Wilson Cook & Co
Engineering and Management Consultants
Advisers and Valuers

Reply to: Auckland Office
Our ref: 0902
Email: jeffrey.wilson@wilsoncook.co.nz

31 March, 2009

Mr Mike Buckley
General Manager,
Network Regulation North Branch
The Australian Energy Regulator
Marcus Clarke Street
CANBERRA ACT 2601

Dear Mr Buckley,

RE: REVIEW OF PROPOSED EXPENDITURE OF ACT & NSW ELECTRICITY DNSPS: ENERGYAUSTRALIA'S SUBMISSIONS OF JANUARY AND FEBRUARY 2009

In response to your instructions, we have reviewed various matters relating to EnergyAustralia's submissions to the AER of January and February 2009 in relation to its forecast capital and operating expenditure in the next regulatory period, FY 2010 to FY 2014, and submit our report.

1 Credentials

The review has been carried out for and on behalf of Wilson Cook & Co Limited (Wilson Cook & Co) by Messrs Jeffrey Wilson, Derek Walker, Pat Hyland and Bernard Ivory, all of Wilson Cook & Co.

Jeffrey Wilson

Qualified in engineering and commerce (ME BCom CEng FIET FIPENZ MIEEE IntPEng), Mr Wilson has over 38 years of professional experience in engineering and management consulting and advisory work in the electricity supply industry including in corporate development, management training, power system planning, the economic and financial evaluation of projects, asset and business valuations, expenditure assessments and the management of major multi-disciplinary projects in the power sector. He is an adviser in New Zealand to electricity and gas utilities on valuation and regulatory matters. He is an adviser in Australia to regulatory bodies in New South Wales, Victoria, Tasmania, Western Australia and federally (the Australian Energy Regulator) in relation to expenditure projections and fixed asset valuations for price determinations.

He has been an adviser to the Independent Pricing and Regulatory Tribunal of NSW (IPART) since 1997 on various matters including expenditure reviews, prudential issues, public lighting tariffs, the economic and financial modelling of isolated combined-heat-and-power schemes and other specialised tasks. Prior to that, from 1993 to around 1995, he was retained by the then electricity utilities in NSW (including all of EnergyAustralia's predecessor businesses) on fixed asset valuation matters. He is thus familiar with the networks and circumstances of EnergyAustralia and its predecessors – Sydney Electricity, Orion Energy, Prospect Electricity and Illawarra Electricity (as well as TransGrid).

Internationally, he was responsible from 1984 to 2003, as a project director, team leader, power engineer or economist, for power planning and corporate and sector restructuring projects in southeast and south Asia, Portugal, Tanzania and Russia. He has presented expert evidence in the High Court in New Zealand on various matters since around 1976. He is a consultant to the World Bank and Asian Development Bank on project formulation, sector policy and project expenditure matters and his experience includes two years on the staff of the Asian Development Bank.

He is the author of 32 papers on power sector matters and has advised more than thirty electricity and gas transmission and distribution businesses in New Zealand and internationally over the last twenty-five years.

He has corporate governance experience, including chairmanship, since 1988, in electricity utilities, state-owned entities (Industrial Research Ltd), private companies, trust-owned companies and other bodies.

Derek Walker

Qualified in electrical engineering and business studies (BE Hons BBS MIPENZ), Mr Walker has 27 years' experience in management and senior engineering roles in the electricity distribution industry, leading to a thorough understanding of, and practical experience in, all aspects of the industry including generation, wholesale market, retail, distribution and utilisation. He has been responsible for the development and utilisation of costing and pricing models for network and energy retail businesses. He has knowledge and experience in planning, designing, maintaining and operating urban and rural electricity distribution networks. He has considerable experience in negotiating and implementing major business transactions including mergers, acquisitions and sales and a high-level understanding and practical application of all business management disciplines including strategic and business planning, performance management, finance, accounting, treasury, legal, risk management, engineering, marketing and human resources. He has a thorough knowledge and practical experience of governance responsibilities for both commercial and not-for-profit organisations.

He has worked with Mr Wilson since 2004 on expenditure reviews in NSW, the ACT, Victoria, Western Australia and Tasmania and is thus familiar with the Australian electricity industry and with the DNSPs in NSW in particular.

Pat Hyland

Qualified in electrical engineering (BE Hons ME), Mr Hyland has 27 years of professional experience in power engineering and in project management. His experience was initially in generating plant and transmission networks, then in distribution. He has experience in 'due diligence' investigations, numerous project and business assessments, risk assessments and reviews. He has experience in the preparation and review of asset management plans.

He has specialised in the assessment of network service delivery and the prediction of asset lives and in analytical work and the assessment of risk.

He is an adviser to several of New Zealand's largest generation and network businesses, an adviser to network businesses in Australia (but not in NSW), the author of 14 published papers in these fields and the winner of an industry award for a project in automation and control (the Association of Consulting Engineers of New Zealand's Silver Award of Merit, 1992).

Bernard Ivory

Qualified in commerce (BCom in accountancy and economics) and in the professional examinations of The Institute of Chartered Accountants of NZ and The Chartered Institute of Corporate Management (NZ), Mr Ivory has more than 40 years of professional experience in financial and economic analysis and management consulting with an emphasis during the last 30 years on the electricity supply industry. He is experienced in the preparation and assessment of financial models of companies and projects. He is experienced in corporatisation studies, management improvement programmes, sector restructuring, tariff reviews, the review of organisational issues and reforms, project assessments and the review of financial performance of utilities. His experience in these fields includes advice to utilities in Bangladesh, Bahrain, Bhutan, Cambodia, East Timor, Fiji, Indonesia, India, Kiribati, Laos, the Maldives, Malaysia, Mongolia, Nauru, New Zealand, Pakistan, the Philippines, Singapore, Sri Lanka, Solomon Islands, Thailand, Tonga, Tuvalu, Vanuatu and Vietnam and to the World Bank and Asian Development Bank in respect of them.

He has worked with Mr Wilson frequently since 1984 on power utility performance improvement projects and, since 2001, on expenditure reviews in NSW, Western Australia and Tasmania and is thus familiar with the Australian electricity industry and with the DNSPs in NSW in particular.

2 Scope of Review

The requested scope of the review in respect of EnergyAustralia was to:

(a) review and provide technical advice on EnergyAustralia's submissions of January 2009 comprising a revised regulatory proposal and supporting documents and a further revision and supporting documents submitted in February 2009;

(b) provide technical advice on specific issues raised in EnergyAustralia's submissions;

(c) consider any new information provided by EnergyAustralia and advise of any revisions needed in the recommendations made by us in our Final Report to the AER of 21 November 2008 (Final Report);

(d) provide details of any proposed revisions to EnergyAustralia's levels of opex and capex as a result of any changes in the recommendations;

(e) identify any new information that has led to the revision of our previous recommendations (or, if no revisions are proposed, why EnergyAustralia's submissions and new information do not lead to revised recommendations); and

(f) have regard to stakeholder submissions (which were expected by 16 February 2009) raised in relation to the issues to be reviewed.

The matters referred to in (b) above related, essentially, to EnergyAustralia's claims in sections 9.2 (step changes or, more particularly, the justification of step changes and "top-down" benchmarking), 9.3 (maintenance costs or, more particularly, the assessment of capex-opex trade-off modelling) and section 9.4 (the workload escalator used for costs in the 'Asset Management' and 'Major Projects' branches) of its January 2009 submission in relation to its opex.

The principal supporting documents referred to us were those prepared by Huegin Consulting (Huegin) and SKM, although we found that reports by Concept Economics, NERA and PricewaterhouseCoopers (PwC) were relevant to our task as well.

Other Matters

We were also asked to consider certain matters relating to EnergyAustralia's capex – more particularly: (a) the impact of EnergyAustralia's revised peak demand forecast on its capex requirements (raised in sections 3.1 and 3.2 of its January 2009 submission); (b) the prudence and efficiency of the costs associated with its 'black spot' reliability programme (raised in section 3.5 of its January 2009 submission) including whether, in our opinion, the programme is required to meet the capital expenditure objectives set out in clause 6.5.7(a) of the Rules; and (c) the prudence and efficiency of zone substation expenditure (raised in section 3.6 of EnergyAustralia's January 2009 submission) including SKM's review in attachment 3M to that submission. However, we were not able to consider these matters adequately in the time available and thus did not attempt to do so. [1] In addition, we noted that the second appeared to entail an interpretation of the Rules and the third did not relate to a recommendation made in our Final Report.

Finally, our terms of reference required us to consult with the DNSPs as necessary and to seek any additional information needed. However, there was not sufficient time available to enter into a dialogue, in addition to which we considered it reasonable to rely on EnergyAustralia's submissions as presented to the AER.

We were to present our draft report to the AER by 27 February 2009 and we consulted the AER before the work began to clarify what it was practical to achieve in the limited time available for the review. The scope of this report reflects the conclusions so reached.

3 Matters Not Reported On

The review was limited to the context of our instructions – namely, to report on matters affecting or potentially affecting the adjustments to EnergyAustralia's expenditure that we recommended in volumes 1 and 2 of our Final Report.

4 Methodology and Work Carried Out

EnergyAustralia has argued in its submissions of January and February 2009 to the AER that its opex should not have been reduced in the AER's draft determination. It claims amongst other things that (a) our "top-down" benchmarking contained methodological errors, (b) our criteria for accepting or rejecting step changes were not consistent with the Rules, (c) our "bottom-up" analysis did not reflect a proper detailed review of the cost items concerned, (d) we had made simplifying assumptions in our step change criteria (*viz.* that controllable step changes would be offset by efficiencies) to avoid a detailed consideration of the actual items, (e) our criticism of EnergyAustralia's capex-opex trade-off relationship in connection with maintenance costs was incorrect and (f) our assessment of workload escalation for the Asset Management and Major Projects branches of the business was not appropriate. [2]

EnergyAustralia has provided new information in and with its submissions, which it claims supports its arguments and our review has entailed an assessment of the submissions and supporting documents, as far as they relate to the findings expressed in our Final Report. Specifically, our review is restricted to those parts of the submissions and supporting documents that relate to areas where we found adversely in our Final Report – *viz.* consideration of EnergyAustralia's opex step changes, the capex-opex trade-off and its impact on projected increases in maintenance costs, and workload escalation in the Asset Management and Major Project branches.

Scope of Re-Examination

The documents received were comprehensive and caused us to re-examine seven matters:

(a) our opinion that EnergyAustralia's opex in FY 2007 should be accepted as an efficient level of base-year expenditure upon which to base future levels of opex;

(b) our opinion that EnergyAustralia's forecast significant increases in opex from that in FY 2007 to FY 2014 – which, we observed, would occur at a significantly greater rate than was suggested by the combination of growth and inflation or by a comparison with its peers in the ACT and NSW – raised questions about how its projected levels of opex in the period FY 2009 to FY 2014 could be considered to remain efficient;

---

[1] This is not to say that *prima facie* a reduction in capex should not be made in the present economic and financial circumstances; only that we are not able to review the changes to the depth required to present anything other than a superficial observation as demand forecasts go to the heart of the capex forecasting process.

[2] Taken from EnergyAustralia's January 2009 submission, sections 9.2.2, 9.3 and 9.4.

(c) our opinion that the majority of the "step changes" in opex forecast by EnergyAustralia were not sufficiently justified to be accepted as efficient for the purpose of our review;

(d) our opinion that EnergyAustralia's capex-opex trade-off assumptions were not correct and likely to overstate efficient costs;

(e) our opinion that EnergyAustralia's workload escalator for costs in the Asset Management and Major Projects branches of the business were not appropriate;

(f) our consequential recommendation to the AER that EnergyAustralia's opex should be reduced, as set out in a "bottom-up" calculation in our Final Report; and

(g) our assessment, based on a "top-down" expenditure benchmarking analysis against a peer group of predominantly urban distributors, that the reduced level of opex so recommended was appropriate.

Benchmarking Methodology

To expunge any methodological errors, we reassessed our benchmarking analysis as far as it affected EnergyAustralia by setting aside any reliance on Ofgem's benchmarking formula (whether using the weights cited by Saha [3] and used by us in our Final Report or those presently or recently under discussion by Ofgem and interested parties in the UK [4]) and any other pre-determined position, e.g. in relation to intercepts with the origin in the benchmarking graphs. [5] Starting afresh, we took the set of recent data available for our selected group of Australian urban utilities and made corrections to it. [6]

Then, using solely that data, we carried out a multiple regression analysis to determine the correlations that exist between opex and some or all of the various parameters (customer numbers, line length, energy throughput, maximum demand, etc).

