GEOFF BROWN & ASSOCIATES LTD

REVIEW OF EXPENDITURE GOVERNANCE

WESTERN POWER

Prepared for

ECONOMIC REGULATION AUTHORITY

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SECTIONS

1. INTRODUCTION

The Economic Regulation Authority (Authority) is in the process of reviewing Western Power's proposed revised access arrangement for the regulatory period from 1 July 2009 to 30 June 2012 (AA2). The access arrangement details the terms and conditions, including prices, which apply to parties seeking to use Western Power's regulated south west interconnect network (SWIN). The network is regulated under the *Electricity Networks Access Code 2004* (Code), which outlines a framework for the preparation, approval and review of the access arrangement. The Authority approved Western Power's existing access arrangement for the SWIN in April 2007, which became effective from 1 July 2007.

Under the Code, Western Power is required to periodically submit proposed revisions to its access arrangement and submitted its proposed revisions to the Authority on 1 October 2008 to apply from 1 July 2009 (Proposed Revisions). The Authority is currently in the process of reviewing Western Power's submission..

Western Power is required by the Code to carry out its functions as a service provider in accordance with good electricity industry practice. As part of this review the Authority has engaged Geoff Brown and Associates to undertake a review of a cross-section of representative projects and programs to assess:

- the integration and consistency of procedures and policies across projects;
- the adequacy of internal control structures or specific internal controls, to ensure due regard for effectiveness and efficiency;
- the extent to which activities have been effective in achieving organisational objectives;
- whether projects take place on a timely basis, with minimum network disruption and at least cost;
- the effectiveness of internal audit processes;
- past and current practices relating to planning future work programs and strategies; and
- long term network development strategies.

This report presents the results of the review.

The primary purpose of the review was to assist the Authority understand the extent to which it can rely on Western Power's governance arrangements to determine whether Western Power's access arrangement forward work program and forecasts of capital and operating expenditure are prudent. While this objective as stated is focused on forecast expenditure, the assessment of the effectiveness of Western Power's governance arrangements has, of necessity, required a review of the governance and management of projects and programs[1] undertaken during the current regulatory period from 1 July 2006 to 30 June 2009 (AA1).

Hence this review will also assist the Authority to assess the effectiveness and efficiency of Western Power's capital and operational expenditure over the current regulatory

[1] For the purposes of this review a project is a one-off activity developed to address a specific requirement. Each project is individually managed and requires significant capital expenditure. Programs on the other hand involve the management of expenditure that is incurred on an ongoing basis to achieve desired business outcomes. A program can involve either operational or capital expenditure and is usually managed against a budget allocated in the annual business or work program.

period. This assessment is necessary as capital expenditure in the current regulatory period will, if found to be efficient, determine the opening value at of the regulatory asset base on which Western Power is allowed to earn a return at the beginning of the AA2 regulatory period. An assessment of the efficiency of the operational expenditure over the AA1 regulatory period will also assist the Authority assess the reasonableness of Western Power's forecast of its required operational expenditure going forward.

While it is expected that the outcome of this review will be a significant input into the decisions that the Authority is required to make, it will not be the only input. The Authority is currently progressing other work streams relevant to its access arrangement review and in particular has engaged consultants to review Western Power's expenditure forecasts in some detail. The review discussed in this report is not intended to replicate work being done by others.

2. METHODOLOGY

The review first identified for more detailed examination key business processes that we considered important to the management of capital and operational expenditure. This was informed by a review of documents submitted to the Authority by Western Power in support of its Proposed Revisions). The selected processes were:

Cost Estimation

Cost estimation was included in the review because estimated project and program costs form the internal benchmarks against which the performance of the business is measured. In the absence of external benchmarking, with consistently high cost estimation it would be possible for the business to appear much more efficient than it actually is in reality. The importance of cost estimation to the efficient operation of the business is discussed further in Section 3.1.1, where an engineering analogy is used.

Procurement of Equipment and Materials

Procurement processes were included in the review as the cost of equipment and materials is a substantial component of capital expenditure[2]. Hence efficient procurement processes are necessary if capital expenditure is to be effectively controlled. Very little information on Western Power's procurement processes was provided in support of the Proposed Revisions.

Program Management

Maintenance and minor capital works are generally managed through programs rather than projects. This issue was included in the review because information submitted in support of the Proposed Revisions indicated significant backlogs. In addition, the Office of Energy Safety is applying strong pressure on Western Power to improve its maintenance practices in areas where public and employee safety are perceived to be at risk. Anecdotal evidence provided to the Authority also indicated that this was an area where efficiency improvements could be possible.

Development of Information Technology to Support Program Management

This is closely related to effective program management, which as discussed above, was potentially of concern. Further, information provided to the Authority in support of the Proposed Revisions indicated that Western Power recognised the need for improving its program management processes but appeared to be struggling with the development of systems to support this improvement. The indication was that this was due, at least in part, to a lack of input and commitment from senior management.

One Step Ahead Program

This program was included in the review because it had the specific objective of improving operational efficiency and was frequently referred to in information provided to the Authority in support of the Proposed Revisions. It comprised a series of subprograms over a wide spectrum, ranging from organisation design and business process improvement through to very specific engineering related research. It was not obvious how the different subprograms were selected and how they were linked to a common program strategy or objective. Information provided in support of the Proposed Revisions also indicated that the expected efficiencies from the program were not achieved to the extent envisaged when the program was formulated.

[2] Materials costs also have an impact on operational expenditure but this is less significant.

Budgetary Control of Major Projects

This was included in this review because of its close linkage to the review objectives as established by the Authority. There was also evidence of significant cost overruns on some large projects.

Zone Substation Planning Criteria

As noted in Section 1, long term network development strategies were specifically identified by the Authority as a focus for this review. It was noted that a high proportion of forecast capital expenditure forming the basis for the Proposed Revisions was related to the construction of new zone substations or the upgrading of existing ones. This appeared to be driven by a reduction of the NCR planning criteria from 90% to 75%, but at the time this review was formulated little detail had been provided on what this meant or why the change was necessary.

The review involved a detailed examination of the formal business processes put in place to control each of the above activities. This examination was supported by a review of a number of selected projects and programs to determine how effectively these had been managed. While this review was largely focused on the application of the above processes to the management of the selected projects and programs it was not restricted to these areas and embraced all processes that might lead to successful project and program outcomes.

