planned and forced outage rates that what is suggested.

13. *Fuel Choice:* An investor will lose money if he invests in a gas-fired peaking plant because he is unable to include the fixed cost of gas transportation in energy bids and this cost is not included in the annualised BNE price either. However there is also a material risk that, over the investment lifetime, a distillate-fired peaking plant with a high SRMC will become uncompetitive if the SEM market amalgamates with the UK market. The SEMC could address this issue by nominating a gas-fired plant as the BNE or by allowing the inclusion of fixed gas transportation costs in energy bids.

Economic and Financial Parameters

14. We asked Professor J R Davies ("JRD") of Strathclyde University to review this section of the consultation paper. His comments can be found in appendix 1. Professor Davies makes it clear that his thoughts are "*preliminary and tentative*" at this stage, commenting that "*one limitation of the consultation paper is the failure to explain fully the basis of some of the proposed estimates for the parameters in the model being employed*". Against this background we would encourage the SEMC to publish the advice it received in this area to facilitate a more informed and comprehensive debate. In the meantime, we would offer the following comments:

Appropriate Data Sources:

15. The SEMC is proposing to use single points in time to measure the risk free rate and the cost of debt. However the parameters for the equity risk premium and beta are based on historic time series. There is strong empirical evidence that the CAPM parameters and costs of debt are inversely correlated. At a time of high market volatility the equity risk premium rises and at the same time the yield on risk free assets falls as investors re-allocate their portfolios. In this case the SEMC is proposing to reduce the risk free rate from last year's value but to maintain the same equity risk premium and beta. This approach is internally inconsistent. It may be more appropriate to maintain all elements of the CAPM formula as the long-term average of a historic time series and this method should be reproducible in future years.

16. The SEMC proposes using an asset beta of 0.60 for this investment in a peaking plant because it considers that this value is "*in line with international estimates of an asset beta, which generally range from 0.5 to 0.8 for generators*". It is difficult to comment in any detail on the relevance of this range for this project because the source of the data is not revealed. We suspect that it may relate mainly to regulated utilities with investments in transmission and distribution assets as well as generation assets. If this is the case, then the range must be used with caution because the risks associated with regulated T+D assets are considerably lower that those associated with generation assets. We must further consider the difference in the regulation of the capacity payment compared to typical utility regulation. For example the capacity payment is subject to the cyclicality associated with EPC prices and there is no guarantee that the regulatory mechanism will survive the 15-year investment period.

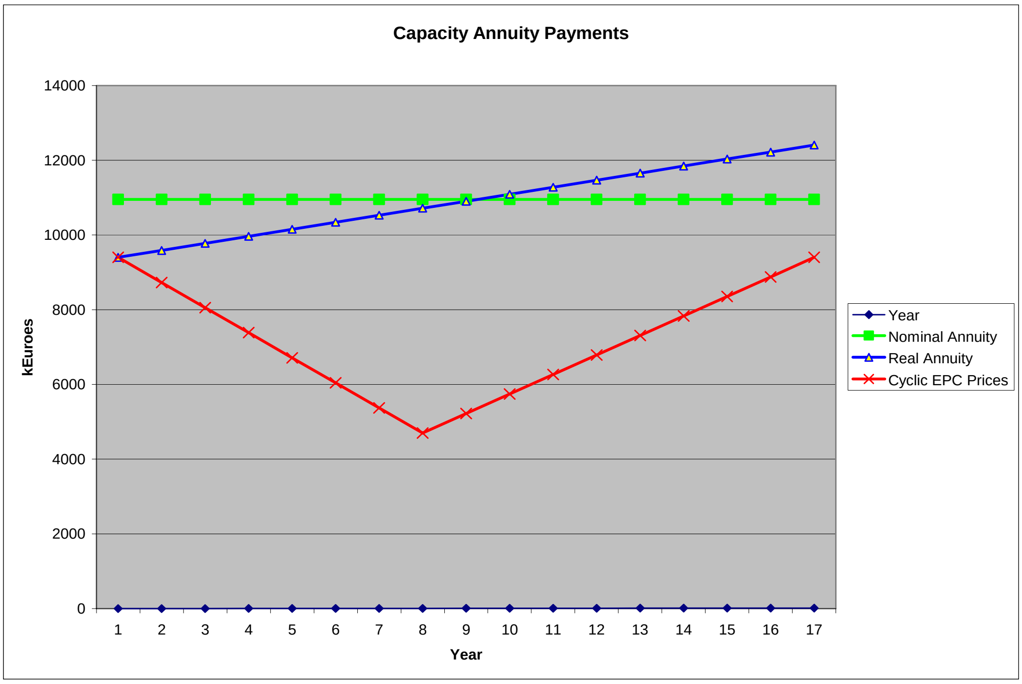
Equity Risk Premium:

17. JRD comments on the Competition Commission's assessment of the equity risk premium in its Heathrow Gatwick inquiry, stating that "*with market conditions now quite different the estimates of the risk premium is likely to be somewhat higher*".

Asset Beta:

18. The paper refers to international estimates of 0.5-0.8 for generators, but there is no reference to the relevant evidence to support this. The paper goes on to propose an asset beta of 0.6, in the lower half of the range, without providing a rationale for the judgment. JRD notes that the relevant beta is not that for the international generating sector but for this particular project. He points to the following material risks with the project:

- The capacity payment is based on a real annuity, rather than a nominal annuity. However lenders lend on a nominal basis. The risk here stems from the fact that the SEMC reviews the underlying costs which make up the capacity payment on an annual basis. If these costs do not increase in line with inflation for 15 years, then the investment is exposed[3]. We have seen that historic EPC prices have been cyclic and EPC prices today are more than twice what they were in 2003. Many observers consider that we the present cycle may peak in the near future and that prices could fall significantly thereafter for several years. The graph below illustrates the risks investors face with cyclic movements in EPC prices.



- The capacity "pot" is derived on the basis of "required margin" above peak demand. This required margin is set by the SEMC at less than 5 percent. Therefore there is a risk that the specific capacity payments could be materially diluted.

- Finally there is an ultimate risk that the capacity payment mechanism could disappear at some point in the future, leaving a high SRMC distillate-fired peaker uneconomic in an energy-only market.

These risks no not exist for most regulates industries that are subject to periodic (typically 5-yearly) price control reviews.

[3] Even using a real annuity, this should be increased by inflation to reflect cost increases during the year.

19. Brealey and Myers[4] also point out that cyclical firms tend to be higher-beta firms:

> *"This means that cyclical firms – firms whose revenues and earnings are strongly dependent on the state of the business cycle- tend to be high-beta firms. Thus you should demand a higher rate of return from investments whose performance is strongly tied to the performance of the economy".*

The risks associated with this project therefore might suggest an asset beta of at least 0.80.

Gearing:

20. The paper states that "u*sually a company finances its projects with the same gearing as its current operations*". The paper provides measures of book gearing for three companies which have generating businesses operating in the SEM and states that the SEMC considers that a 70% gearing is achievable for "*generating companies and projects alike*". We see a number of issues with this analysis:

    - First, companies do not usually finance projects with the same gearing as its existing average. JRD explains that "*analysis based on a company maintaining its asset base over time is not applicable to a project, such as the provision of an increment of generating capacity*". This approach would also amount to cross-subsidy which is prohibited in the SEM. All three companies quoted have significant transmission and distribution assets which are considered as lower risk that generating assets and subsequently have higher debt capacities.

    - Second, there are several ways in which gearing can be calculated. The examples given calculate book gearing based on (current liabilities + long-term liabilities) / assets. However gearing is usually measured as long-term debt / total long-term capital. In the case AES this would reduce book gearing from 80% to 64%.

    - Finally, JRD points out that in the in the Heathrow Gatwick inquiry, the rating agencies made it clear that debt to RAB was not the only factor to be taken into account. Qualitative and other ratios particularly the interest cover ratio had to be considered. The Competition Commission concluded that the cost of capital should be based on an assumed debt to RAB ratio of 60 percent. JRD points out that for companies involved in the provision of generating capacity, EBITDA (or gross margin) is expected to be at least 1.50 times the debt service payments for each year of the loan, with an average value of the ratio over the lifetime of the loan being in excess of 1.60.