We analysed linear and logarithmic relationships to determine the choice of parameters and relationship that best predicted opex.

Predominantly rural entities were excluded, based on the findings of the multiple regression analysis. [7]

The results were most revealing (and we are indebted to EnergyAustralia and its advisers for their contribution to the benchmarking debate generally) and led us to propose, in this report, a completely different formula as the best predictor of opex. Confidence limits were calculated and added to the graphs to add to the robustness of the analysis. No pre-supposition was made in respect of any assumptions such as zero intercepts or otherwise.

To repeat the point: the revised analysis presented in this review is based solely on the analysis of Australian businesses and a carefully selected and comparable peer group of predominantly urban utilities.

---

3 *"Electricity distribution business operational expenditure review"*, 4 April 2008, Saha International, Attachment 6.2 to EnergyAustralia's June 2008 submission.

4 See, for example, the supplementary appendices to Ofgem's *"Electricity distribution price control review initial consultation document"*, 28 March 2008.

5 The revisions would not have caused us to change our recommendations in respect of any of the other DNSPs whose expenditure was examined in our Final Report.

6 The data is as used in our Final Report with the exception of a correction made in ETSA's opex (to which we are indebted to Mrs Margaret Beardow of Benchmark Economics for pointing out the error) and a minor modification in EnergyAustralia's opex (comprising the removal of $10 m of storm-related costs in the base year). For the avoidance of doubt, the correction in ETSA's data does not affect the analysis of EnergyAustralia's position, as ETSA has been categorised as a predominantly rural utility and EnergyAustralia as predominantly urban. Rural entities have been excluded from the analysis that concerns EnergyAustralia's expenditure, as stated above.

7 They were treated separately in our Final Report as well.

We present our analysis later in this review but would like to note an important conclusion before going on to the next matter. Whilst the benchmarking methodology is now robust – as it should be – the results do not differ materially from the simpler method (which we have now abandoned) used in the Final Report and thus the conclusions drawn from the analysis remain unchanged.

For the avoidance of doubt, we note that the conclusions drawn from the benchmarking in our Final Report were limited to *tests* of reasonableness. Any suggestion that we used benchmarking as a *determinant* of reasonable levels of efficient opex for EnergyAustralia is incorrect.

Benchmarking a Practical Tool to Assess Cost Structure as a Whole

We had noted in 2008 that consideration of inflationary provisions and step changes alone would not be sufficient to determine the efficiency of EnergyAustralia's opex. We had noted that it was necessary, therefore, to form a view on the efficiency of EnergyAustralia's base-year opex by a comprehensive review of EnergyAustralia's cost structure as a whole, by benchmarking or by another method.

We noted that a comprehensive review of EnergyAustralia's cost structure as a whole was beyond the scope and time available for our review, quite apart from the difficulty that would be encountered in attempting to carry it out, and it was for that reason that we considered it necessary to benchmark EnergyAustralia's (and the other DNSPs') base-year (FY 2007) opex to form a view on its efficiency in comparison with that of industry peers.

In that context, it could be said that benchmarking of opex is an essential practical ingredient in opex reviews of this type.

We noted that our conclusions in respect of the efficiency of EnergyAustralia's base-year opex had been stated in our Final Report but we decided it was appropriate to reconsider those conclusions in this present review in light of the revisions made to our benchmarking analysis.

Movements in EnergyAustralia's Opex from FY 2007 to FY 2014

We noted in our Final Report that EnergyAustralia's opex was projected to increase significantly – and at a far greater rate than its peers in the ACT and NSW – between FY 2007 and FY 2014 and that an increase of the size projected made it difficult for us to conclude that EnergyAustralia's opex, if efficient in the base year, could be said to remain so over the period.

We considered (but did not say so in our Final Report) that for EnergyAustralia's opex to still be considered efficient at the end of the next period (FY 2014) notwithstanding the large increases foreseen, it would be necessary for EnergyAustralia to demonstrate that it was starting from a low base, below the industry norm, and that a significant increase in its opex ought to be agreed to. Alternatively, it would need to be demonstrated that the increased levels of expenditure were required to support increased service levels in the period but we found no evidence that increased service levels were proposed. [8]

We re-examined the information received in this regard and report our findings later in this review.

Consideration of Step Changes

Consideration of Benefits

In relation to EnergyAustralia's proposed step changes in opex, we had stated, in our Final Report, that in a competitive market, "businesses do not normally add to their own costs unless they are satisfied that there is a benefit to customers in terms of the product delivered or to the business in terms of efficiency. Regulation presumably ought to incentivise natural monopolies in a similar way. Second, businesses are dynamic, with variations occurring from year to year. Such variations ought not to form the basis of a claim for a step change, as the effect of that

[8] We identified an overdue need for capex but not for opex, and recommended accordingly.

would be to allow costs to be passed on readily in contravention of the efficiency objective implicit in the regulatory framework." [9]

We had expressed the concern that "a methodology such as that used by EnergyAustralia that starts with a base year and then applies cost escalators, workload escalators and step changes (which apart from some adjustments for abnormal items in the base year are almost all additional costs) without any explicit consideration of business efficiency improvements or potential cost savings is likely to lead to a forecast of future costs that is above an efficient level". We considered that this remained a valid principle to guide our review, although we recognised that to be consistent with the preceding quotation, this quotation should also have referred to "benefits to customers" as well as to "business efficiency improvements or potential cost savings".

We had considered that for acceptance as a step change, "a cost ought to relate to a fundamental change in the business environment arising from outside factors or be offset by cost efficiencies in other areas" and we considered that for consistency with the preceding quotations, this quotation should also have referred to "benefits to customers" as well as to "cost efficiencies in other areas".

Evidence of Specific Improvements in Efficiency, Productivity or Customer Benefits

We had noted on p. 51 of our Final Report, "We could not find any indication that EnergyAustralia has allowed for specific improvements in organisational efficiency or productivity in its proposal. It advised us that productivity changes had been allowed at a "sector" level in the forecast of future labour costs". However, we consider that the large investment proposed in IT systems and property should lead to improvements in business efficiency and reductions in opex".

To verify this statement, we reviewed the earlier material given to us by EnergyAustralia and the new information subsequently received to see if our earlier assessment was correct in this respect or should be revised.

In doing so, in cases where the benefits of the expenditure were said to be in the form of improved customer service, we looked for evidence that improved service levels were forecast because of the expenditure. As discussed later in this review, we did not find any such evidence.

Connection between IT Capex and Opex

We recognised that in our Final Report, the discussion in section 9 on step changes had not referred back to the earlier discussion in section 8 of EnergyAustralia's non-system capex. Benefits, efficiencies and productivity gains are discussed in several places in that section and, in concluding our assessment of IT capex in that section, we noted that "little emphasis had been given to potential efficiency gains that the [integrated asset management] system might achieve" and "we consider that whilst this can be difficult to measure or predict, it is something that should be considered to make sure that investment in systems does lead to efficiency in the business" and, later: "we found nothing unusual or excessive in the proposed [IT capex] programme but noted that improvements could be made in identifying the business efficiency improvements to be expected from the investments". [10]

We considered whether the assessment presented in section 8 of our Final Report had been a balanced view of the related capex issues. We concluded that it had and did not examine them further.

We noted that EnergyAustralia had recognised the connection that existed in our minds between the two (although the connection was not stated in our Final Report) when, on p. 90 of its January 2009 submission, it states in relation to large-scale investments in IT and reductions in opex that "perhaps a better understanding of Wilson Cook [&Co]'s concerns lie in its assessment of IT capital expenditure when it states: *After considering these factors, we concluded that the*

---

[9] Final Report, p. 51.

[10] Ibid, p. 44.

expenditure on IT systems was reasonable without adjustment but noted that such investments should result in improved business efficiencies and operational cost savings".

Method of Consideration of Step Changes

We recognised that our Final Report had not included a detailed evaluation of individual step changes proposed by EnergyAustralia, other than in respect of whether they met the criteria we set down.

We considered EnergyAustralia's claim that our criteria for accepting or rejecting step changes were not consistent with the Rules but we offer no view in response to that claim, as we have not attempted to interpret the Rules and we did not then nor do we now consider it our place to do so.

We considered EnergyAustralia's claim that we ought to have reviewed each change individually in detail (or words to that effect) instead of considering whether each met the test of a valid step change as set out in our Final Report *viz.* that "a cost ought to relate to a fundamental change in the business environment arising from outside factors or be offset by cost efficiencies in other areas". We recognised that the statement quoted had not referred to the earlier discussion in our Final Report recognising "benefits to customers" (see above).

Consideration of Efficiency an Essential Test

We considered whether Huegin's proposed method of assessment of step changes ought to be adopted in place of the method used in our Final Report. [11] However, we found that Huegin did not appear to have considered the efficiency or cost effectiveness of the step changes in expenditure, only their claimed necessity or unavoidable nature. Efficiency, however – or, where benefits are said to be in the form of improved customer service, then a statement of the improved service levels resulting from the expenditure – was a necessary condition for us to endorse the expenditure for the AER's purposes.

Quantification of Benefits in Amount and Time

We noted that neither EnergyAustralia nor Huegin had, as far as we are able to tell, quantified the claimed benefits in relation to the step changes in terms of amount or time of occurrence and we considered that lack of quantification to be a material weakness in its argument that the step changes in expenditure were justifiable.

Consideration of Risk

We considered whether risk should be added to the factors used to determine the acceptability of a step change in opex. However, risk cannot be considered unless cost, benefits and potential adverse impacts are quantified. Quantification in this context would need to include identification of the probability and consequences of losses, consideration of alternative risk mitigation measures and an assessment that showed that expenditure on mitigation provides a benefit based on the offsetting reduction in probability and consequence. Little or no quantification of benefits had been attempted by EnergyAustralia and so no quantification of risk was possible.

Consideration of Timing Issues

We noted that EnergyAustralia had gone on to claim that our contention that large-scale investments in IT lead to significant cost savings in opex is based on an incorrect understanding of the time period over which efficiencies are realised and how these efficiencies are accounted for. We therefore re-examined the question of timing of benefits, noting that any generalised statement that benefits would normally be delayed – the implication being that they would normally be delayed significantly – could be misleading as only some benefits would be delayed: others could be expected to occur more proximately to the corresponding expenditure. As investments were being made prior to or near the beginning of the next period, benefits in terms of efficiencies should start to flow in the next period.

---

[11] Huegin uses a modification of the "ISSR" method developed by Booz Allen Hamilton in the 1980s to achieve cost reductions in US defence contracts: see p. 16.

Standard of Opex Documentation Generally

Our general view of EnergyAustralia's opex documentation, formed during the 2008 review, was that it was not as strong as its capex documentation. This was reflected in the levels to which were able to undertake our assessments. Especially in IT, we considered the level of supporting documentation relating to opex to be minimal. For example, we found in the case of the IT supporting information [12] that there was a considerable amount of detail on the capex components but little detail on how opex had been derived. The supporting documentation for other opex cost streams generally appeared to be focussed on how base-year costs would increase through workload escalation and cost escalation and how they would change with the addition of new items or, in a small number of instances, the discontinuation of activities but without a broader assessment on the efficiency and effectiveness of existing activities and how the investments in new processes and systems would reduce costs.

We re-examined the information received in this regard and report our findings later in this review.

Opex Model a Calculating Tool

There may be a degree of implication in EnergyAustralia's submissions or those of some of its advisers that sophisticated opex modelling guarantees efficiency. We do not dispute that EnergyAustralia's opex modelling was comprehensive but the model *per se* is a calculating tool and not a guarantee of efficiency. Instead, like all such models, its output is determined by the assumptions made. It is those assumptions that we reviewed and saw fit to challenge in certain cases.

We re-examined the supporting documentation relating to the model in this regard and report our findings later in this review.

New Information and Re-consideration of Previous Recommendations

We considered the new information submitted by EnergyAustralia in light of the points set out in the sections above. We reviewed our categorisation of step changes and considered the step change expenditures individually to the extent possible within the limits of the information supplied. We noted whether cost savings, efficiencies and benefits, quantitative or not, had been identified and, if quantifiable, whether quantitative information had been provided in respect of amount and timing. We noted whether efficiency of expenditure had been considered transparently in addition to necessity or lack of avoidability.