The specific projects selected for review were:

- the mid-western (Pinjar to Moonyoonooka) 330 kV transmission augmentation;
- supply to the Boddington gold mine expansion;
- the 132 kV Pinjar to Wanneroo transmission line;
- stringing the second circuit of the Shotts-Kemmerton 330 kV transmission line;
- vegetation management;
- replacement of distribution poles and distribution transformers;
- Waikiki substation feeders; and
- routine asset inspections.

In order to obtain documentation relevant to the review, Western Power was initially asked to provide copies of relevant documentation. Geoff Brown and Associates then visited Western Power in Perth where detailed presentations were made on the different processes and programs on 15-17 April 2009. At these presentations Western Power was asked to provide additional written documentation. The findings and conclusions in this report are based on the information provided during the presentations and a review of the supporting information.

3. BUSINESS PROCESSES

3.1 COST ESTIMATION

3.1.1 Introduction

In order to understand the importance of cost estimation to expenditure control, the similarities between controlling a business process and controlling an engineering process could be considered. In an engineering process control system the output of the system (or in analysis terminology the process variable) is continually monitored and when a deviation from the desired output or "set point" is detected an adjustment is made in order to bring the output back to the desired level. Fundamental to effective control is the ability to determine an appropriate set point, the ability to measure the difference between the actual and set point output, and the ability to close the control loop so that corrective adjustments are made in order to correct for these errors.

For an expenditure management process, cost is the key process variable. The cost budget is therefore the set point and when variances are detected between the actual and budgeted cost an adjustment is necessary to correct for the "error". However, a key difference between an engineering process and a business process such as expenditure management is that, whereas an engineering process is largely deterministic, a business process can be significantly impacted by unpredictable stochastic variables. This makes the business process more difficult to control. The impact of stochastic variables is particularly significant in the process of expenditure management within the electric power transmission and distribution industry due to high asset costs, complex engineering requirements, long lead times and high community and political impacts.

The complexity of the process means that accurate cost estimates are critical if optimal and efficient expenditure outcomes are to be achieved. Inaccurate cost estimates can have two highly undesirable impacts.

- They can result in a suboptimal process set point which could in turn result in inefficient outcomes even if the process is otherwise well managed.

- They can also result in large differences between actual and set process outputs which in turn make the process more difficult to control.

As noted in Section 2 above, cost estimation was included in this review specifically because of this criticality to effective business management and governance.

3.1.2 Cost Estimating Processes

Following disaggregation, and after the Authority made its decision on the AA1 access arrangement, Western Power's management and Board recognised that poor internal cost estimating processes were one factor that was inhibiting its business performance. Western Power therefore engaged Tellis Chase to compare its approach to cost estimation with best business practice. The Tellis Chase final report, issued in September 2007, found that there was a lot of effort expended within Western Power on cost estimating and that there were pockets of good intentions and evolving practices. However, cost estimating in Western Power, when reviewed against good estimating practices, was without structure, discipline and leadership. In particular:

- there was insufficient rigour and coordination to bring together all the elements required for an accurate cost estimate;

- there was no in-house process owner for maintaining the tools, techniques and methodology for best practice estimating;

- estimates were based on out of date costs;
- there was a lack of scientific tools for risk analysis and escalation;
- project scopes were not accurately defined for an estimate;
- the functionality of available IT systems was underutilised; and
- there was also a lack of forecasting tools.

At the time of the Tellis Chase investigation, Western Power already had in place its current process for project development, which incorporates three project estimates with increasing levels of accuracy. Essentially “A0” is an initial planning estimate, “A1” is a budget estimate and “A2” is used for the approval of a business case. Tellis Chase commented that:

- Western Power treated A0 estimates with disdain and this rendered the accuracy of estimates in outlying years as useless;
- the estimating function was spread throughout Western Power. There was no process owner to provide leadership of the complete function. When estimates v actuals were wrong, construction blamed the estimate (design) and design blamed construction;
- some estimates were “years old” and therefore did not reflect the costs required to complete the scope, resulting in costly overruns;
- estimates were prepared using internal labour rates even when it was known the work may be given to external parties;
- there were no tools to report and analyse the portfolio of estimates;
- when contingency was estimated it appeared to be a blanket allowance of between 10% and 30%, which the regulator (with good reason) did not accept;
- internal overheads and staff effort were not estimated and it was not clear how regional factors were incorporated into an estimate;
- feedback on estimates was essential to improve accuracy of future estimates, but the progress of estimates from the highest level to the most detail (A0, A1, A2) and the actual costs were not being tracked, and costs in templates and cost units were not being updated; and
- site details important to the accuracy of an estimate were not captured in the budget estimate (A1) and sometimes not even in the business case estimate (A2);

Tellis Chase made ten recommendations to improve Western Power’s estimating process. These were:

- implement an estimating methodology which was complete for all estimation types (A0, A1, A2) and provided a consistent and disciplined approach across the business;
- develop standard criteria to define when a site inspection is required for an estimate. The criteria should be based on a combination of risk, complexity and value;

- immediately conduct a user requirements specification and decide the IT system(s) to be used for estimating. This would allow reporting of components of an estimate across the entire portfolio of estimates and existing projects;

- apply an asset risk score to work orders and each month forecast out 12 months to assist schedulers to meet the current financial year's budget by adjusting the timing of lower risk work;

- apply scientific risk analysis techniques to model the potential impact of cost uncertainties on a project and the likelihood of the cost uncertainties occurring;

- appoint a full-time process owner to act as a change agent to implement the recommendations, provide leadership for the development of excellence in estimating and to provide single point accountability for estimating tools, techniques and training;

- provide support to the process owner from a small permanent team (2-6 persons) with specific skills;

- identify all personnel involved in estimating throughout WP to create a "community of estimators";

- until the estimating system and processes provide accurate estimates that can be used for a regulatory submission, WP should form a dedicated team to prepare estimates for the next regulatory submission using the estimating techniques recommended in this report; and

- embed continuous improvement in the estimating process.