[4] "Principles of Corporate Finance", Fourth Edition, by Richard A. Brealey and Stewert C. Myers, page 199.

21. To demonstrate this last point, we constructed a financial model to determine the likely level of debt that might be obtainable for this investment. The results of this can be seen at appendix 2[5]. The model calculates the level of gearing which is achievable for assumed average required debt service cover ratios (DSCRs) of 1.60, 1.80 and 2.00. Expected revenues and costs are set at prudent levels to reflect the approach that a bank would typically employ. Revenues in year 1 (capacity payments and ancillary service payments) and operating costs are as proposed by the SEMC[6]. Operating costs are then increased by inflation. The capacity revenue is split out to reflect the annuity for the capital cost and the annuity for operating costs. The annuity for operating costs is increased each year by inflation. To reflect expected continued volatility in EPC prices, the capacity payment is reduced to 50% over a period of 7 years and then increases again over the remaining 8 years back to today's level. The resulting gearing achievable are 39% for a DSCR= 1.60, 35% for a DSCR of 1.80 and 31% for a DSCR of 2.00.

Corporation Tax Rate:

22. There are three reasons why it is incorrect to use the CTR applicable to the RoI.

    - First, the SEMC recognises in this consultation paper that energy is an international business, and it proposes using an asset beta of 0.60 to calculate a pre-tax WACC, considering this to be "*in line with international estimates of the asset beta, which generally range from 0.5 to 0.8 for generators*". International estimates of the asset beta will be based on international parameters including international tax rates. It is therefore inconsistent to use the tax rate from one particular country for the calculation of pre-tax WACC.

    - Second, a CTR of 12.5% is only applicable for a company registered in the RoI (with no parent company registered outside of the RoI). However several SEM participants have parent companies registered outside of the RoI and this will result in a higher effective tax rate as dividends are repatriated.

    - The BNE criteria is based on the best new entry "plant", not the best new entry "company".

    The use of a RoI tax rate may also be considered discriminatory. AES would suggest that a CTR of 30%, in line with European averages would be more appropriate.

Summary:

[5] We have also send a copy of the model to the SEMC
[6] Although as illustrated later in this paper, AES considers that underlying investment costs and operating costs are much higher.

23. This is clearly a highly technical area. It was difficult to give a full and intelligent response without more detailed information, particularly in regard to data sources. The proposed of cost of capital for 2009 of 7.24% is 7.5% lower that the value used for 2008. This seems counter-intuitive given the recent volatility experienced in both the EPC markets and the capital markets.

24. We have presented arguments for a gearing of 40%, a CTR of 30% and an asset beta of at least 0.80. We are also of the view that all other CAPM parameters should be based on the long-term average of a historic average time series. By using the 2007 values for the real risk free rate, cost of debt and equity risk premium; increasing CTR to 30%; and reducing debt to 40%, AES calculates a real pre-tax WACC of 9.96%.

Investment Costs:

25. Again, one of the difficulties we had responding was the lack of transparency in exactly how the SEMC estimated each of the cost components. The SEMC does not directly publish any reports provided by technical consultants. "Base case" estimates are shown for each cost item but the paper then goes on to state that the SEMC obtained cost estimates from a number of reputable sources and that in choosing the best cost estimate it is the opinion of the committee that the mid-point value of the range received should be used. Therefore the base case total is increased by 18% from €71.465m to €84.326m. It is far from clear if the cost estimates from a number of reputable sources where for each technology considered and for each of the cost components. It would be much easier to give an intelligent response to this if the data receive from the reputable sources was published.

26. To assist with this response, AES commissioned an independent review of the proposals for capital costs by Mott MacDonald Pettit (MMP). Their report can be found at appendix 3. Our own calculation of interest during construction can be found in appendix 2. As detailed in the report, MMP has advised several clients on the capital costs for OCGT and CCGT investments in the SEM.