In particular, we sought to determine:

(a) whether a demonstrated need for expenditure in the first place was identified in EnergyAustralia's submissions and supporting documentation;

(b) whether benefits, quantifiable or not, were identified in the new documentation or had been identified in the original documentation;

(c) whether, if quantifiable, the benefits were so quantified in terms of amount and time of occurrence or at least likely time of occurrence;

(d) whether, if quantified, evidence was presented sufficient to demonstrate that the solutions chosen were based on comparative studies and were demonstrated to be the least-cost options for meeting the need;

(e) whether, if the identified benefits had been said to be in the form of improvements in service levels, reliability or the like, they were reflected in projected improvements in the corresponding service targets;

(f) whether a time lag in the appearance of benefits ought to be recognised in particular cases; and if so too what extent; and

---

[12] Supporting document: *"Non-System IT: Detailed Proposal"*.

(g) whether there were any other relevant factors to be considered.

Matters Not Addressed

For reasons of clarity, we did not attempt to address all the claims made in the supporting documents that accompanied EnergyAustralia's submissions but have concentrated on the arguments that EnergyAustralia itself has identified as crucial or of most concern.

We present our analysis later in the review.

Capex-Opex Trade-Off in Relation to Escalation of Maintenance Costs

EnergyAustralia has claimed in its January 2009 submission that our objection to its capex-opex trade-off relationship in connection with the escalation of its maintenance costs was incorrect. The trade-off was a matter on which EnergyAustralia presented a report from SKM at the time of its original submission in 2008. We raised several questions at that time about the calculations:

- whether the costs of maintaining new assets are comparable with those of maintaining old ones (this affects the first point on the graph and the relationship between the points);
- whether the first point on the graph (the cost of maintaining a new asset), which had been established by assuming that maintenance costs are a stated percentage of the replacement cost of a new asset but using a percentage developed in 2002) was still relevant, given the significant changes in replacement costs that have occurred over the last five years;
- whether the present maintenance costs, which determine the second point of the graph, are efficient (and in that regard, we noted that EnergyAustralia was catching up on a backlog of deferred maintenance in FY 2006, raising the question of whether that ought to be adjusted for); and
- why the curve should be exponential.

We cited evidence available from the New Zealand electricity supply industry that suggested that direct costs might not increase exponentially with the average age of the network components, although they may be related to age in another way.

In respect of the first question, after enquiry from us in 2008, EnergyAustralia undertook further analysis and concluded that changes since 2002 would reduce the projected expenditure by $19.4 m or 1.6% over the next period. We were also advised that it had discovered errors in its asset age profile information, resulting in the need for a further adjustment of $4.1 m. These adjustments were noted in our "bottom-up" assessment. However, we retained the concern that further correction was required and, in our Final Report, concluded that there was doubt about the robustness of applying EnergyAustralia's analysis to derive a workload escalator for maintenance.

EnergyAustralia submitted a further report from SKM with its January 2009 submission and we have examined it and comments from Huegin on the same matter to see whether our view of the capex-opex trade-off relationship was correct or whether the maintenance workload escalation calculation recommended by us should be revised.

We noted that the relationship was pertinent to our "bottom-up" analysis of EnergyAustralia's opex. [13]

Our findings are presented later in this review.

---

[13] The adjustment recommended in our Final Report appeared in Table 9.13 in the line "Maintenance escalation".

Workload Escalator for Asset Management and Major Projects Branches

EnergyAustralia has claimed in its January 2009 submission that our assessment of workload escalation for the Asset Management and Major Projects branches of the business was not appropriate.

The point that we had objected to in EnergyAustralia's original proposal was the use of real system capex as a driver of workload increases in these two business units. We had noted that as presented by EnergyAustralia, large increases in capex were said to drive similarly large increases in the cost of these support services that in our opinion might not be appropriate. We considered that if the capex programme was driving those costs, the costs should be capitalised.

Irrespective of that, we did not consider in our Final Report that the relationship was as direct as assumed. In addition, we noted that project value *per se* was not necessarily an appropriate measure of the resources required to oversee capital projects. We considered that that was confirmed by information on staff increases that did not show growth of the same magnitude as the capex programme. We considered that the increases were overstated and, accordingly, we calculated an adjustment by applying an escalator based on forecast changes in the network division staff instead of real system capex. [14]

We re-examine those findings later in this report.

5 Interpretation of Our Reports

Limitation

Before continuing, and in relation to the interpretation of our reports, we emphasise that statements made in our reports are limited to the particular matters stated. No implied extension of our text, implied conclusion or opinion, or quotation taken in isolation from our text as a whole should be attributed to us or be given any weight by the AER or any other authority considering the findings of our reports.

No Interpretation of Law or Rules Intended

No statement made in our reports should be taken as an interpretation of the applicable Law or the Rules, as none is intended.

6 Interpretation of Huegin's Report

Caution appears to be needed when reading the Huegin report, as a number of statements in the report are open to differing interpretations and some appear to be incorrect. Examples are given below and others could be cited.

Huegin's statement on p. 11 that "close inspection of the step changes reveals that efficiencies and cost savings have been taken into account [by EnergyAustralia] wherever those cost savings could be identified" does not appear to have been tested by Huegin, so there is no assurance that all the cost savings that could have been be identified were identified. In addition, the statement does not align with our review of EnergyAustralia's opex documentation, from which we found little or no quantification of efficiencies or benefits in terms of quantum or time.

Huegin's following statement (ibid) that "It is our opinion that this approach to modelling cost efficiencies is a more robust and reliable method than applying broad organisation wide productivity factors" suggests a lack of understanding on Huegin's part of EnergyAustralia's opex model, which does not automate efficiencies *per se* but is only a calculating tool reliant on the assumptions made in its input data. The text in the report appears to us to suggest the unsupported assumption that efficiency is inherent in what EnergyAustralia does whereas, from our standpoint, we considered that a suitable level of proof was required.

---

[14] Final Report, p. 58.

Various other statements in the report are unsupported by evidence. For example, Huegin's claim on p. 19 that "EnergyAustralia has proposed step changes in the cost of particular activities that it considered were necessary to meet its operating expenditure objectives …[and that they may have been] summarily dismissed by Wilson Cook [& Co] despite the volume of detail of supporting information in the associated business cases" may mislead as it makes no mention of the adequacy of the supporting information. It also assumes that we were given all the material that Huegin received. Neither point is established; and our assessment of the material that we did receive is markedly different from Huegin's.

Huegin's statement on p. 24 that "CSV is used [by Wilson Cook & Co] as a determinant of cost efficiency" implies that CSV determined our findings, whereas such an interpretation would be incorrect. CSV was used by us only in a "top-down" analysis as a *check* of reasonableness: the quantum of our adjustment was determined from a different ("bottom-up") analysis. Huegin's statement therefore appears to us to be misleading.

In addition, we would like to correct the following points. Huegin's statement on p. 14 of its report that our benchmarking analysis "appears to be overly reliant on comparison with the only other DNSPs to have submitted forecasts out to 2014 – i.e.: the [three] other NSW and ACT DNSPs" is clearly inaccurate, as thirteen utilities were included in the main benchmarking comparison – that of opex as a whole – and six utilities were considered in the "urban only" analysis.

Huegin's reference to the differences between rural and urban utilities (ibid) may be misleading, as we provided a separate analysis for each group.

Huegin's general reservations (ibid) may also be misleading in terms of the impression given since, as far as we can tell, Huegin has not taken account of the high correlation observed in our urban-only analysis as stated in our Final Report. (Note: it is only the *urban* analysis that is relevant to the assessment of EnergyAustralia's expenditure.)

Huegin's statement on p. 14 of its report that "[Huegin] considered that the definition of efficiency as proposed by Wilson Cook & Co (that an efficient operator *might undertake less work than is necessary*) could lead to erroneous conclusions of EnergyAustralia's level of efficiency" could create a misleading impression of the substance of our work as no such definition was stated by us and the words referred to are taken out of context. [15]

7 Summary of Conclusions

In summary, having reviewed EnergyAustralia's submissions of January and February 2009 and, where necessary, the original information provided by EnergyAustralia, our opinion is as follows.

(a) Caution appears to be needed when reading the Huegin report, as a number of statements in it are open to different and possibly misleading interpretations – see section 6 above.

(b) A completely revised and robust benchmarking of EnergyAustralia's opex with a carefully selected group of peer utilities in Australia confirms our opinion that EnergyAustralia's adjusted opex in FY 2007 should be accepted as an efficient level of base-year expenditure upon which to base future levels of opex. Further details are given in section 8.1.

(c) Although we agree that EnergyAustralia's adjusted FY 2007 base-year opex may be regarded as efficient, our opinion remains that EnergyAustralia's projections of opex are not and therefore need to be adjusted.

(d) However, the new material received suggests that more of EnergyAustralia's proposed step changes in opex ought to be accepted than we recommended in our Final Report and we have provided a revised recommendation in this regard in section 8.11 of this review, accepting the majority of items other than IT-related step changes.

---

15 Huegin later dismissed its own point as "academic".

(e) Notwithstanding claims to the contrary, we remain of the opinion that EnergyAustralia has not identified the benefits attributable to all of its proposed step changes numerically nor shown where it has allowed for them in its estimates of opex for the period FY 2010 to FY 2014 and so we do not recommend acceptance of the remaining step changes. Further details are given in section 8.38.2 to 8.6 of this review.

(f) The findings summarised above take into account our assessment of new information in respect of EnergyAustralia's capex-opex trade-off assumptions (see sections 8.7 and 8.8) and the workload escalator for costs in the Asset Management and Major Projects branches of the business (see sections 8.9 and 8.10). The points are technical and reference should be made to the later sections of this report for our assessment.

The reasons for these conclusions are explained in the following text, which is arranged under headings identifying the disputed factors that are material to our conclusions.

For clarity, we have not commented on any matters raised by EnergyAustralia that were immaterial to our conclusion.

Opinions Expressed in Final Report

For the avoidance of doubt, the opinions expressed in our Final Report as far as they concern EnergyAustralia's actual or proposed expenditure remain unchanged, except where specifically modified by this letter.

8 Supporting Details

Supporting details relating to our conclusions are presented in the sub-sections below but this section of the review should be read in conjunction with the background information set out in section 4 above.

8.1 Regression Analysis and Opex Benchmarking

Revised Regression Analysis

Whilst not necessarily agreeing with Huegin's claims on other matters, the points raised by Huegin on our use of the composite size variable (CSV) prompted us to re-examine its use. We summarised the claims made by Huegin in relation to this matter as follows:

- the applicability of using an explaining variable derived in a jurisdiction outside Australia was questioned;
- a claimed lack of homogeneity in the DNSPs used was alleged;
- a high degree of correlation between the variables making up the CSV was alleged;
- the constrained regression, forcing the zero point, was questioned;
- it was claimed that an unconstrained regression showing a negative offset implied that the regression model was inadequate in the circumstances;
- the statistical relevance of the analysis was questioned; and
- it was claimed that there might be inaccuracy in the estimation of the projected line lengths used in the modelling.

To address these issues, and as already outlined in this review, we decided to undertake a completely fresh analysis that placed no reliance on any pre-determined position or on Ofgem's work but was reliant solely on Australian data for a carefully selected group of predominantly urban utilities.

We undertook a multiple regression analysis to derive a regression based solely on the relationships observed within the data. The software used was "R" version 2.4.0 and the variables considered were customer numbers, line length, MW of demand, MWh of energy throughput and network type (urban or rural, based on customer density) and the data set was the same as described in section 3 of volume 1 of our Final Report with corrections as noted above. [16]

Two models were considered to predict opex, a linear combination of the available variables and a linear combination of the log values. [17]

Examination of the relationships between the variables within the data revealed strong correlations between customer numbers, MW and MWh, indicating that combinations of these variables should be avoided.

Significant variance in behaviour between the urban and rural DNSPs indicated that these networks should be considered separately, as was done in our original evaluation. As the analysis is to be applied only in respect of EnergyAustralia, rural DNSPs were not considered further.