Western Power has largely accepted the Tellis Chase recommendations and the process of implementing them is well underway. In particular:

- an Estimating Centre has been formed and a full time Estimating Manager appointed. This Estimating Centre has about 12 staff, which is larger than recommended by Tellis Chase;

- an Estimating Manual has been prepared. We have reviewed this and note that it incorporates best practice estimating as described in the Tellis Chase report. However at the time of our review we estimated the manual was only about 80% complete. An audit to establish how well the estimating processes described in the manual are embedded in Western Power's current business practices was outside the scope of this review;

- a community of estimators has been formed;

- IT systems for estimating, including Success Estimator and @Risk have been purchased and are being used;

- the inclusion of blanket contingencies in project estimates is being replaced by more sophisticated risk analysis. First a base case estimate is prepared. Project risks are then individually identified and the probability of each risk occurring and its potential impacts on project costs quantified. Monte-Carlo simulations are then used to produce a cost-probability curve for the project. The single point cost used for reporting and project development purposes is the cost on this curve that has a 20% probability of being exceeded;

- A1 and A2 project estimates include the costs associated with the probable project delivery mechanism. A2 estimates for projects to be delivered by alliance partners are prepared by the alliance partnership but are subject to independent review by the Estimating Centre;

- locality factors taken from the Rawlinsons Handbook are applied;

- a dedicated team under the direction of the Estimating Manager was used to develop the estimates used as the basis for the Proposed Revisions. The approach applied generally incorporated the best principles described by Tellis Chase. A significant difference from the approach described above was the use of the 50% probability of exceedence point on the cost-probability curve and the application of a global risk factor. This is described by Evans & Peck[3].

- Western Power is in the process of implementing a project/program management process that will require any cost estimate in an active project under development to be "refreshed" before it is actually used, if the estimate is more than six months old.

Furthermore the treatment of overheads has been formalised both in the estimation and management of expenditure. A 15% margin is now applied to all direct costs and expenditures to collocate corporate overheads. This allocation process, termed "cost driver simple" by Western Power, is intended to allocate overheads across all expenditure, irrespective of whether it is incurred internally or through the use of outsourced contractors. The 15% margin has been determined by Western Power's Finance Division.

3.1.3 Conclusions

It appears from the Tellis Chase report that prior to the end of 2007 there was little internal control over the quality of the cost estimates used for project and program management. Estimating was left to the department concerned and standard of estimates produced was variable. Actual project cost outcomes were not formally fed back into the estimating process and raw costs (particularly equipment procurement costs) were not always updated. Internally there was very little confidence in the A0 cost estimates used for budgeting and planning purposes. While A1 and A2 cost estimates were generally considered more accurate, they were still not adequate for the effective control of expenditure, particularly where there was a long time lag between a project estimate and subsequent project implementation.

The Tellis Chase report has triggered a fundamental change in Western Power's approach to cost estimating. The processes recommended by Tellis Chase were first applied to the preparation of cost estimates for the Proposed Revisions and we surmise that this was due to concerns that there was a high risk of costs being omitted from A0 cost estimates if the old estimating process was used. While historically this problem was often obscured through the inclusion of high contingency allowances, there was a perceived risk that the Authority would disallow some or all of any contingency provision, leaving Western Power underfunded for the AA2 regulatory period. This was apparent from the Evans and Peck report.

It appears to us that, due to the initial focus on developing the forecasts for the Proposed Revisions, Western Power has been slow to incorporate the changes in estimating processes recommended by Tellis Chase into its routine business operations. For example, the New Facilities Investment Test (NFIT) application for the upgraded Medical Centre zone substation used an inflated A0 estimate, which included contingencies and which used inflation factors that appeared high and that were not substantiated in any

[3] Evans & Peck, *Western Power 2009/10-2011/12 Regulatory Reset. Quantitative Risk Assessment of CAPEX and OPEX Expenditures*. May 2008. (WP DMS# 4783411).

way[4]. This application was submitted to the Authority in August 2008 and should in our view have used an A2 or recent A1 estimate.

Notwithstanding this, on the basis of the information provided for this review and our discussions with Western Power staff in April 2009, we are satisfied that Western Power has accepted most, if not all, of the Tellis Chase recommendations and is currently in the process of developing and bedding in estimating procedures based on this report. Should this change process be successful, and we have seen no evidence to indicate that it won't be, we are confident that Western Power's cost estimating processes will be commensurate with industry best practice and will lead to significant improvements in expenditure management and control.

3.2 MATERIALS AND EQUIPMENT PROCUREMENT

3.2.1 Introduction

Materials and equipment can comprise up to 70% of the total cost of primary assets on power transmission and distribution systems. Hence managing the costs of materials and equipment purchased from external vendors is an important component of expenditure management. Industry best practice is to consider not just the initial purchase cost, but the total cost over the life of the equipment, measured in present value terms. This means that it may not always be appropriate to purchase the equipment with the lowest initial capital cost.

Western Power did not provide a formal presentation on its materials and equipment policies and processes. However, at our request, a less formal discussion with staff was arranged and documents were subsequently provided for review as agreed at these discussions.

3.2.2 Discussion

Western Power has a centralised procurement section that is part of the Group Commercial Branch within the Finance Division[5]. The procurement section has the sole authority to purchase on behalf of Western Power, to enter into new arrangements and to renew existing contracts. This authority may be delegated back to business units for particular supply categories or commodities for reasons of practicality, economy or expediency. Such delegation must be formally signed off and reviewed every year.

The procurement section operates under a formal documented procurement policy, which has probity, value for money and transparency as key principles. Approval for all procurement must be obtained in line with formal delegated authority. Sitting alongside the procurement policy is a set of commercial principles that guide business decisions that commit Western Power to spending money.

These principles include:

- developing contracting strategies that meet Western Power's requirements and deliver value for money across the organisation on a total cost of ownership basis;
- ensuring all contract arrangements reflect procurement best practice;
- engaging with subject matter experts to develop the contract strategy from the very first day the customer need has been identified;

[4] Geoff Brown & Associates Ltd, *New Facilities Investment Test, Medical Centre Substation.* Letter to the Authority dated 18 February 2009, paras 2-3.

[5] Western Power is segregated into Divisions, with each division headed by a General Manager. Each Division is further segregated into Branches, headed by Branch Managers.

- adopting a centre-led procurement model;
- adopting standard industry specifications wherever possible;
- fostering the appropriate supplier relationships that deliver value for money;
- applying competitive processes wherever possible;
- developing transparency across all key commercial processes; and
- ensuring Western Power's terms and conditions prevail as the basis for all contracts.