27. MMD estimate a total investment cost of €148m for the Siemens SGT5 200E 168 MW peaking unit. This compares to a cost of €84m proposed by the SEMC. Most of this difference arises from the cost estimates for the EPC contract, electrical interconnection and interest during construction. Clearly this difference is very material and further discussion and analysis is required to try to reconcile this.

Annual Fixed Costs:

28. The proposal for total fixed costs for 2009 is €33.6/kw. This is an 18 percent reduction in the value used for 2007 and the paper appears to provide no

explanation for this. AES has considered each of the cost components and sets out below what it considers to be appropriate estimates.

Operation and Maintenance:

29. The value proposed is €1.176m and includes a LTSA and owner's salaries. The value for 2007 was €1.34m made up of €0.564m for an LTSA and €0.776m for "owners general and administration".

30. MMP advised in its report that a typical LTSA is around 4.5% of the overall EPC price. For an estimated EPC price of €97m, this equates to €4.365m per annum.

31. This plant would be operated by two people on a 24x7 basis. This would require 12 people in total working on a 6-cycle pattern, at an estimated "fully loaded" cost of €1.2m. Three other people would be employed for general maintenance, administration and management (technical, accounting and commercial), at an estimated "fully loaded" cost of €0.4m.

32. Further costs would include security and general admin, estimated at €0.3m per annum.

33. Estimated total O+M costs are therefore over €6m.

Transmission Charges:

34. Transmission charges were €0.97m in 2007 and are proposed at €0.916m for 2009. This reduction may be justified by the reduction in the net capacity of the BNE plant. As noted by the SEMC, re-evaluation of this may be necessary following harmonization of TUoS charges.

Insurance and Miscellaneous Costs:

35. These costs were €1.836m in 2007 and the proposal for 2009 is €1.008m. In our experience insurance premiums for power plants have stayed constant over the last year or so in real terms. We can see no reason whatsoever for this proposed material reduction. The small reduction in the size of the plant would make no difference to the premium.

Rates

36. The cost for 2007 was €1.854m and the proposal for 2009 is €1.315m. Rates are expected to increase by at least inflation for 2009. The capacity of the BNE plant has reduced by around 7 percent but the reduction in ratable value would be offset by two years inflation.

Summary

37. AES would estimate total fixed costs in the order of €9.7m compared to the proposed estimate of €4.6m

Addressing Volatility

38. The paper comments that investors would be exposed to the same variations in EPC prices in an energy only market. We consider that the exposure will be significantly dampened in a competitive energy only market, for both investors and customers. Portfolio investors need to recover the long-run average investment cost of their portfolios. In a rising EPC market a portfolio player can invest in new capacity without needing electricity prices to fully reflect the current capacity price. This is because increased contributions will also be earned by its entire portfolio to support the new investment. The same holds in a falling EPC market if the electricity market is competitive and close to equilibrium. A new IPP player with a single plant should also experience much less volatility. However, prices may still not increase sufficiently to support new investment by a single-plant player who has no opportunity to cross-subsidise until and if he builds up a portfolio of plants over time.

39. It would be possible to amend the TSC Code such that the BNE price for the year of investment is "tagged" to individual plants. However this may introduce challenges for plants constructed pre-SEM.

40. A competitive market with several portfolio players could be introduced along the lines recommended by Deloitte a few years ago. This approach is something that the SEMC may wish to consider consistent with its powers and duty to promote competition. At the time of divestment, the exact mechanism for "tagging" existing plants could be made clear to potential buyers.

41. The option of using an "average" BNE plant is worth further consideration. This would still not eliminate the issue of year-on-year volatility however, which applies across all technologies. We would recommend than the average price is determined by a very clear and agreed process. This would involve a detailed specification and market testing. The use of the Gas Turbine World Handbook is inappropriate. These prices tend to be out of date and tend to be less than actual prices (vendor marketing needs to be discounted). Siemens, Alstom and even GE manufacture gas turbines in Europe, so the adoption of sterling or dollar exchange rates is not appropriate.