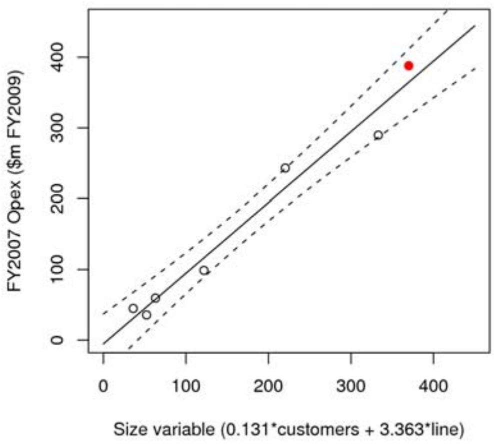
Variables were included or removed from the regression models based on assessment of their significance, the distribution of model residuals, the R-squared statistic and changes in the AIC statistic. [18]

The final selection of the linear model was on customer numbers and line length and the final selection for the log model was on the log of line length.

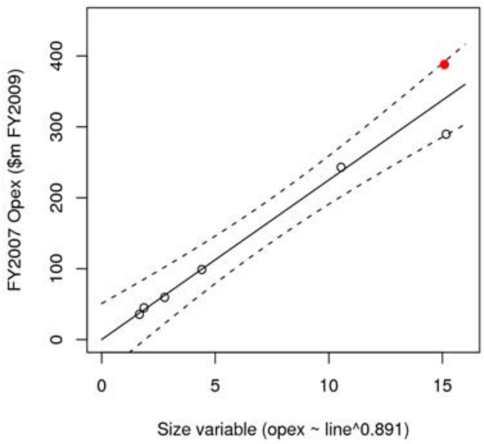
For clarity of comparison, new composite variables were created based on the model formulations and linear regressions applied on the composite variables. [19]

The regression lines, including 95% confidence bounds and with the FY 2007 opex points plotted are presented in the following two figures for the linear and log models respectively. EnergyAustralia's data point is plotted in red.

Regression of Opex on Customers plus Line Length (Linear Model)



Regression of Opex on Line Length ^ 0.89 (Power Model)



Both models show regressions that are highly significant, indicating that the combination of variables used in each case has significant describing power in relation to the DNSPs' opex

16 See footnote 6.

17 A linear combination of the log variables would replicate the original CSV variable that combined other variables raised to determined powers.

18 Akaike Information Criteria (AIC): see Venables & Ripley, *"Modern Applied Statistics with S"*, 4th edition, Springer, 1999.

19 In the case of the linear model, this changes the degrees of freedom. The effect on the model confidence limits using a single composite variable was examined and found to produce a wider (i.e. more conservative) confidence band.

outcomes. This leads to the conclusion that the regression, as formulated, is evidentially applicable as a comparator of base year opex and as an escalator of opex cost in relation to increasing size over time.

Neither model is constrained; both permit an offset term. In the case of the linear model, the offset is approximately minus $5 m. We do not ascribe any significance to that as: (a) a zero-sized network is not attainable and the offset may imply either costs or benefits of scale in a network approaching zero size, and (b) as indicated by the regression confidence bounds, the zero crossing is not statistically significant and so the matter is immaterial in any case.

The two models are similar but we selected and proceeded with the model using a linear combination of customers and line length as: (a) the distribution of residuals is closer to a normal distribution, (b) the adjusted R-squared is slightly greater (0.97 *vs.* 0.95), and (c) the power model exhibits unevenly distributed residuals with increased variance towards the right, which is the main area of interest.

Base Year Opex

Both models show that EnergyAustralia's FY 2007 opex lies within the confidence bounds, supporting our view that its opex in this year – its base year – is comparable with its peers and may be considered efficient for the purpose of our review.

Movement in Opex from FY 2007 to FY 2014 in "Top-Down" Analysis

For the purpose of our "top-down" analysis, we applied the selected regression model as an evidentially applicable escalator to the FY 2007 level to assess the movement in opex through to FY 2014. However, that analysis was not used as a determinant of opex, only as a test of reasonableness.

Used in this manner, the regression gradient projects the efficient expenditure path from the FY 2007 base year in terms of the changes in the network descriptors. That is, it projects the increase in opex that can be expected to occur in the next period due to the increase in size of the network business – before considering step changes or inflation.

8.2 Step Changes and the Huegin Report

EnergyAustralia's Opex Forecasting Methodology

EnergyAustralia's forecast opex for each activity was built starting from the efficient base cost for that activity and then escalated based upon workload escalation factors that were applied only to the variable element of costs to reflect the real growth in the quantity of actual tasks performed; price escalation factors applied to both fixed and variable elements of costs to reflect the expected real increase in the costs of performing the activity; and step impacts to recognise incremental movements in costs which are expected to occur in changes to the efficient base cost of the particular activity. These changes occur when the function of an activity is changed from the base year to the next year, or when base year cost is abnormally high or low and. as such, they do not represent long-term expected cost levels. Step changes can be positive or negative. [20]

EnergyAustralia's Opex Forecasting Model

EnergyAustralia's opex forecasting model allows for the inclusion of efficiency improvements and cost savings in the same manner as cost increases, i.e. as either escalation factors or step changes to specific activities. We noted that EnergyAustralia had not used any broad escalation factors for productivity, instead saying that it had built them into individual step changes. However, on attempting to confirm that efficiency improvements and cost savings were entered in the model, we could find no quantification of such things. We did find a worksheet ("Prod Esc") in the model that allows entry of efficiency improvements but all cells were set to zero.

---

[20] We confirmed that the step changes were generally not escalated by workload but found some instances (at least three) where both step changes and workload escalation were applied.

EnergyAustralia claims there have been some allowed in the step change calculations and Huegin claims to have identified them in its line-by-line assessment of the step changes but no other information has been provided.

Huegin's Findings

Huegin claims a number of findings in its review of EnergyAustralia's opex proposed for the next period. In relation to our work, it claims amongst other things that: (a) our analysis supporting the removal of step changes is based on an invalid definition of a step change in cost; (b) we have assumed that any cost increase should be offset by equivalent and immediate cost savings; and (c) the use of a Composite Scale Variable (CSV) as a comparative determinant of efficient levels of opex is not appropriate.

(The inferred assumption that any cost increase should be offset by equivalent and immediate cost savings is drawn from our not allowing the step changes but we were unable to find any quantification or timing of benefits for any of the proposed expenditures.)

Huegin claims that the application of the step change test appears selective and inconsistent and that little or no evidence of analysis sufficient for the robust application of the proposed test was presented in our Final Report.

It claims that its review of the step changes at an adequate level of detail reveals that many of the step changes would pass our step change validity test.

It presents an alternative method of assessment (see below) that it claims is more robust and that the results of its use indicate that, whilst a number of the step changes rejected by us warrant further investigation prior to approval by the AER, the majority represent the reasonable costs of a prudent operator in EnergyAustralia's circumstances.

(At the same time, on p. 20 of its report, Huegin claims that that our step change criteria should be expanded to recognise expenditure related to the mitigation of risk – a point we have discussed on p. 8 – in essence suggesting the expansion of our criteria despite suggesting their replacement.)

Huegin acknowledges on p. 20 of its report that it is reasonable to expect benefits from particular cost increases incurred by an organisation although it claims that the assumptions of how and when the efficiency gains are made are overly simplified in the AER's determination [and implicitly in our report]. It claims they ignore the facts that: (a) not all expenditure will result in efficiency or productivity gains - there are a number of other benefits that may be realised, e.g. regulatory compliance, risk avoidance and customer service levels; and (b) where cost savings are possible as a result of investment, the effect is not always evident in that particular cost centre and is very rarely immediately realised – but may materialise later and/or in other parts of the business. Huegin claims that EnergyAustralia has proposed step changes in the cost of particular activities that it considered were necessary to meet the operating expenditure objectives of the Rules and claims that the step changes have been summarily dismissed by us, despite the volume and detail of supporting information in the associated business cases.

(We note again our point that none of the improvements capable of financial evaluation was so evaluated as to quantity or timing nor, we infer, offset against the costs.)

Huegin's Alternative Methodology for Assessing Step Changes

Huegin's alternative methodology for assessing step changes – see section 3.3 of its report – is based on a modified version of the ISSR framework developed by Booz Allen Hamilton in the 1980s to facilitate cost reductions on US defence contracts. [21]

---

[21] See http://www.boozallen.com/media/file/issr-what-drives-program-costs.pdf . The method, as developed by Booz Allen Hamilton, aims for cost reductions not cost increases and uses the term "step change" in the sense of achieving major reductions, not incremental ones. The thrust of the approach

The concept describes a relationship whereby those cost drivers that have the greatest impact on cost are the most difficult to influence.

Huegin goes on to construct an elaborate scheme for scoring each step cost against the four categories in the methodology, setting them up as criteria. It aims thereby to demonstrate the shortcomings of our approach. However, Huegin's method seems to do nothing to answer the questions of how much savings ought to be recognised and when. We return to this point later in this review.

Huegin's analysis begs the question of why, if this analysis is valid for step changes, it should not be applied to EnergyAustralia's opex as a whole to determine the potential for improving the efficiency of the whole business – something that we understand to be a key purpose of the ISSR framework.

Other Comments on Huegin's Report

On p. 39 of its report, Huegin claims that the AER should undertake a detailed review of EnergyAustralia's step changes to identify and quantify potential savings and/or avoidable costs prior to adjusting the proposed operating expenditure.

In response, as far as we can see, EnergyAustralia **has not produced the information that would be needed for such an exhaustive task, it was not in our terms of reference to make any such detailed investigation for the AER and anyway, the businesses are in a much better position to undertake that type of analysis and present it in support of their cases.** [22]

Huegin makes detailed analyses and claims justification for each step change, in some cases citing and evaluating avoided costs. The justifications appear convincing, but again, there are no quantified benefits to be included in the projections.

Huegin says (p.73) that the majority of the network operating cost step changes are operational costs that result from approved capital investments and many are driven by external factors beyond the control of EnergyAustralia. We accept the point – that some step changes may be driven indirectly by external factors – and make adjustments for it later in this review.

On p.96, Huegin claims, "increases in EnergyAustralia's business support costs cannot be proven to be due to inefficiency from top-down analysis or comparison with heterogeneous peers. The magnitude of the increase, however, does warrant further investigation". For the avoidance of doubt, we have not suggested inefficiency anywhere; rather that efficiency could not be assured by the data adduced by EnergyAustralia.

The pages following in Huegin's report go into a considerable detail about business support expenditure, particularly relating to IT&T, but little or none of it appears to support EnergyAustralia's proposal of June 2008 in the way required for our analysis – through the quantification of efficiencies and benefits in terms of amount and timing and through clarification of how they have been allowed for in EnergyAustralia's projections.

8.3 Factoring In Future Efficiency Improvements

Whether in light of our questioning EnergyAustralia's step changes in opex, many of which were related to IT capex, or for other reasons, EnergyAustralia engaged PwC to prepare a case study in collaboration with EnergyAustralia's own staff to explain how future efficiency improvements were factored into its opex forecasts in the period FY 2009 to FY 2014. It was decided that the additional functionality proposed in the integrated asset management system (iAMS) would be

---

as envisaged by its authors is to look at all cost drivers, starting with the "platform design", i.e. not just at incremental opportunities for savings.

[22] See also the discussion on p. 6 under the heading "Benchmarking a Practical Tool to Assess Cost Structure as a Whole".

the subject of the study. PwC's report was attached to EnergyAustralia's submission of January 2009. [23]

The report purports to show how EnergyAustralia incorporated anticipated efficiencies from 'rolling out' iAMS but it appears merely to reflect statements by EnergyAustralia's staff that: iAMS would enable EnergyAustralia to operate at more efficient levels in the future, EnergyAustralia is passing on efficiency gains to customers by proposing lower levels of opex than it would otherwise, and projected opex would have been higher but for the roll-out. [24]

It concludes: "Overall, based on the information that has been provided to PwC by EnergyAustralia, the operating cost forecasts for a sample of line items from EnergyAustralia's proposal recognise some efficiencies anticipated from the roll-out of iAMS and the additional functionality proposed for this system. However, the extent of efficiency gains attributable to iAMS is not readily quantifiable due to iAMS being implemented concurrently with a number of other efficiency reform programmes."

It would have been more helpful if the report had attempted to indicate the scale and timing of the benefits but it did not do so.

Summary

In summary, the case study appeared to be overly dependant on advice from EnergyAustralia, made no attempt to indicate the scale and timing of the benefits and stopped short of investigating the broader implications of the iAMS rollout. For example, we would have expected that the consolidation of existing systems – which, presumably, have opex associated with them in the base year – would need to be recognised if they cease but they are not estimated or disclosed.