Western Power purchases materials and equipment using a range of contract arrangements. These include:

Strategic Alliances:

Strategic alliance arrangements are considered for suppliers of materials and equipment such as street light luminaires, cables and distribution transformers where equipment is required in large numbers and consequently total costs to Western Power are high. The contract arrangement requires a collaborative relationship between Western Power and the supplier and is based on an open book philosophy. It appears that unit prices are set in advance for each financial year based on expected variable and fixed costs to meet the requirements under the contract and provide the alliance partner with "protected" earnings before interest and taxes (EBIT). Actual costs and revenues are reviewed at the end of each review period and the actual EBIT is calculated. Should the alliance partner's actual EBIT be higher than the protected EBIT, Western Power is entitled to a gain share adjustment equal to an agreed percentage of the difference. On the other hand should the actual EBIT be lower than the protected level, the alliance partner will be reimbursed to fully make up the shortfall.

Alliance arrangements were likely to have been beneficial to Western Power during the booming AA1 regulatory period because the open book philosophy should limit the ability of the alliance partner to make excessive profits at a time of high demand. The cooperative nature of the arrangement should also have allowed Western Power to secure timely supply while at the same time minimising inventory levels. Conversely, in times of economic recession, alliance arrangements could favour the alliance partner due to the protected EBIT.

Period Contracts

Period contracts are favoured for higher cost items such as power transformers where there is an ongoing requirement over the contract period. Under this arrangement contract terms and conditions are agreed before the period contract commences and orders are placed against the contract as and when equipment is required. A period contract is usually characterised by Western Power agreeing to purchase a specified quantity (which usually has a minimum and a maximum) over the contract period. The price of any particular order is determined in accordance with an agreed pricing formula, which is written into the contract.

The use of period contracts is well established in the industry and is more common than a strategic alliance. As period contracts are awarded following a competitive tender process, there is a downward pressure on pricing that is unlikely to be eroded over the period of the contract due to the existence of a predetermined price escalation formula. The major advantage to Western Power is a reduction in the procurement effort since major equipment can be purchased on order without the need to go through a full competitive tendering process.

Preferred Vendor Arrangements

Preferred vendor arrangements are similar to period contracts except that no quantities are specified and Western Power has no obligation to purchase. They tend to be used for the purchase of lower cost equipment items where significant numbers are likely to be required, but actual quantities cannot be forecast with a high level of certainly. Western Power provided for our review a tender recommendation for signing a preferred vendor arrangement for the procurement of distribution equipment. In this case a tender was issued to six potential vendors, of whom only three submitted a proposal. Two of the received proposals were considered non-compliant. Contract negotiations were held with the one compliant vendor and as a result of these negotiations the tendered price was reduced by 5%. The term of the agreement was for an initial two year period with a renewal option for up to a further three years. The unit price over the initial term was fixed and while there appeared to be no price escalation clause to fix prices beyond that, Western Power was under no obligation to extend the agreement beyond this initial term.

The tender evaluation process appeared thorough. The recommendation stated that Western Power's General Counsel provided advice throughout the tender process and performed a legal review on the final executable contract. There was also an independent probity audit. However we are concerned that, even though these ring main units are standard inventory items and are commonly used in electricity distribution networks in Australia and internationally, only one vendor of six invited to bid was willing to comply with Western Power's requirements. It is not clear whether this was because the economic boom at the time of tendering was fully utilising the available production capacity or whether Western Power's technical requirements exceeded industry norms.

Western Power's pre-tender processes are thorough. While procurement is centralised and undertaken by specialists, there is early consultation with the relevant operating branches within the business. For large contracts this process culminates with the preparation of a strategic planning document that recommends the contracting and procurement process that is expected to provide the best commercial outcomes for Western Power. The tender process itself seems thorough and includes a strong emphasis on probity and integrity.

3.2.3 Conclusion

Western Power's tendering processes appear thorough and robust. We would have expected no less of an organisation that has historically been required to comply with government purchasing rules. While such compliance does not appear to be a formal requirement of the Electricity Corporations Act 2005, under Section 32 of this Act Western Power is still required to report to the Commissioner for Public Sector Standards, and under Section 68 of the Act Western Power must obtain ministerial approval before entering into contracts with a total value of more than $20 million.

Our one reservation arises from a perception that Western Power may sometimes specify requirements over and above industry standards and norms. This could increase procurement costs because manufacturers would need to supply purpose built, rather than off the shelf, equipment. While we have no direct evidence of this occurring, and while the use of industry standard specifications is one of Western Power's commercial principles, we have seen nothing in Western Power's procurement processes that would appear to mitigate this risk.

3.3 ONE STEP AHEAD

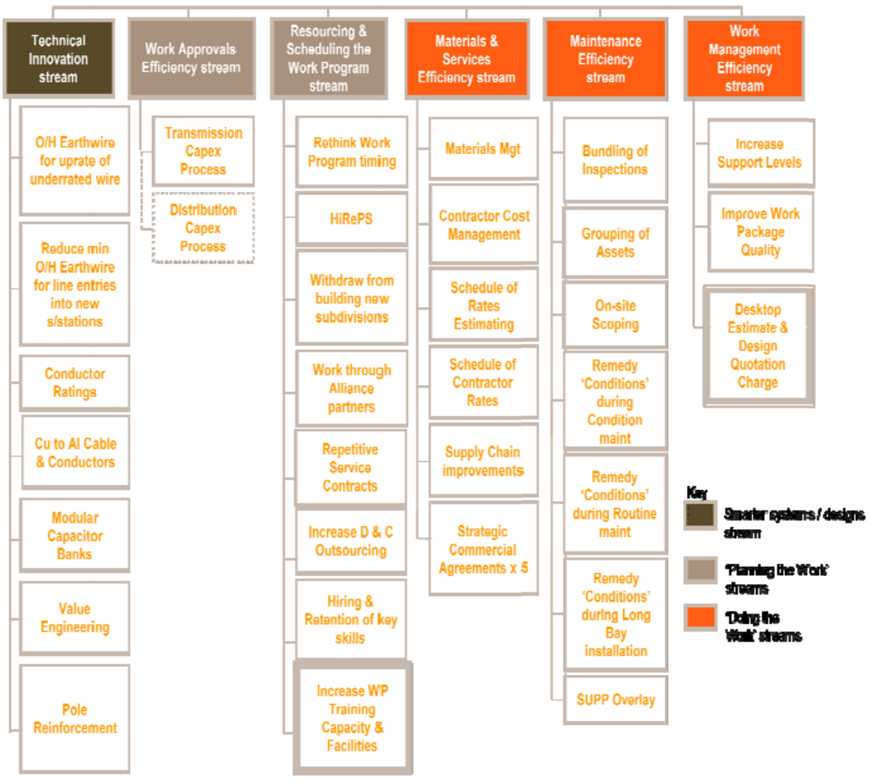
3.3.1 Introduction

The One Step Ahead (OSA) program was conceived with the assistance of strategic business consultants Marchment Hill Consulting in March 2005 to prepare the networks business unit of the then aggregated Western Power for disaggregation in April 2006. At the end of 2005 Port Jackson and Partners of Sydney were called in by the Board to undertake and independent assessment and validate the work being done by Marchment Hill.