42. Using an historic time series average price may be a proxy to what might happen in a competitive market with several portfolio players. However, as explained above, this would still leave a single-plant player with some exposure.

43. We have already stated that the use of historic averages for the parameters in the CAPM formula would reduce volatility. However this does not address the underlying volatility caused by the review of EPC prices annually.

Indicative Annual Capacity Payment Sum

44. We would encourage the SEMC to fully consult on the Capacity Required determination for 2009. For previous determinations we have felt that much more detail was required to facilitate intelligent response and we would request that this is considered for 2009.

45. The indicative value for 2009 of 7,320 MWs represents a 1.5% increase from the 2008 value. This looks low given the expected demand growth.

46. Required capacity margins above peak demand are generally accepted to be in the range of 20-25%. However the required margin calculated previously by the SEMC was less than 5% above peak demand. This is just not credible. Given that actual capacity margin at present is in excess of 25%, this approach is not causing a security of supply problem in the short-term. However, a security problem can quickly materalise if the proper long-term signal is not sent to potential investors. Given the age of the existing portfolio in the SEM and the need for plant closures, the SEMC needs to give this serious consideration.

47. The low margin appears mainly to arise for the use of "ideal" forced outage rates rather than actual forced outage rates. Yet most other parameters in the determination of capacity payments are based on actuals, including investment costs. There appears to be an inconsistency therefore.

Appendix 1: Report by Professor JR Davies.

Some Observations on the Consultation Paper, "Fixed Cost of a Best New Entrant Peaking Plant for the Calendar Year 2009" (SEMC, July 2008)

The comments below relate to the section of the Consultation Paper, "Fixed Cost of a Best New Entrant Peaking Plant for the Calendar Year 2009", issued by the Single Electricity Market Committee (SEMC), dealing with the "Economic and Financial Parameters". The analysis focuses on the estimates provided for the weighted average cost of capital (WACC). The comments are preliminary and tentative thoughts on the difficult problems addressed by the Consultation Paper.

Introduction

The WACC set by the regulator should in principle correspond to the cost that a generating company will incur in raising funds to finance an investment in additional generating capacity. This cost of capital should reflect the risks that will be incurred in the investment. It is impossible to observe this cost and it is necessary to estimate its value. Such estimates have to be inferred from market data and it is necessary to specify a model to develop the inferences and then to estimate the parameters of the model. It is not possible to develop estimates with precision - there is uncertainty over the choice of model and most of the quantitative inputs required to determine a tentative value for the WACC. Despite the considerable body of research, of both theoretical and empirical nature, the specification of the cost of capital for companies and investment projects still proves to be elusive. The regulatory authorities have to exercise their judgement in choosing the appropriate model to employ and in the determination of the values to utilise in this model.

To minimise regulatory risk, and thereby minimise the required rate of return that companies will require to undertake new investment, it is essential that regulatory decisions are transparent and based on well publicised principles. It is essential that regulatory decisions are predictable once the parameters of the models being employed are specified and the basis for deriving these values is clearly defined. One limitation of the consultation paper is the failure to explain fully the basis of some of the proposed estimates for the parameters of the model being employed, such as the level of gearing that companies could employ to fund their investments and beta, the measure of risk employed in the analysis. These estimates play a critical role in determining the cost of capital.

In a comprehensive and widely quoted study of the determination of the cost of equity capital in the USA Fama and French (1997) evaluate the uncertainty associated with the estimates of the equity cost of capital. It was concluded that all estimates are likely to be characterised by substantial errors. They contend that the "large standard errors (in industry costs of equity) are driven primarily by the uncertainty about the true factor risk premiums, with some help from imprecise estimates of period by period risk loadings." Fama and French conclude even if the risk premium can be estimated without error the variation in betas, the risk measures, suggests a 95 per cent confidence interval of at least 3 per cent. They go on to refer to "woefully imprecise estimates of the cost of capital." The uncertainties in the estimation of the cost of capital suggest the regulators need to proceed with considerable caution.