8.4 Large Scale Investments in IT and Reductions in Opex

EnergyAustralia's January 2009 submission (p. 90) says that to assess our assertions that large-scale [IT] investments should deliver reduced operating costs, it engaged Concept Economics to provide advice about how operating efficiencies are achieved over time, and particularly during periods of high capital investment. Concept Economics' report was attached to the submission. [25]

Concept Economics claims "One possible analysis is that high levels of capital expenditure, and the introduction of technological innovation, would (all else being equal) justify lower operating cost forecasts and more aggressive assumptions on future productivity gains. This analysis relies on the narrow and basic applications of concepts of economies of scale and scope. Yet closer economic analysis and empirical evidence focused on the observed relationship between high capital investment in goods and services of the type that make up a large part of EnergyAustralia's non-system costs, suggests this approach may be misleading."

Two of Concept Economics' conclusions, cited by EnergyAustralia, are that "without complementary investments (i.e.: associated operating expenditure), core IT systems can fail to deliver benefits of investment for customers or to the business" and "productivity gains driven by technology investments are not instantaneous but rather, a lag between the primary and complementary investments and those investments reaping efficiency gains is normal".

EnergyAustralia claims that this advice supports its view that a transitional phase of IT implementation would not immediately lead to a conclusion that a business can lower its forecast costs after IT investment because the business becomes instantaneously more efficient.

---

[23] *"EnergyAustralia's approach to incorporating efficiency gains into operating expenditure forecasts utilising its integrated asset management systems"*, PwC, January 2009.

[24] PwC explained the nature of the project but we were already familiar with that through our work in 2008.

[25] *"Operating efficiencies in periods of high investment and technology change"*, Concept Economics, January 2009.

EnergyAustralia claims that this also demonstrates that it would be imprudent to apply a high-level efficiency adjustment given that there is a lag between investment and efficiency gains and that efficiency gains are not exclusive to a lower forecast of operating expenditure across the business.

It claims that the advice also demonstrates that businesses in other industries recognise the long-term value and benefits of investment in large-scale investments in IT that go beyond a lower operating expenditure forecast.

It acknowledged the acceptance by us and the AER of a heavy investment in IT capex but claims that the advice of Concept Economics "provides a theoretical and empirical basis for supporting the prudence and efficiency of our forecast process".

Observations

Our main observation is that the matters discussed are conceptual and that EnergyAustralia draws a long bow in making its final statement above – that the advice received provides a basis for supporting the prudence and efficiency of its forecast[ing] process [and, implicitly, of its requested opex step changes for IT-related expenses].

We do not accept the claim that the high-level conceptual picture that has been painted by EnergyAustralia and its advisers ought to excuse EnergyAustralia from identifying the expected benefits and savings or quantifying (or at least attempting to quantify) the benefits and savings that it expects will be realised from its IT capex programme, or from stating the times at which the benefits and savings are expected to be realised. Were these requirements to be excused, it would imply that:

(a) even the vaguest assurances of future materialisation of cost savings and benefits ought to be accepted by regulators or advisers assessing the efficiency of expenditure, without any requirement for their quantification or possibly even their identification; and

(b) customers would bear the full risk of the un-identified or non-quantified potential efficiency gains or benefits being realised in the future.

We considered it necessary, for the purpose of our work, to ask for this information but as already reported, we found that no such detailed information had been supplied.

8.5 NERA's Critique of Assessment of Step Changes

EnergyAustralia asked NERA to review its January 2009 response to the AER's draft determination and the general points raised in the analysis in our Final Report. NERA's report on these matters was appended to EnergyAustralia's further submission of February 2009. [26] The report appears to deal with principally with regulatory and economic matters but some statements in it relate to our work on which we would like to comment.

Continuation of Status Quo Not Implied

NERA claims in section 3.2 of its report (p. 10) that "'step change' analysis assumes that maintaining the status quo in terms of expenditure will give rise to the status quo in terms of outputs (i.e., reliability, capacity, etc). This is the implicit counterfactual upon which the AER and Wilson Cook analysis relies".

It does not follow to us that maintaining expenditure levels through time leads to a continuation of the status quo in terms of the quality or volume of outputs. The contents of any particular expenditure budget may well be expended in new and better ways that lead to improved results without increasing the budget for the next 'n' years, i.e., without a step change in expenditure. Indeed, good managers strive continually to improve the efficiency with which they employ the resources entrusted to them, including money.

---

[26] "*Critique of the AER and Wilson Cook assessments of the prudence and efficiency of step changes in opex: a report prepared for EnergyAustralia*", NERA, February 2009.

No Evidence of Outcomes in Absence of the Expenditure

NERA claims at the end of section 3.2 that "In [its] opinion, the AER's conclusion on whether the proposed step change expenditure is prudent and efficient therefore needs to consider both what service outcomes would be delivered in the absence of the expenditure… and the evidence presented on what overall operating expenditure levels would be in the absence of the proposed expenditure."

We do not recall finding any explicit and/or quantified evidence of what the outcomes or expenditure levels would be in the absence of the proposed expenditure.

Present Value of Delayed Benefits Might Not Justify the Expenditure

In section 3.3 of its report, NERA says "Wilson Cook states that such efficiencies should 'off set' the proposed step change in operating expenditure. This implies that the associated efficiencies should be achievable within the same regulatory period as the planned expenditure".

Our statement does not necessarily imply any such thing – that is NERA's inference. We infer that there should be future benefits, some of which we would expect to be in the regulatory period because, if the majority of them were realised far in the future, their present value might not justify the expenditure.

Insufficient Time for Examination of the Report

We did not have time to examine NERA's report in any further detail, as it was received only a week before our reporting deadline. Therefore, if its findings are found later to be material to the determination, the AER should consider providing further time for its more detailed analysis.

8.6 Reassessment of Step Changes

Summary of Factors Considered in Final Report

We recommended in our Final Report a reduction of $284 m in EnergyAustralia's opex over the next regulatory period due to the removal of step changes. That opinion was reached after adjusting the base year opex for non-recurring and abnormal items, taking into consideration the criteria we set for acceptance of a step change, the large increase on historical expenditure arising from the application of step changes and the absence of quantification of benefits to be obtained from the extra IT capex, as expressed to the AER in our Final Report. [27]

We noted various general points in relation to the principles adopted for our consideration of the step changes in our Final Report, particularly on p. 51 of that report, as already discussed in this review.

January and February 2009 Submissions and New Information

EnergyAustralia has argued in its submissions of January and February 2009 to the AER that a number of step changes in its opex should not have been removed in the AER's draft determination. It claims amongst other things that the criteria applied for assessing the step changes were too narrow, resulting in prudent expenditure being rejected because it was characterised as a step change rather than being assessed on the merits of each forecast cost.

EnergyAustralia provided an alternative assessment of the step changes by Huegin that, it claims, supports a large proportion of the proposed step changes.

EnergyAustralia also submitted reviews by PwC, Concept Economics and NERA that, it claims, support its contention that benefits from the capital expenditure on new IT systems will not result in immediate cost savings and may increase costs in the short term although they are said to bring long-term benefits.

---

[27] See section 9 of volume 2 of our Final Report.

The reports by Huegin, PwC, Concept Economics and NERA have been discussed in more detail in the preceding sections of this review but are noted again here for completeness.

Reassessment of Criteria for Evaluating Step Changes

Having reviewed the material provided by EnergyAustralia and its advisers, we then considered whether changes were needed in the criteria used to assess the validity of step changes or in the method by which they were applied.

Principal Objective of our Review

We noted that the principal objective of our review was to determine the prudence and efficiency of EnergyAustralia's proposed expenditure and we considered that the test was required of the expenditure (opex, in this case) as a whole, not merely part of it.

Development of Criteria in Final Report

It was for this reason that we had taken the total base year opex, adjusted it to remove non-recurring items, confirmed its efficiency in relation to its peers by benchmarking, then considered all the changes that were proposed to it through to the conclusion of the next period.

As already explained, we had considered in our 2008 review that if the efficient starting position – opex in the base year – was to remain efficient over the next period, the test of additions to it ought to be stringent and we have already discussed in this review the reasoning used in our Final Report to arrive at the criteria and to apply them.

Review of the Criteria

We considered that the criteria stated in our Final Report for acceptance of a step change remained appropriate but that they ought to be expanded to clarify our intended interpretation and to deal with certain situations explicitly.

Huegin's Criteria do not Consider Efficiency

We did not accept that Huegin's alternative criteria for assessing the step changes were appropriate, as they do not consider efficiency but are predicated on "need" and "avoidability". Neither of those is adequate when considering efficiency, the evaluation of which, as we have already explained, is the subject of our review. Considerations of efficiency must, of course, start with necessity but must go on to consider the consistency of the expenditure with the business' broad objectives and policies, identification of the least-cost solutions for addressing the stated needs, and calculation of internal rates of return to establish that the investments are warranted.

Huegin's criteria do not reflect our efficiency objective and are not suitable for use in our review.

Revised Criteria

The revised criteria that we propose to address EnergyAustralia's concerns in relation to its step changes are set out below. They are for application after the business has demonstrated: (a) that it has adjusted its base-year expenditure to remove items that were abnormal or will clearly not recur [28] and to add items that would normally be present; [29] and (b) that the step changes do not duplicate any allowances for workload escalation or inflation in the next period that have been applied separately.

For a step change to be accepted, the business should then be able to demonstrate that:

(a) it is related to a fundamental change in the business environment arising from outside factors or offset by cost efficiencies in other areas (the original criterion);

(b) it is attributable to the imposition of new or changed obligations due to external factors including, if relevant, mandated improvements in service levels (an extension of the interpretation of (a) above);

[28] Done in our Final Report as a precursor to the step change analysis.

[29] None identified in our Final Report but some identified in this review.

(c) it is of a type that will improve service levels voluntarily as opposed to being mandated – in respect of which customers' willingness-to-pay for the improved service should be demonstrated (a further extension of the first criterion);

(d) it will bring cost savings or benefits to customers – in respect of which, the business should be able to demonstrate that: (i) it is continually looking for better ways of using its resources and improving its processes and systems to improve service levels or achieve cost efficiencies; (ii) it has defined the savings and benefits in terms of their nature and the expected time if their realisation; and (iii) where the savings and benefits are quantifiable, they have been quantified in sufficient detail for cost-benefit analyses to be prepared and that the cost-benefit analyses justify the investment; or

(e) alternatively, if it does not meet any of these criteria, the business has demonstrated that it will continue to operate efficiently as a whole, despite the cost increase.

In relation to criterion (d) above, we agreed with the repeated statement of the obvious by EnergyAustralia's advisers that some benefits might be delayed in time – in other words, that there may be a lag in their realisation, subject to the following qualifications. First, we noted that many of the investments proposed have been planned for implementation at or near the beginning of the period under review (FY 2010 to FY 2014) **and we considered it reasonable to expect that the benefits would accrue or at least begin to accrue before the end of the period.** Second, we noted that **the general premise – that benefits would be delayed – would not apply to all types of benefit.**

We also reiterate the point made earlier in this review that **the present value of benefits that are delayed substantially might not be sufficient to justify the investment**.

For the avoidance of doubt, we considered that satisfaction of criterion (e) could be achieved only by a robust benchmarking of the business' *future* costs over the regulatory period, sufficient to demonstrate its continued efficiency in comparison with industry norms.

In relation to all criteria, **we considered it necessary to identify evidence of compliance with the criteria, including in relation to the quantification of benefits as envisaged in criterion (d).**

Application of Revised Criteria and Reassessment of Step Changes

Summary

We reassessed the step changes in light of the revised criteria set out above and, based on them and the new information presented in EnergyAustralia's submissions, accepted some additional step changes.

Notwithstanding claims made to the contrary by EnergyAustralia, we still did not find any evidence that EnergyAustralia has quantified (i.e. shown numerically) or attempted to quantify the cost savings and benefits claimed to be associated with step increases in cost that arise from changes in businesses processes and systems, nor shown where it had allowed for them in its estimates of opex for the period FY 2010 to FY 2014, and so we do not recommend acceptance of the remaining step changes. [30]

Nor did we find any evidence that improved customer service standards or reliability targets were signalled or included in EnergyAustralia's performance targets because of the expenditure proposed.