According to Western Power's OSA close-out report[6], two program "themes" emerged. The first was concerned with the creation of the structure, functions and infrastructure for the new organisation. The second theme, which is the subject of this review, was concerned with business improvements in areas considered necessary for effective operations and to establish the new Western Power on a solid footing. Projects were identified by internal staff and presented in a series of business cases over several months to a steering committee consisting of the networks business unit management team. Consultants from Port Jackson Partners led most of this work supported by internal staff with expertise in the relevant areas of business.

The business cases covered a range of issues including strategies to obtain sufficient resources to deliver the work program, systems for planning and tracking work, capital approvals processes standardisation and labour and materials efficiency. The program as it finally evolved is shown in Figure 1 below.

Figure 1: Structure of the One Step Ahead Program



The consultants estimated the efficiency benefits of the program would be between $95 million and $105 million.

3.3.2 Contractor Cost Management

In order to assess the impact and effectiveness of this program we examined documents relating to the contractor cost management project. This project was selected primarily because it was considered particularly relevant to the Authority's objectives in commissioning this review.

6 Western Power DMS# 4012722

The business case for this project is dated July 2006. At that time there was limited control over contractor charges for internally funded capital expenditure on the distribution network. It was considered that loose contractual arrangements, combined with limited purchase order, quote and invoice reconciliation, was resulting in Western Power incurring significant overcharges.

In order to quantify the extent of this overcharging a sample of 40 jobs was selected from contractor invoices in February and March 2006 for capital works on the distribution network. Relevant documentation was extracted relating to the work covered by these invoices and the required resource inputs for each job were assessed by experienced project managers. The assessment took into account scope changes and site or logistics problems that could result in longer hours than would otherwise be expected.

The study found there were three large contractors, representing 40% of the total contractor spend, that were overcharging Western Power. In two cases the level of overcharging exceeded 70%. These sampled results were then extrapolated to assess their impact on the internally funded capital expenditure in the 2004/05 year. This found that:

- the total internally funded distribution capital expenditure in the 2004/05 financial year was $71.30 million;

- of this, $14.60 million was undertaken by outsourced contractors;

- $6.00 million was undertaken by the three contractors that were subsequently found to be overcharging;

- if the level of overcharging found during the sampling process had occurred during the 2004/05 year the total excess expenditure was $2.45 million. This represented almost 3.5% of Western Power's internally funded capital expenditure on the overhead distribution network and almost 17% of the total contractor expenditure.

The analysis found that the primary driver of the overcharging was contractors assigning more workers than necessary to a particular job. Other behaviours causing contractor overcharges were:

- contractors were slow;

- hours for vehicle drivers were particularly high; and

- contractors resourced jobs with trainees and other inadequately skilled staff who took significantly longer to complete the work.

Cases were also found where invoices were duplicated and paid twice.

The business case estimated that if the results of this analysis were extended to include all contractor distribution capital expenditure, there was potential to generate a further $1.72 million in reduced costs and noted that OSA business cases prepared for other works had identified similar levels of contractor overcharging.

It appears that this situation arose because Western Power was routinely paying contractor invoices, with the only check for accuracy being to confirm that the work invoiced had actually been done. The business case recommended that contractor audits be instituted that would:

- check all purchase orders against current contractual arrangements:

- check all purchase orders against contractor quotes;

- implement a standard requirement for a quote to be obtained for every job before it was authorised; and

- check a contractor invoice against the relevant quote.

Other recommendations included a general tightening up of contractual arrangements and in particular the development of a standard schedule of contractor rates. It was estimated that the proposed contractor auditing process would require the employment of two new full time equivalent staff and the business case recommended that every purchase order, quote and invoice be reconciled for the first six months to drive the required behaviours, but after this time the audit process be transitioned to representative sample checks.

The project was formally closed out of the OSA program with the issue of a Handover Report dated 31 July 2007[7]. The report states that the work on the project highlighted a number of other issues that impacted on the management of contractor cost. The implication was that this made the issue difficult to manage in the context of a specific project and this in turn impacted on the success of the project.

Extracts from the holdover report are quoted below.

> *The project was originally known as "Contractor Management on the Distribution Overhead Network" and later renamed as "Contractor Management" followed by "Field Services Construction Cost Management". Due to conflicting views between Commercial and Field Services (at the time) the scope of the project was redefined in September 2006 to exclude the review of any current contractual agreements or related inputs (e.g. estimates). Work on the project therefore proceeded with focus on internal process controls that could be implemented by Field Services on the understanding that any commercial issues arising would be conveyed and ultimately resolved by the Commercial Branch where appropriate.*
>
> *Whilst the high level project deliverables were attained to some degree … it became clear as the project progressed that many more issues were impacting the management of contractor costs. Every effort was made to address these issues. However, most were considered to be outside of the scope of the project whilst others were the subject of additional issues (e.g. works engine confusion, conflicting project priorities and/or resource constraints).*
>
> *…Whilst it's clear that the Field Engineering and Works Branch of the Service Delivery Division has been particularly proactive in attempting to address governance and contractual/cost issues, its ability to do this from a subjective perspective may be questionable.*
>
> *…It became clear to the project team that a fundamental issue impacting contractor (and general) cost management was unclear ownership for the management of work from a cost and budget perspective. Whilst the Service Delivery Division was clearly responsible for "getting the work done" its responsibility for the achievement of WP's budget outcomes is not clear.*
>
> *The issues have been compounded by a lack of clarity in roles and responsibilities post disaggregation, particularly in relation to certain types of work e.g. Customer Funded and Maintenance work. Currently there is still no project management group that has accountability for the Customer Funded budget or work and the role of Program Delivery (now relocated to the Service Delivery division) in relation to the rest of the Service Delivery Division is not understood by all.*
>
> *Despite the number of issues that could not be resolved within the project scope and timeframe, the project team working in conjunction with other project teams*

[7] Western Power, *FS Construction Cost Management Project, Handover Report.* 31 July 2007.