The consequences of the inevitable errors in the provision of point estimates, even when these have been derived from a range of possible values, needs to be explored. The consequences of errors are asymmetrical.
Setting too low a rate may lead to under-investment and could possibly threaten the long term generation capacity whereas setting too high a value will result in higher prices for consumers and higher profits for suppliers. Given the adverse effects of an inadequate supply of electricity it is likely that consumers will be prepared to pay an insurance premium in the form of higher prices.

This point of view is particularly relevant for the determination of the cost of capital for additions to generating capacity in the electricity industry, an industry characterised by significantly higher risks than the water industry. A failure to provide adequate incentives in the form of a WACC that is commensurate with the risks of further investments in the industry poses the danger that the industry's capacity will fall below the level required to meet the future needs of consumers and industry.

It is probably advantageous to evaluate the risks associated with the specification of the cost of capital in more depth. The New Zealand Commerce Commission is one of a number of regulatory authorise that have addressed this problem. The NZCC has not only recognised the uncertainty associated with point estimates of WACC but has attempted to specify probability distributions for the estimated WACC to formally recognise the imprecision of the estimates being employed. It also recognises the consequences of errors in the value of WACC to be used for decision taking purposes. Taking this into account the New Zealand Commerce Commission specifies the value of 75th percentile of the probability distribution as the recommended basis for the WACC. Even this estimate has a 25 per cent chance of being too low if the probability distribution being employed is reliable.

Specifying the Components of WACC

1. Nominal Risk Free Rate

This is possibly the least contentious of the various estimates necessary to build up the value of the WACC. The current state of the financial markets may lead to an understatement of appropriate value for the nominal risk free rate. It is possible that yields on fifteen year bonds are being kept down at present by increasing numbers of investors seeking safety at the same time as pension funds are re-balancing their portfolios, reducing the weights given to equities and increasing the weight given to government bonds.

2. Inflation

The Consultation Paper states that “The SEMC considers the central bank’s forecast as more reliable, especially since the UK index-linked gilt is considered in over demand.” The rationale provided is simply a reinforcement of the judgement that the central bank’s forecast is more reliable. The view that index-linked gilt is considered in over demand is based on the view that the implicit expected inflation rate is too high!

3. Debt Spread

The specified debt spread fails to capture the overall cost to the borrower. The focus is on the yield to investors rather than the overall cost to the borrower – the effective rate of interest. The specified rate does not take into account the fixed charges or front end fees in setting up the borrowing arrangement. The front end cost of arranging the funding for a recent contract was as high as 175 basis points. This needs to be added to the cost of borrowing. (Though not a risk premium this is possibly the most appropriate place to recognise this issue.)

4. Equity Risk Premium

There are two main approaches employed to estimate the risk premium, one uses historical returns while the other derives the expected return on the market as the implied yield on the market given forecasts of expected dividends. The most commonly employed approach uses the historical return on the market minus the risk free rate of interest (see Siegel (1992), Ibbotson (2001) and Dimson, Marsh and Saunton (2002, 2005, and 2007). Whilst straight forward to apply it has to contend with the problems of assessing the relevance of historical data for future time periods. The alternative approach has to deal with the problems of obtaining reliable forecasts of future dividends (see Cornell (1999), Claus and Thomas (2000) and Vivian (2007). (These issues need to be considered in more detail.)

The Competition Commission in its assessment of the risk premium in its Heathrow Gatwick inquiry concluded that a reasonable range would be in the range 2.5 to 4.5 per cent, as reported by SEMC. Their analysis also indicates quite clearly some of the problems in deriving such a range of values and the high level of uncertainty embodied in the estimates. One of the reasons for the relatively high risk premium recorded on an historical basis was the upward adjustment of equity prices over recent decades as investors' perception of risk was reduced and expectations of growth enhanced. The increase in equity prices implied that at these prices the expected return in the future would be considerably lower. But the interpretation of the evidence is subject to considerable controversy. With market conditions now quite different the estimates of the risk premium is likely to be somewhat higher. The assessments of the risks of equity have increased and it is quite possible that the premium required for accepting the risk has also increased.