Although we reviewed it again, we still did not consider that EnergyAustralia's response to our question of "whether any productivity improvements [had] been allowed for over the next regulatory period [in relation to opex]" demonstrated a tangible connection with the opex step

---

[30] In one instance, "incremental IT capex (corporate systems)", Huegin identified $4.2 m of "productivity savings" but the description of the item as "retirement of hardware" suggested that it could not be considered a productivity improvement. See pp. 54-55 of Huegin's report.

changes that we have not accepted (which relate almost exclusively to IT), as the response was presented in terms of "sectoral efficiency" (which dealt with efficiency only at a global level), "specific productivity initiatives" (which identified "projects currently in place to improve efficiencies within current resource limits" as being "the standardisation of designs, streamlining of planning and approval processes and increased use of external contractors for major projects", none of which have any direct connection with the claimed efficiency impact of expenditure on IT systems. [31] [32]

Although we reviewed them again, **we still did not consider that EnergyAustralia's supporting documents specifically related to IT were strong on opex**. Generally, they went into considerable detail on capex but the opex side of the projects was minimal, as already observed in this review.

We therefore considered that EnergyAustralia's step changes related to IT expenditure failed our test and so we did not accept them in our Final Report. Nor do we do so now.

Step Changes in Network Operating Expenditure

In the network operating expenditure category, we have now identified one additional step change that could be considered an adjustment for an abnormal item in the base year. It relates to the reversal of an insurance credit.

There are also several step changes in the category that could be considered to be driven by external obligations, as they arise from EnergyAustralia's increased system capex programme. It, in turn, is driven, at least in part, by changes in the licence conditions applicable in NSW. We have thus accepted the increases in cost associated with system and non-system property as they appear to be related primarily to the increased system capex programme.

That part ($0.8 m) of the corporate IT cost increase related to "mandatory requirements from a directive from the Premier" or words to that effect also appears to fall into this category and is now accepted.

For the record, the incremental apprenticeship costs, which were accepted in our Final Report, could also be considered to fall into this category. [33]

However, as already stated in this section of the review, the remaining step changes proposed under this category are not accepted as they relate to changes in business processes and systems – principally, IT systems – and have not been demonstrated to meet the requirements of criterion (d) and are not accompanied by a demonstration of compliance of the business as a whole with the alternative criterion, (e) –to the contrary, on the last point, our observation (which was stated clearly in our Final Report) is that it was hard to see how EnergyAustralia could claim to still be operating efficiently at the end of the next period, given the significant forecast increase in its opex over the period.

Our revised network operating expenditure adjustment is shown in the following table. Cost escalation has been applied as in our Final Report.

---

[31] We had considered this response in our 2008 review.

[32] We noted Huegin's arguments on efficiency, e.g. in section 5.2.1 on p. 77 of its report, but we also noted that the argument was restricted to a narrow field – maintenance costs in the base year – and did not address the efficiency of EnergyAustralia's opex as a whole. Nor were the matters analysed related directly to the IT expenditure under consideration.

[33] EnergyAustralia questioned why they had been approved when other step changes had not.

YE 30 June	2008	2009	2010	2011	2012	2013	2014
Total proposed step changes	14.44	17.06	14.33	2.75	(1.76)	0.57	(1.01)
less step changes accepted in final report							
Incremental apprenticeship costs	(4.25)	(2.72)	(1.32)	(0.56)	(0.54)		
less additional step changes now accepted							
Property - system land tax	(0.92)	(1.21)	(1.00)	(0.13)	(0.03)	(0.03)	0.02
Property - system council rates	(0.02)	(1.11)	(0.12)	(0.01)	(0.03)	(0.01)	0.02
Property - system water rates		(0.41)	(0.03)				
Property - system maintenance	(0.15)						
Property - system rent	(0.18)						
Property - electricity	(0.95)	(0.47)					
Property - non system maintenance	(0.52)	(1.65)	(0.51)				2.42
Property - non system rent	0.05	(0.64)	(1.67)	0.24	0.96		
Property - environment			(0.31)				
Corporate IT&T (CIO)		(0.82)					
Insurance	(1.35)	(0.13)					
Property - non-system land tax	(0.22)	(0.06)	(0.36)	(0.11)	0.12	0.12	0.03
Property - non-system council rates	0.03	(0.21)	(0.15)	0.03	0.08	0.03	
Property - non-System water rates	(0.04)	0.09	(0.04)	0.01	0.02	0.01	
Balance of step changes - to be removed	5.9	7.7	8.8	2.2	(1.2)	0.7	1.5
Cumulative total of items to be removed	5.9	13.6	22.5	24.7	23.5	24.2	25.7
Cost escalator			1.037	1.048	1.057	1.069	1.068
Escalated cumulative total			23.3	25.9	24.9	25.9	27.4
Revised adjustment			**(23.3)**	**(25.9)**	**(24.9)**	**(25.9)**	**(27.4)**

Step Changes in Maintenance Expenditure

Two step changes were proposed in the maintenance expenditure category: technical publications and third party damage. Neither was accepted in our Final Report but a case can be made to attribute both to abnormal expenditure in the base year, the technical publication item being due to a large credit posted to that item in the base year. We have therefore accepted it now.

The figure for third party damage is also accepted now but with an adjustment to bring it into line with Huegin's finding that it "appears to be approximately 39% higher than the forecast required to bring the expenditure up to the historical average". [34]

This adjustment in this category is therefore minus $0.8 m p.a., being 39% of the $2.1 m requested for third party damage.

Step Changes in Other Operating Expenditure

We have identified a further step change in the "other operating expenditure" category that could be considered adjustments for abnormal items in the base year and accepted. It is "network business reliability and other" and relates to the write-off of bad debts.

Three step changes that appear to be related primarily to external obligations – "customer relations - EWON fee", "metering and connections - GCSS claims" and "customer operations - emergency services" – are now accepted.

The incremental regulatory cycle costs accepted in the Final Report also fall into this category.

Several relatively small step changes have been applied in lieu of workload escalation. We have accepted these as a substitute for growth escalation in the expenditure categories concerned. They include incremental meter reading - new customers, incremental meter reading – conversions, metering and connections – policy and procedures, customer operations – customer support, corporate finance function, corporate HR, corporate secretariat, media and internal communications and internal audit.

34 p. 87 of Huegin's report (note: the axis in the graph is misaligned by one year.)

The asymmetric risk and self-insurance step changes were not reviewed by us and so have not been refused in our assessment.

On checking, we found workload escalation had not been added to step changes, so the adjustment for that has been removed.

Our revised adjustment for other operating expenditure is shown in the table below.

YE 30 June	2008	2009	2010	2011	2012	2013	2014
Total proposed step changes	7.8	2.4	6.5	0.1	1.2	2.2	(1.6)
less step changes accepted in final report							
Incremental regulatory cycle a/	(2.4)	1.6	1.3		(1.0)	(2.1)	1.5
Asymmetric risk and self insurance a/			(5.6)				
less additional step changes now accepted							
Customer relations - EWON Fee		(0.3)					
Network business - reliability & other	0.8						
Metering and connections - GCSS claims	(0.9)		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Customer operations - emergency services	(0.2)	(0.3)					
Step changes in lieu of escalation	(1.7)	(2.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Balance of step changes - to be removed	3.5	1.3	2.1				(0.2)
Cumulative total of items to be removed	3.5	4.8	6.9	6.9	6.9	6.9	6.7
Cost escalator			1.072	1.087	1.106	1.128	1.138
Escalated cumulative total			7.4	7.5	7.6	7.8	7.6
Proposed adjustment			**(7.4)**	**(7.5)**	**(7.6)**	**(7.8)**	**(7.6)**

a/ Not assessed by Wilson Cook & Co.

8.7 Capex-Opex Trade-Off (SKM Report)

Background

In its submission of June 2008, EnergyAustralia proposed that its maintenance operating expenditure be adjusted over the next period in accordance with a set of curves that it had determined, relating maintenance expenditure to the average age of its network fixed assets. [35] Separate curves were determined and applied to each of six asset groups, based on work undertaken for EnergyAustralia by SKM. The shape of the maintenance cost *vs.* age curves were said to be exponential based on SKM's work.

The maintenance costs for new assets, expressed as a percentage of replacement cost, have been calculated by SKM using year 2002 data whereas the cost of maintaining older assets uses 2007 data.

The method applied by EnergyAustralia was to determine exponential curves, one for each of the chosen categories, each fitted to two points, the first point being the maintenance cost of new assets (of age zero) and the second being derived from the combination of (a) its records of maintenance expenditure on each of the six groups in FY 2007 and (b) the average weighted age of the assets in each group at that time. EnergyAustralia then projected its future maintenance costs by applying, to the developed curves, the changed average weighted ages of each of the asset groups in each future year. The average weighted ages in future years took account of the planned level of asset replacement in each asset group during the period.

The effect of this was to increase forecast maintenance costs each year, since the rate of planned replacement in most asset categories was insufficient to arrest the increase in average weighted asset age, resulting in a net movement "up" the exponential cost-age curves.

[35] See "Network maintenance capex opex trade-off model" in its June 2008 proposal.

We reviewed this capex-opex trade-off model and considered it insufficiently robust for the intended purpose, concluding that the resulting maintenance cost forecasts were likely to be overstated.

In place of EnergyAustralia’s modelling, we calculated the indexation of maintenance costs in accordance with network size and proposed, after consideration of related factors, a compromise at the mid-point between the size indexation increase that we had calculated and the modelling used by EnergyAustralia, resulting in a recommended net reduction of $18 m over the period. [36]

The issues cited by us in making our adjustment have already been noted in this review and included the questions:

- whether the costs of maintaining new assets are comparable with the costs of maintaining old assets, as this affects the calculation of the “new asset” point and the relationship between it and the FY 2007 cost point on the cost-age relationship curves,
- whether it is valid that the relative costs of maintaining new assets as a percentage of replacement cost, calculated in FY 2002, are relevant, given the significant change in asset replacement costs over the intervening years,
- whether the maintenance costs calculated for FY 2007 are efficient, given that EnergyAustralia was, at that time, in the process of catching up a maintenance backlog from FY 2006 and,
- why the relationship curves should be exponential.

In relation to the last point, we noted that exponential growth in expenditure of any type seldom occurs in reality.

We also noted in our Final Report that, upon analysis, we could not find evidence of an exponential relationship between average network age and direct maintenance cost in New Zealand electricity distribution company data, for which suitable information was available for analysis; and, if anything, a linear relationship appeared to be more convincing.

SKM’s Response

SKM was asked by EnergyAustralia to comment on the following matters in relation to our Final Report: whether the cost of maintaining new assets is comparable with those of maintaining old ones; why the curve should be exponential; why, as a result of analysis of NZ DNSPs, the age/cost trend is closer to linear than exponential; and that there is doubt about the robustness of EnergyAustralia's analysis (based on SKM's work) to derive a workload escalator for maintenance (based on the O&M / age cost curves).

As part of its submission of January 2009, EnergyAustralia tabled the response from SKM and we have reviewed it and comment as follows. [37]

Our Reassessment

sComparability of Maintaining New and Old Assets

Section 5.3 of the SKM report argues that the cost of maintaining new network assets is, in general, lower than the cost of maintaining older ones due to changes in technology. SKM claims to support this view from its own experience and claims that a body of technical literature supports its argument.

SKM claims “...it is likely that the opex-age curve exhibits both age-related cost increases (likely to be exponential) and also technology-related increases (likely to exacerbate the age relationship

---

[36] EnergyAustralia had, separately, made corrections (a reduction of $24 m) due to other reasons, as discussed earlier in this review. The two corrections are unrelated.

[37] *“SKM response to Wilson Cook commentary on O&M / age profile modelling: final report”*, SKM, 5 January 2009.

further). SKM considers this is likely to move the overall relationship further away from a linear relationship."

We agree with the argument that new assets cost less to maintain than older equivalents and note that we never contended otherwise and that SKM appears to have misinterpreted our questioning of the comparability of maintenance costs between new and old assets.

We contend that it is because there is a difference in maintenance cost between new and old assets of the same type that it is not safe to apply a cost model using asset age when the model gradient is derived from mixed causes (*viz.* increasing costs with age and changing costs through replacement with new technology).

The key point to note is that, with time, an asset will increase in age but not change in technology. For example, an air-insulated circuit breaker ageing from 20 to 25 years does not transform itself into a circuit breaker of another type such as an older, compound-filled type with an accompanying higher maintenance cost.

We contend that EnergyAustralia's model is likely to overstate the rise in maintenance cost with increasing average age because the gradient derives from these mixed effects – age and technology – and therefore overstates the effects of ageing alone.