> *(specifically the Construction Package Improvement Project) and operational resource identified and/or implemented a number of key initiatives that will collectively improve the management of contractor costs.*

The handover report did not attempt to quantify the savings made as a result of the work undertaken on the project, but made a significant number of recommendations for further action. Our review indicates that at least some of these recommendations, such as the recommendations related to estimating, have been or are in the process of being implemented.

The overall OSA Closeout Report, dated October 2007, identified the Contractor Cost Management project as one of the OSA projects where the projected benefits were not achievable.

We think that the findings of the business case in relation to inadequate contractor management and overcharging by contractors should have been taken very seriously by Western Power at the time, even to the extent of calling in auditors. At the very least, immediate action should have been taken to address the specific problem identified in the business case. The handover report did not comment on whether such action was taken and instead focused on addressing the underlying cultural and structural issues that caused the situation to arise.

Leaving that aside, it is important to note that the Handover Report is dated July 2007, almost two years prior to this review. The presentations provided by Western Power for this review indicated a much higher standard of contract management, although specific events identified in Section 5.7 of this report indicate ongoing deficiencies in the way Western Power manages its contractors. Notwithstanding this, we believe that the issues identified in the project business plan have largely been addressed by higher level organisational changes and business improvement initiatives put in place since the issue of the Handover Report. The contracts described in the OSA business plan have now expired and program management has been centralised. The contracts have been replaced by fewer, larger contracts with more professional contractors, many of whom have a national presence throughout Australia. Audit programs have been put in place with up to 10% of the work done by contractors being formally audited. Situations were described during the presentations where action had to be taken because contractors were not performing and in these cases the action taken by Western Power was generally appropriate.

The business case was based on information acquired during February and March 2006, before the start of the AA1 regulatory period. It was dated July 2006, which coincided with the beginning of the regulatory period, and it is reasonable to assume that the overcharging was still occurring at that time. We have seen no evidence to indicate that the issue was decisively addressed in the manner proposed in the business plan, but the extent to which the overcharging persisted through the early part of the regulatory period is unclear. Notwithstanding this, we are confident that current procedures are sufficiently robust to detect and address any contractor overcharging.

3.3.3 Discussion

The OSA Closeout Report, and the presentation given by Western Power for this review, both indicated that the benefits achieved from the different OSA projects were variable. In some cases the benefits are directly identifiable and potentially measureable; for example, as a result of this project Western Power has recently started to use aluminium underground distribution cable instead of the more expensive copper. In other cases the benefits anticipated from a particular project were not realised, but other benefits emerged.

We suspect the some projects did not achieve the benefits anticipated in the business case because the assumptions on which the business case was based proved inaccurate. For example the business case for the Contractor Cost Management project discussed in Section 3.3.2 was predicated on the continuation of decentralised control and did not foresee the centralisation of program management that has now occurred. Nevertheless the findings of the project team, together with the findings of other project teams in the “doing the work” streams are likely to have significantly impacted the shape and evolution of the current business structure and processes.

Western Power has attempted to measure and quantify the benefits of this program with limited success, probably because many of the benefits are speculative and not directly measureable. The OSA Closeout report forecast a total benefit of $57.2 million by 2010. In the presentation for this review Western Power claimed a benefit of $53 million up to March 2008. Furthermore an additional $30 million in benefits have been identified over the period from business improvement programs initiated outside of the formal OSA framework.

We suspect that the greatest benefit of the OSA program is likely to be its impact on the culture of the organisation. The program empowered staff from within the organisation to identify efficiency improvements and provided a vehicle (and funding) for these improvements to be researched and implemented. The OSA Closeout Report states:

> *The original consultant-led approach proved costly in consulting support and raised issues with regard to business ownership and prioritisation of project work versus business as usual and Division projects. Western Power appointed a Program Director (GM Business Transformation) and adopted a program management approach. Each initiative was established as a separate project with a Project Manager and General Manager Sponsor. The project reporting and steering committee structures, which had proved cumbersome, were streamlined and refined. Considerable savings on consultants were achieved.*

It is a credit to Western Power staff that the initiative did not die following the loss of external consultant support. The current organisational structure includes an “Enterprise Solutions Partner” who oversees a section dedicated to business improvement, based on the Lean Six Sigma approach to achieving operational excellence. It is not within the scope of this review to critique or evaluate this business improvement initiative but it is relevant to note that the focus on efficiency and business improvement, which had its genesis in the OSA program, is still strong in Western Power.

3.4 WORKS PROGRAM MANAGEMENT

3.4.1 Works Program Governance

Western Power’s works expenditure budgets are enshrined in its Works Program. The Works Program is a list of projects and programs that Western Power may implement over the next 25 years together with their estimated costs. The Works Program is subdivided into three components.

Unconstrained Works Program

The Unconstrained Works Program is essentially a “wish list” of projects that staff within Western Power would like to undertake within the next 25 years. To be included in the Unconstrained Works Program a project must be defined and justified in broad terms, a planning cost estimate must be available, an indicative required in service date provided and the project must be approved. Authority to approve a project or program inclusion in the Unconstrained Works Program extends to relatively low levels within the organisation and such inclusion does not imply a commitment by Western Power to proceed.

Proposed Works Program

The Proposed Works Program is a ten-year subset of the Unconstrained Works Program selected on the basis of priority and capacity to deliver. Planning documents, such as the

Network Investment Strategy, the Asset Risk Management Framework, the Asset Management Plan and other asset strategy documents, form inputs to the process of prioritising projects in the Unconstrained Works Program for inclusion in the Proposed Works Program. This assessment, which is completed in July each year, involves ensuring that only higher priority work is included in the proposed work program, and that the forecast total annual cost of this work matches expected funding availability. We have not seen detailed procedures for this process, but we understand that it is undertaken at a management level without board involvement. This is appropriate given that the process is essentially one of work prioritisation, that the Proposed Work Program does not commit expenditure and that it is updated annually as work priorities and funding availability become clearer.

Approved Works Program

Prior to each new regulatory cycle the Board approves a works program that forms the basis for the submission to the regulator to support the proposed revisions to the current access arrangement. Once the regulator approves the new access arrangement this works program becomes the Approved Works Program. Between regulatory submissions the approved works program is reset annually. Western Power seeks input from sponsors on project risk and priorities, resource constraints and from the Finance Division on financial constraints. Customer Services Division has responsibility for updating the Approved Work Program. Once a draft updated program is complete it is submitted to the Program Performance Committee for feasibility endorsement and then to the Works Program Committee for endorsement and submission to the Board for approval.