5. Asset Beta

The derivation of reliable estimates of betas to be employed in setting a company's cost of capital pose a number of problems. It is widely recognised that equity betas estimated for individual companies are highly unreliable, their values depending on the interval of time (days, weeks, or months) used in the process as well as the period of time over which the estimation is undertaken. The estimated equity betas for most companies are not statistically different from one, the value of the average beta. One possible way of dealing with the latter problem is to derive betas on an industry basis. Unfortunately, for most industries the number of companies that might be considered are relatively small, and those with stock exchange listings, necessary to generate the required returns data, are fewer still in number. Moreover, the companies that might be considered are engaged in number of activities in addition to the regulated activities for which the betas need to be derived, as are the generating companies in the All Ireland Market. But despite the difficulties equity betas can in principle be estimated whereas it is not possible to directly estimate asset betas.

SEMC points out that it does not consider asset beta to vary across countries, but that the equity beta does because of differences in gearing and tax rates. Evidence is cited to suggest that asset betas for electricity generation vary on an international basis from 0.50 to 0.80, but there is no reference to the relevant evidence, making it difficult to assess. The Consultative Paper goes on to propose an asset beta of 0.60, in the lower half of the range, without providing a rationale for the judgment. Is the Irish market less sensitive than other markets to fluctuations in the global equity market?

The relevant beta in this context is not the beta for the generating sector – the risks are more specific and relate primarily to fluctuations in the cost of the plant. The cost of the plant will not be related to the local demand for generating capacity but developments in the world market. It is likely that the demand for generating capacity in countries such as China and India will continue to exercise a major influence on the determination of the capacity payment for some years to come. In recent years the cost has been highly volatile and it is likely to continue to be so in the foreseeable future. There are other sources of risk stemming from the nature of the regulatory framework. Firstly, if supply were to increase rapidly in Ireland the limit imposed on the total capacity payments would come into play and dilute the payments based on costs that suppliers have incurred. Secondly, it is quite possible that the regulatory rules will be changed over the next fifteen years, particularly if the market for Ireland is integrated with that for the UK as a whole. Given all of these factors it is unlikely that the appropriate asset beta will be equivalent to that of the generating business as a whole on an international basis.

The specification of the link between the asset and equity beta employed in that analysis appears to overstate the tax advantage of employing debt. The link is based on the Modigliani and Miller (1963) model with corporate taxes and this assumes that once financing arrangements are in place for a business they will be maintained indefinitely into the future. Analysis that is developed on the basis of a company maintaining its asset base over time is not applicable to a project, such as the provision of an increment of generating capacity. The perpetuity assumption is not appropriate in the context of a plant that is expected to be available for a fifteen year period. Indeed a typical financing arrangement will involve a repayment schedule over this time period. This implies that the level of debt will be diminishing each year and as a result the tax advantage will diminish over time as well. One possible approach to this problem is to develop an estimate of the present value of the tax savings for a plant and then identify the annual equivalent payment for use in deriving the yearly capacity payment.

6. Tax rate

No comments.

7. Gearing

The Competition Commission (2007) in the course of their Heathrow and Gatwick inquiry met with three debt rating agencies to discuss the implications of different levels of debt for the credit rating of BAA. The discussion indicated that a ratio of debt to the regulated asset (RAB) of 70 per cent, considered in isolation and given the covenants that BAA was planning to put in place, was consistent with a Baa1/BBB+ rating. But the rating agencies made it clear that the debt to RAB was not the only factor to be taken into account. Qualitative factors and other ratios, particularly the interest cover also had to be considered. On the basis of this evidence the Competition Commission concluded that the cost of capital should be based on an assumed debt to RAB ratio of 60 per cent.

The experience of companies involved in the provision of generating capacity also suggests that the ratio of debt to the asset base is only one of the factors that lenders take into account when assessing the ability to borrow to fund investments in generation capacity. Lenders place considerable emphasis on the ratio of cash flows to debt service requirements. EBITDA is typically expected to be at least 1.50 times the debt service payments, made up of interest plus repayments, for each year of a loan, with the average value of the ratio over the lifetime of loan being in excess of 1.60. These requirements are not consistent with a debt to equity ratio of 7 to 3.