A more tenable model would identify and apply, separately, the effects of ageing for assets of the same technological group and the effects of new technology under the asset turnover mechanism and not the asset ageing mechanism.

Assumption of Exponential Curve

SKM's modelling assumes an exponential relationship between average asset maintenance costs and average asset age. An exponential relationship is one that is characterised by a continuously increasing gradient. Because EnergyAustralia's average network age is projected to increase over the next regulatory period, application of the exponential relationship results in the derivation of a greater increase in average maintenance cost compared to that which would be derived if, for example, a linear relationship had been applied with the same starting point and initial slope.

SKM claims that whilst "...it has been cautious about claiming any degree of accuracy in the shape of the curves, particularly at the high end" and "...it is difficult to find sufficiently detailed data in the right format to allow analysis that would definitely prove either a linear or exponential relationship (or other)" [38] it nevertheless considers an exponential relationship to be more likely than a linear or other one and that it is a reasonable approximation. SKM bases this assertion on its own experience, analysis of case studies where data is available, and the weight of reliability theory.

We do not comment on SKM's experience, other than to note again that it is our view that exponentially increasing costs are seldom observed in practice.

We note that whilst it may be tempting to fit an exponential relationship to a cost-age characteristic that is flat or linearly rising in the initial years but which exhibits steep increases near the end of life – a common situation – it is not generally safe to do so. This is because such a fit over-emphasises the end-of-life characteristic that applies only to a small proportion of the asset population. This is acknowledged by SKM in section 4.2: "*...with ageing assets being replaced as they approach their economic life, the numbers of assets at the 'top end' of the curve are generally quite low*".

Fitting an exponential relationship applies an increasing gradient to the *whole* age span but the majority of the assets are unlikely to be described correctly by such a relationship.

This is evident in SKM's second case study in section 4.7.2 of its report, where the rising cost trend is applicable only to assets of greater than 50 years in age (and even then, it is seen to be

---

[38] SKM's report, section 5.1.

volatile). For assets in the range of age of 5 to 45 years, where the bulk of the assets are expected to reside, the defect rate with age is flat.

Other case studies presented by SKM are also open to alternative interpretations in this regard. For example, the third case study in section 4.7.3 of the report discusses circuit breaker maintenance costs, to which SKM has ascribed an exponential relationship as the best fit. Our examination of the cost-age chart provided in this example suggests that the exponential fit is overly influenced by the maintenance characteristics of 66 kV breakers that make up only a small portion of circuit breaker population. Circuit breakers of other voltages are more common and do not show an exponential characteristic.

Distinction between Failure Time and Failure Rate

In section 3.1 of its report, SKM claims to support its assertion of an exponential relationship between cost and age by referring to technical sources "*...There are a number of highly respected technical sources however (including CIGRE) which make reference to failure **rates** of electrical equipment being exponential in nature*" – our emphasis added. It further claims in section 4.1 that "*...The relationship most commonly used to describe wear-out failures is exponential, or some related variation (such as a Weibull curve with a shape factor close to that describing an exponential)*". We acknowledge that the technical literature often characterises failure **times** as being exponential or Weibull distributed for certain asset types but do not agree with the conclusion that SKM draws from it, noting that a distinction needs to be drawn between failure **times** on the one hand and **rates** on the other. Failure times refer to the time elapsed before the failure of an asset occurs and are thus related to age, whereas the failure rate is the ratio of the number failing in a given time interval to the number present at the beginning of that interval. SKM appear to have confused the two.

Various technical sources and our own analysis support the conclusion of exponentially distributed failure **times** for electrical equipment such as circuit breakers but that is **not** the same as concluding that the failure **rates** of the assets increase exponentially. Exponentially distributed failure **times** are a special case of the Weibull distribution where the shape factor (beta) is unity.[39] With exponentially distributed failure **times**, the failure **rate**, is constant over time. To illustrate this with an example: a fixed population of assets will decrease in number over time as its members fail. The number failing in any given time interval over time will show as the distribution of failure **times**. For example, starting with 1,000 items and a constant failure rate of 10% p.a., 100 items will fail in the first year (1,000 x 10%), 90 in the second year (1,000-100 = 900 x10%), 81 in the third year, etc. The distribution of failure **times** is exponentially decreasing but the failure rate is constant.

It appears to us that SKM is confusing exponentially distributed failure **times** with exponential failure **rates**.

If SKM accepts that the relationship most commonly used to describe wear-out failure is exponential or is a Weibull curve with a shape factor close to that describing an exponential curve, as stated in section 3.1 of its report, then SKM ought to have concluded that the relationship describing the failure **rate** against age, and therefore the implied cost of failures against age, is flat or linear. [40]

Analysis of Data for New Zealand Electricity DNSPs

To further test EnergyAustralia's cost-age model, we examined data from other DNSPs to evaluate the assertion that average cost and average age were exponentially related. Data from

---

[39] See: *"Applied Life Data Analysis"*, Nelson, John Wiley & Sons, 1982, ISBN 0-471-09458-7, p. 40.

[40] Costs arising from failures will be determined by both the failure rate with age and the age profile of the asset population. For clarity, when discussing the cost effects of failure rate alone, we assume that the age profile of the asset population is flat.

DNSPs in New Zealand was examined because of its availability and comparability. [41] We reported the findings in our Final Report, noting that the data did not support the assertion of an exponential relationship and, if anything, a linear relationship was more likely.

In section 4.6 of its report, SKM claims amongst other things that our analysis did not meet the level of rigour needed to reject EnergyAustralia's analysis. The principal reasons cited for that claim were alleged differences between the scope of New Zealand and Australian maintenance work and work practices, alleged unaccounted-for differences between network types, e.g. urban and rural, alleged small differences between average network ages providing low resolution for determining trends, a claim that the alleged use of only two years of data was insufficient to conclude trends, and an alleged simplistic normalisation of network size based on installed transformer capacity.

SKM claims that there are unaccounted-for differences in the scope of maintenance work and work practices derived from different regulatory and physical environments, claiming that Australian utilities have higher maintenance expenditure in vegetation management. However, having experience with DNSPs in both countries, we are of the view that the degree of similarity in the scope of maintenance work and work practices is greater than the degree of difference.

We also note that vegetation management costs are or should be uncorrelated to network age and that a lower relative proportion of vegetation management costs in the New Zealand environment (if that is the case) would tend to highlight, rather than disguise, relative cost differences derived from different network average ages.

Our analysis accounts for differences in network type by grouping networks based on ratio of line length to installed transformer capacity, thus differentiating between urban and rural networks.

Differences in average network ages between the DNSPs examined, derived from the comprehensive up-to-date network fixed asset valuation records available for all the DNSPs in New Zealand, had an approximate range ratio of 1:2, that is the oldest network had approximately twice the average age of the youngest, providing sufficient range to examine the existence or otherwise of trends.

The use of installed transformer capacity as a normalising variable was examined, concluding it was the most appropriate variable within the data set to normalise the direct costs.

The 2005 and 2006 years data referred to in our analysis are data sets collected in these years, each comprising dispersed costs and ages upon which trends were examined. Two data sets were examined to provide a level of assurance that the observations were consistent between data sets collected in different years.

Criticisms expressed in the SKM report in section 4.6 appear to interpret our analysis as relying on two consecutive points for the determination of trends but that is not the case.

SKM is incorrect in implying in section 4.6 of its report that we relied on the comparative analysis of New Zealand DNSPs to reject the EnergyAustralia’s analysis and substitute a linear relationship. We referred to the New Zealand data only to illustrate that it supported our general contentions and thus added weight to our concerns that SKM’s analysis was, in our opinion, flawed.

Incorrect Gradient of the Curves

An additional concern noted in our Final Report was whether maintenance costs calculated from FY 2007 data were efficient, given that EnergyAustralia was, at that time, catching up on a maintenance backlog from FY 2006.

A further concern noted in our Final Report was whether it was valid for EnergyAustralia to have used SKM’s 2002 data when determining the maintenance costs of new assets as to have done so

[41] It is disclosed publicly in accordance with carefully prescribed requirements, as part of the regulatory framework in that country.

was likely to have understated that cost and improperly steepened the slope of the cost-age curves.

In essence, we considered that the using 2002 costs for maintaining new assets and 2007 costs for maintaining older ones was incorrect.

SKM claims to have addressed these points in its latest report. In section 5.2 of its latest report, SKM argues that if the costs used in the model were inefficient – SKM does not say that they are – then this would not affect the model materially as the inefficiency would apply over the whole opex-age curve and therefore not affect “relativities” in the relationship. In section 5.4, SKM claims that changes in replacement cost are not relevant as they would affect “scale, not relativity”, and the model is applied based on “relative movement”.

We do not agree with that claim, which fails, anyway, to address our point that the new asset point and the FY 2007 point have been calculated dissimilarly due to shifts that have taken place in replacement costs between the years used and therefore the gradient of the cost-age curve is incorrect.

As a further illustration of our point, it is obvious to us that escalation of SKM’s 2002 costs to 2007 prices would lift that point and alter the gradient in its analysis, so we do not understand why this obvious point is denied by SKM.

Other Problems with the SKM’s Analysis

Age and Technology Effects Not Separated

SKM states in section 5.1 of its report “The average annual percentage increase in costs applies to the network as a whole [referring to the model applying to an asset group], and if the average age is maintained will show no net increase in average opex costs.”

This does not appear to be true. Even if the average age were to be maintained constant, requiring a level of asset replacement matched to the ageing rate, old assets are still being replaced with new assets of modern technology with lower maintenance costs. Over time, the average maintenance cost will thus decrease as the asset population attains ever-higher proportions of modern assets.

In essence, the SKM model does *not* properly separate ageing effects and technology effects and is therefore not robust.

Failure Rate Not Applied to Population Numbers

Section 4.2 of the SKM report calculates the rate of change for a linear and an exponential hazard function and claims the declining rate of change evident in a linear hazard function is evidence of its dysfunction in describing changes in maintenance costs with age.

We do not follow SKM’s logic, as the charts it has provided for hazard function and rate of change are labelled in the same units. The rate of change, as charted, would appear to show the failure rate per age. We fail to see relevance of that as failure rate is usually applied not against age (which increases) but against population numbers (which decrease).

SKM’s analysis needs review in this respect.

Exponential Failure Rate does not Produce Weibull Distributed Failure Times

Section 4.7.1 of the SKM report correctly describes the failure rate formula that results in Weibull distributed failure times and correctly interprets that the failure rate is largely dependant on the shape factor 'beta'. With beta equal to one, the failure rate is constant with time; with beta equal to two, the failure rate increases linearly with time; and with beta equal to three, the failure rate increase with time is quadratic.

However, section 4.7.1 of the SKM report claims “...An exponential failure rate relationship is a special variation of the Weibull function which assumes that the failure rate increases over time and that the annual percentage increase is constant over the life of the asset”. That is incorrect.

An exponentially increasing failure rate does *not* produce Weibull distributed failure times. If an exponential failure rate is observed, it is more likely an Extreme Value distribution will fit the failure time observations.[42]

We are not aware of technical literature that supports the use of Extreme Value distributions in electrical equipment failures, although we have not researched this particular aspect exhaustively.

Conflicting Statements on Weibull Distribution Parameters

In section 4.7.1 of its report SKM notes that "...Academic research in this area indicates that typical values for the variable beta (a Weibull distribution parameter), for electricity supply industry equipment, fall in the range three to four, suggesting failure rates that increase with time".

This statement contradicts SKM's statement in section 4.1 that failures in electrical equipment follow Weibull distributions with beta values approximating the exponential distribution (i.e. beta approximating unity).

SKM does not provide references to the academic papers supporting the use of high range beta values for this type of equipment.

Our own experience suggests that where high range beta values are calculated, the failure times are better fitted with a distribution incorporating a natural age offset such as a Gaussian distribution.

Concluding Remarks

Having considered the arguments presented in SKM's report, our position remains that the EnergyAustralia maintenance workload escalation applied to its forecasts over the next regulatory period, as derived from its capex-opex trade-off model, is **not** robust and likely to overstate efficient costs.

8.8 Capex-Opex Trade-off (Huegin Report)

As a further observation in support of our assessment of EnergyAustralia's capex-opex trade-off (based, as it was, on SKM's work), we note that Huegin, in section 5.4 of its report, claims support for the application of exponential maintenance cost growth, citing support in technical literature for exponentially increasing failure rates in equipment and exponentially increasing maintenance costs with equipment age reported in the aviation industry.