The Program Performance Committee is a committee comprised of Branch Managers that has been established to:

- ensure that the Approved Works Program is implemented in accordance with established budgets and the Strategic Development Plan;
- consider requests for changes to projects in accordance with the change control procedure; and
- provide recommendations and advice to the Works Program Committee on the implementation of the Approved Works Program.

The Works Program Committee comprises General Managers and is therefore a subcommittee of the Executive that has been established to:

- ensure the alignment of the Approved Works Program to the Western Power strategic development plan and to its customer obligations; and
- provide strategic direction for work program establishment and delivery.

The Board approves the total budget for the Approved Works Program and also approves larger programs and projects in accordance with its approved delegated authorities before they are approved for construction or implementation.

The development and ongoing management of the Approved Works Program is essentially a high level process that ensures Western Power operates within its approved budgets and that projects and programs are appropriately prioritised. Inclusion of a project or program in the Approved Works Program does not imply formal approval to proceed. The project development, approval and implementation process, which is described in Section 3.4.2 below operates under the umbrella of the works program but is not an integral component of the works program development process.

We see two main weaknesses of the works program development process as described above.

Firstly it is not clear that the Approved Works Program should be based around a three-year regulatory period when the environment in which Western Power operates is continually changing. Our understanding of the regulatory regime is that the access arrangement sets a limit on the revenue that Western Power can earn during a regulatory period. The disaggregated expenditure forecast accepted during an access arrangement review is merely a tool that the Authority uses to ensure that the revenue cap it sets is appropriate. We think revenue cap should be treated as a constraint and the disaggregated expenditure forecast on which the revenue cap is based should not necessarily be the primary driver for planning Western Power's operations, particularly in the second and third year of the regulatory period. The risk is that if this disaggregated forecast is considered the primary driver for the management of the work program, then Western Power may be slow to respond to changes in its operating environment. Poor project prioritisation and suboptimal expenditure outcomes could occur as a result. We believe Western Power now recognises this as we understand that during the AA2 regulatory period the Approved Works Program will be updated annually on a rolling three-year basis.

Secondly, there is a misalignment between the three year planning period for the Approved Works Program and the rolling five-year horizon of the government budgetary planning process. We think governance will be improved if the two planning horizons were aligned and this would be achieved if the Approved Works Program had a five year horizon. An alternative approach would be to shorten the planning horizons of the Approved and Proposed Works Programs to one and five years respectively and to tighten the criteria for inclusion of projects and programs in the Proposed Works Program.

3.4.2 Project Development and Implementation

Western Power currently uses a three gate approval framework for the development of projects to the point where expenditure is committed and the project is passed to the Service Delivery Division for implementation. These are described below.

Project Creation

The project creation phase involves preliminary project definition. It involves determining the purpose and timeframe of the project and developing the most probable project option to the stage where a preliminary (A0) estimate of likely project cost can be prepared. After preliminary approval, the project is placed in the unconstrained works program. Approval to create a project is generally given at a relatively low management since it does not imply a commitment of funds or a firm intention to proceed with the work.

Approval in Principle

Approval in principle requires the evaluation of a range of alternatives and the selection of a preferred option. It also requires the project to be subjected to prioritisation and risk assessments. In theory the design of the preferred option and the project delivery strategy should be developed to the stage where an A1 (+/-20% accuracy) cost estimate can be prepared, but historically this has not always occurred. By the time a project is approved in principle it would have been elevated from the Unconstrained Works Program to the Proposed or Approved Work Program, depending on its required in service date. Projects in the Approved Works Program are subject to a formal change control process, which may need to be invoked as the project is developed.

Business Case Approval

Business case approval requires the selected project option to be further developed to the stage where the expenditure can be committed and the project can be passed to the Service Delivery Division for implementation. This requires the design to be progressed to the stage where an A2 cost estimate (+/-10%) can be developed as the basis for an approved project budget. For larger projects it may require completion of the Regulatory

Test and the NFIT. Preliminary project planning should have progressed to the stage that key milestones have been developed and the expenditure can be allocated across different financial years. The process culminates in the preparation of a formal business case, which must be approved in accordance with Western Power's formal delegation policy before expenditure on the project can occur.

For long lead time projects some preliminary expenditure may be necessary during this phase for the purchase of land, acquisition of easements or the purchase of long lead time items. A preliminary business case is necessary before such expenditure can occur.

Project Implementation

We have briefly reviewed Western Power's current procedures for the management of discreet projects that are not included within a program budget and these appear robust. Once business case approval is given for any project or program a formal change control process is required to manage changes in budget or schedule. The process requires the project or program manager to prepare a change control request that summaries the reason for the change and its implications. The management level at which a specific change control request can be approved is established by the Board's approved schedule of delegated authorities. The Board must approve changes with significant financial implications. Western Power appears to be adhering to this change control process.

Western Power is currently developing a revised process for monitoring project implementation. This will be put in place in June 2009 in time for the start of the AA2 regulatory period.

Key changes include:

- The existing three-gate project development process will be replaced by a six-gate process that extends right through to project completion.
- A Works Program Office will be created to monitor the progress of projects through the different gates of the implementation and delivery process and to provide support to project managers.
- There will be greater use of software, business rules, templates and checklists to ensure a more consistent approach.
- There will be greater emphasis on cost management, risk assessment and quality assurance. For example there will be a new requirement that all estimates over six months old must be refreshed before work proceeds.

3.4.3 Program Management

As noted in Section 2, program management[8] was specifically included in this review because in its access arrangement information supporting the Proposed Revisions Western Power indicated that it was facing significant maintenance backlogs. Furthermore, the Office of Energy Safety has issued a number of reports critical of the safety risk posed by the current state of the network, largely caused by a lack of preventive maintenance.

At the time of disaggregation it appears that programs were primarily undertaken using Western Power's internal field resources supplemented by small local contractors, often former Western Power staff, who tended to be used as an extension of Western Power's

[8] Programs are essentially either load driven or maintenance driven. Load driven programs involve capital expenditure and include the connection of new small customers and the replacement of distribution assets that are under-rated for their expected load. Maintenance driven programs can require either capital or operations expenditure. Maintenance driven capital works involve the replacement of assets on account of their condition; for example, pole replacements. Other maintenance driven programs, such as vegetation management and asset inspection generally require operation expenditure.

own internal work force. To manage this work, Western Power's field services were segmented into five operating cost centres; Transmission, North Country, South Country, Metropolitan and Goldfields. The Transmission cost centre was responsible for the maintenance of all transmission assets in the network while the other divisions were responsible for the distribution network assets in their respective areas. In addition inspection and maintenance of different asset types were the responsibility of individual specialist groups within each operating area. Each division was allocated its own budget and was managed as a separate cost centre.