Many of the issues raised by Huegin were those raised by SKM and our response to them is presented in the preceding section of this review. In relation to the claims raised only by Huegin or the data used only by it, we reply as follows.

Relevance of Aviation Industry Experience and Data

Huegin appears to have relied excessively on experience and data in the aviation industry but that industry differs significantly from the electricity distribution industry that is the subject of the present investigation.

We consider that an electricity lines business, with large populations of geographically distributed low value assets of conventional technology and the aviation industry, with its relatively small number of safety-critical, high value assets, are sufficiently different to make comparisons of maintenance cost behaviour erroneous.

Exponential Age Curve Relevant Only to Older Assets

Although Huegin appears to support the use of an exponential curve for maintenance cost vs. asset age, it notes that exponential equipment failure rates may occur only in older assets, saying, "*...We have also noted from our experience with developing models for optimal asset retirement*

---

[42] Nelson; Applied Life Data Analysis; 1982; John Wiley & Sons; ISBN 0-471-09458-7; pg 42

point decisions for several industries that many individual items of equipment exhibit exponentially growing maintenance costs beyond a particular age" (our emphasis added).

Huegin thus appear to agree with one of the principal points we made in the preceding section of this review – that an exponential relationship is not necessarily correct over the full life of assets as applied by EnergyAustralia.

Use of Incompatible Data

Huegin does not address the other specific issues raised in our Final Report; in particular, the incompatibility of using 2002 costs for maintaining new assets and 2007 costs for maintaining older ones. We have addressed this issue in the preceding section of this review.

8.9 Workload Escalation of Maintenance Costs

We have already dismissed in this review the claim that our adjustment of workload escalation of maintenance costs was incorrect in respect of the capex-opex trade-off relationship. [43]

We also reject the claim that the use of a mid-point between the two available estimates – EnergyAustralia's and ours – was wrong as well. It is common to accept a mid-point (or some other point) between the upper and lower bounds of calculation when there is reason to believe that neither bound is suitable for use without adjustment and where there is no better basis for determination. This was made clear in our Final Report (p. 56), in which we noted, "…replacement capex is directed heavily at transmission, sub-transmission and zone substation assets, not at distribution assets where it is expected that many maintenance costs lie. Taking these factors into consideration, some increase above that attributable to size alone can be expected. In the absence of better information, we took, as a reasonable estimate, an increase half way between the upper and lower bounds…"

The revised benchmarking reported earlier in this review has resulted in a change in the choice of size escalator in all our calculations and the adoption of the new basis – consumers and line km – leads to a slightly lower growth rate adjustment than the composite scale variable used in the Final Report did. This has the consequence of reducing the size-adjusted level and increasing the proposed reduction in this item from $18 m to $28 m, as shown in the following table.

	Proposed				
YE 30 June	2010	2011	2012	2013	2014
Mainteance escalator	1.072	1.080	1.1057	1.1243	1.1556
Size escalator	1.040	1.042	1.053	1.065	1.077
Mid-point	1.056	1.061	1.079	1.095	1.116
Mtce expenditure ($ m 2009)	217	223	233	242	253
Adjustment	**(3.2)**	**(4.0)**	**(5.5)**	**(6.4)**	**(8.6)**

8.10 Escalation of Asset Management and Major Projects Branch Costs

EnergyAustralia claimed in its January 2009 submission that our assessment of workload escalation for the Asset Management and Major Projects branches of the business was not appropriate.

The point that we had objected to in EnergyAustralia's original proposal was the use of real system capex as a driver of workload in these business units. We had noted that as presented by EnergyAustralia, large increases in capex were said to drive similarly large increases in the cost of these support services that, in our opinion, might not be appropriate. We considered that if the capex programme was driving those costs, they should be capitalised.

Irrespective of that, we did not consider in our Final Report that the relationship was as direct as assumed. In addition, we noted that project value *per se* was not necessarily an appropriate

---

43 See section 8.7.

measure of the resources required to oversee capital projects. We considered that this was confirmed by information on staff increases that did not show growth of the same magnitude as the capex programme. We considered that the increases were overstated and, accordingly, we calculated an adjustment by applying an escalator based on forecast changes in the network division staff instead of real system capex. [44]

January 2009 Submission and Additional Information

EnergyAustralia has claimed that we did not take account of its response to questions on the activities in these business units. It quotes its response in its January 2009 submission,[45] saying that: "…most of the costs associated with the branches are capitalised", "the operating costs relate to areas such as maintenance planning, reliability analysis and branch management", and "…it is expected that operating costs will increase in scale with the capitalised costs of the division. We consider there is a strong basis for this assumption, especially given that the operating activities will increase in line with the value of the capital program[me] activity: governance administration, monitoring and reporting of the capital program[me]; and updating of maintenance planning based on the implementation of the capital program[me]."

There appears to be a degree of conflict between these statements in relation to the nature of the activities associated with the opex costs that have been forecast for the two business units. The first statement confirmed that some capital-related activities were included but the other statements suggest that the activities of the branches are related mainly to administration, reporting and maintenance planning activities.

We do **not** accept that EnergyAustralia has justified the link between opex activities and capex adequately and we do **not** agree that opex activities should increase in line with real growth in the capex programme, as maintenance planning is likely to relate only to the overall increase in assets under management and that exhibits a much smaller expected growth rate.

If, indeed, some of the activities are directly related to the capital programme, we remain of the view that they should be capitalised.

We thus retain the view, set out on p. 11 and p. 32 of this report, that the relationship is **not** as direct as assumed; project value *per se* is **not** necessarily an appropriate measure of the resources required to oversee capital projects and their maintenance; **this is confirmed by information on staff increases** that does **not** show growth of the same magnitude as the capex programme; and thus **the increases appear to be overstated**.

Recalculation

In reviewing this matter, we noticed that the growth escalator should only have been applied to the variable component of expenditure, approximately 90.3% of the total. [46] We have therefore re-calculated the adjustment on this revised basis. The result is a decrease in the adjustment from $13 to $12m, as shown in the following table. [47]

---

[44] Final Report, p. 58.

[45] P. 102 of that submission.

[46] The weighted average for the two business units.

[47] EnergyAustralia included real cost escalation in its capex growth escalator. As previously reported, we do not consider that real cost escalation should have been included in the growth escalator. Its removal is, effectively, incorporated in the adjustment we have recommended.

	Estimated		Proposed				
YE 30 June	2008	2009	2010	2011	2012	2013	2014
Real capex growth	4.1%	12.8%	43.0%	9.3%	14.9%	1.9%	-12.0%
Escalator	1.04	1.17	1.68	1.84	2.11	2.15	1.89
Network staff growth	6.6%	3.6%	2.8%	4.4%	-1.4%	1.1%	0.5%
Escalator	1.07	1.10	1.14	1.19	1.17	1.18	1.19
Adjustment factor	1.02	0.94	0.68	0.65	0.55	0.55	0.63
Proposed cost ($ m 2009)			5.1	5.7	6.7	7.1	6.3
Adjustment			**(1.7)**	**(2.0)**	**(3.0)**	**(3.2)**	**(2.4)**

8.11 Adjustment to Opex – Conclusion

Taking into account the adjustments recommended in the preceding sections of this review, our revised “bottom-up” assessment of EnergyAustralia’s opex in the period is shown in the following table. The net adjustment is a reduction of $209 m compared with the adjustment of $316 m recommended in our final report. The principal cause of the change is the reassessment of the step changes.

YE 30 June	2010	2011	2012	2013	2014	Total
Opex proposed by DNSP	558	574	593	616	632	2,972
Capex / opex trade-off reduction	(3)	(3)	(4)	(6)	(8)	(24)
	555	571	588	610	624	2,949
Proposed adjustments:						
Step changes						
- Network operating cost	(23)	(26)	(25)	(26)	(27)	(127)
- Maintenance	(1)	(1)	(1)	(1)	(1)	(4)
- Other operating costs	(7)	(8)	(8)	(8)	(8)	(38)
Workload escalation						
- Capex / opex trade off a/	(3)	(4)	(6)	(6)	(9)	(28)
- Asset & project management	(2)	(2)	(3)	(3)	(2)	(12)
	(36)	(40)	(42)	(44)	(47)	(209)
Pct of proposed opex b/	(7%)	(7%)	(7%)	(7%)	(7%)	(7%)
Adjusted "bottom-up" opex	**519**	**531**	**547**	**566**	**577**	**2,740**

a/ No adjustment has been made to this line for modifications, if any, in the capex programme presented in EnergyAustralia's original expenditure proposals as reviewed by us.
b/ Was 11% in Final Report.

We have also re-calculated our “top-down” analysis by applying the revised growth escalator derived from the new regression analysis. In addition, we considered that the “top-down” calculation should take account of the step changes that are accepted (other than those used as a substitute for workload escalation), as they represent additional costs imposed, essentially, by external obligations. The revised “top-down” calculation is shown in the following table.

YE 30 June	2010	2011	2012	2013	2014	Total
Opex proposed by DNSP	558	574	593	616	632	2,972
Capex / opex trade off reduction	(3)	(3)	(4)	(6)	(8)	(24)
	555	571	588	610	624	2,949
Opex calculated by escalating base year by size growth:						
Normalised base year	423	423	423	423	423	2,117
Cost escalation	8%	9%	12%	14%	17%	
Size escalation	3%	4%	5%	7%	8%	
	469	482	497	516	533	2,497
Allowed step changes	33	34	35	37	33	172
Calculated "top-down" opex	502	516	532	553	566	2,669
Reduction	(53)	(55)	(56)	(57)	(58)	(280)
Pct of proposed opex a/	(10%)	(10%)	(10%)	(9%)	(9%)	(9%)
Adjusted "top-down" opex	**502**	**516**	**532**	**553**	**566**	**2,669**

a/ Was 14% in Final Report.

The level of opex derived from the “top-down” analysis is 2.6% below that derived from the “bottom-up” analysis (compared with 3.5% in the analysis in the Final Report), and again suggests that the “bottom-up” analysis is not unreasonable.

We therefore conclude, and recommend to the AER for its consideration, that EnergyAustralia’s proposed opex in the next period should be as shown in the bottom line of the “bottom-up” analysis table above (the first of the two tables) – that is, totalling $2,740 m over the next period compared with the total of $2,633 m recommended in our Final Report.

9 Independence

Wilson Cook & Co Limited and its reviewers are all independent of EnergyAustralia and the AER, other than in the context of providing the AER with professional advice on expenditure matters from time to time.

Whilst the AER’s staff provided the requisite data for this review and whilst our findings were discussed with the AER on the conclusion of our draft report, we are satisfied that the comments made by the AER have not influenced our opinion improperly but served only to ensure that it addressed the issues sufficiently fully for its purposes.

10 Conditions Accompanying Our Opinion

Assessment Not an Assessment of Condition, Safety or Risk

Notwithstanding any other statements in this review, this review is not intended to be and does not purport to be an assessment of the condition, safety or risk of or associated with the DNSP’s assets and nothing in this report shall be taken to convey any such undertaking on our part to any party whatsoever.

Final Report Remains Unchanged

For the avoidance of doubt, we confirm that the opinions expressed in our Final Report to the AER remain unchanged unless specifically modified in this review.

Disclosure

Wilson Cook & Co Limited has prepared this report in accordance with the instructions of its client on the basis that all data and information that may affect its conclusions have been made available to it. No responsibility is accepted if full disclosure has not been made. No responsibility is accepted for any consequential error or defect in our conclusions resulting from any error, omission or inaccuracy in the data or information supplied directly or indirectly.

Disclaimer

This report has been prepared solely for our client, the Australian Energy Regulator (AER), for the stated purpose. Wilson Cook & Co Limited, its officers, agents, subcontractors and their staff owe no duty of care and accept no liability to any other party, make no representation or warranty as to the accuracy or completeness of the information or opinions set out in the letter to any person other than to its client including any errors or omissions howsoever caused, and do not accept any liability to any party if this report is used for other than its stated purpose.

Non-Publication

With the exception of its publication by the AER, in relation to its review of the DNSPs' expenditure proposals, neither the whole nor any part of this report may be included in any published document, circular or statement or published in any way without our prior written approval of the form and context in which it may appear.

Yours faithfully

Wilson Cook & Co Limited