From the perspective of maintaining the integrity and reliability of the distribution network, this approach had a number of shortfalls, as noted below.

- Asset inspections and routine maintenance (including maintenance driven capital works) were funded from the operating division's budget. Since these works do not have an immediate impact on the availability of supply they tended to have a low priority, which meant the funding and resources were often reallocated to higher priority or more urgent activities;

- The low priority given to this work meant that it was more adversely affected by budget cuts;

- There was often a lack of coordination of maintenance activities amongst the sections responsible for different asset types potentially leading to inefficiencies.

- Maintenance planning tended to be ad-hoc and was likely to be variable across the different operating divisions.

- The process was an open loop in that there was no formal process to ensure that planned inspections and maintenance work was undertaken in a timely manner.

We understand from Western Power that these problems were exacerbated by government budget cuts that persisted for at least a decade prior to disaggregation; a focus by the executive of the former aggregated Western Power on generation at the expense of distribution; and a significant increase in the level of customer driven work as a result of the booming Western Australian economy.

In December 2005, as part of the One Step Ahead program, Western Power established a business case for rationalising the 14 different inspection programs that currently existed into four consolidated programs, which was estimated to result in a potential saving of $3.8 million a year. The most significant rationalisation related to pole inspections, where six different inspection programs were to be rationalised into a single combined inspection program to give an estimated savings of $3.46 million per year. This is discussed in Section 4.7.

The development and implementation of a number of other expenditure programs such as vegetation management and pole replacement are also discussed in detail in Section 4. The evidence from these reviews is that Western Power is significantly improving its program implementation process through the centralisation of program control, the development of specialist program management teams and the outsourcing of work to specialised program contractors.

3.4.4 Conclusion

We think the works program governance processes and the program and project development and implementation procedures that are currently in place are generally robust. These processes and procedures have evolved over the AA1 regulatory period as a result of Board and management initiatives such as OSA and would seem to be much stronger than at the beginning of the regulatory period. A major remaining weakness is in the application of the NFIT and we have seen no procedures or guidelines in respect of when NFIT pre-approval is required or how an application should be prepared. We understand that Western Power now requires major augmentation projects to get pre-approval of the NFIT before a business case is approved, but have seen nothing to indicate that this requirement has been formalised.

In Sections 4 and 5, we identify and discuss weakness in the way specific projects and programs have been developed and implemented, but these issues appear to be related more to the extent to which the processes have been applied in practice, rather than the quality of the processes themselves. It appears that Western Power now recognises that there is room for improvement in the delivery of projects and the new procedures now being developed for implementation by the beginning of the AA2 regulatory period should largely address the problems, provided they are effectively implemented. We remain concerned, however, about Western Power's treatment of NFIT approvals, which do not appear to have been effectively addressed by the changes proposed.

3.5 ZONE SUBSTATION PLANNING CRITERIA

3.5.1 Introduction

In 1996, as a cost saving measure, the Western Power executive decided that zone substations supplying the metropolitan Perth area outside the central business district could be loaded to 90% of the substation normal cyclic rating (90% NCR), which was defined as the sum of the NCR of all transformers at the substation. In the event of a single transformer failure a mobile rapid response substation transformer (RRST) held in reserve for this purpose would be put into service to replace the failed transformer. The time taken to energise the RRST is estimated to be up to 24 hours[9] and over this time customers would be at risk of load shedding.

In the unusually hot summer of 2004, 15 zone substation transformers alarmed on high load with two of these tripping. Furthermore, in July 2004 the Sommerville Inquiry[10] in Queensland recommended that the two Queensland distributors reduce their asset utilisation to a level consistent with good industry practice, which the Inquiry understood to be between 60% and 65%. As a result of these events Western Power commissioned a report from KPMG that compared the 90% NCR substation loading criterion with the loading criteria used by other distribution utilities in Australia. Key conclusions of this report were that:

> *it may be prudent for [Western Power] to adopt a more conservative planning approach than its current NCR planning criterion for all [metropolitan] zone substations.*

and that:

> *[Western Power's] effective planning standard appears to be more aggressive than those of the six utilities we surveyed for metropolitan zone substations.*

As a result of these reports and further internal analysis, Western Power subsequently decided to introduce an NCR wind-back program, which would reduce the maximum metropolitan zone substation loading to 75% of the NCR rating of all substation transformers over a ten year period, at an estimated cost of $21 million per year. It considered that the program would improve reliability by reducing the need for proactive load shedding in the period before the RRST was put in service. Such load shedding would normally be rotated between affected customers to minimise the time over which any one customer would be without supply.

9 Western Power staff indicated that this estimate includes a time contingency and in the absence of unexpected problems the RRST would normally be livened in under twelve hours.

10 *Detailed Report of the Independent Panel, Electricity Distribution and Service Delivery for the 21st Century*, Queensland, July 2004, Darryl Somerville, Chair.

Western Power's Proposed Revisions are based on a forecast total capital expenditure requirement of $246 million over the period for new and upgraded zone substations. This provides for the construction of 14 new substations and upgrading the transformation capacity at 17 existing substations. This expenditure was driven by both a forecast increase in demand and the impact of the NCR wind-back program. As part of this review, the Authority must decide how much of this expenditure is necessary.

3.5.2 Discussion

Western Power's metropolitan zone substation sites normally have sufficient space to accommodate three transformers, and Western Power has standardised on a transformer rating of 20/33 MVA. Individual transformers are not operated in parallel on the low voltage side in order to limit fault levels. There are generally four feeders per transformer and planning standards allow each feeder to be loaded up to 80% capacity under normal operating conditions[11]. The standard distribution voltage is 22 kV, although 11 kV is used in the inner metropolitan area and some older established metropolitan areas still use a 6.6 kV distribution voltage. One implication of this arrangement is that there will be some imbalance in the load across the transformers at a particular substation because they are not operated in parallel. Another implication is that if a substation loses a transformer at times of high load there will generally be an immediate loss of load to customers while the distribution network is reconfigured to accommodate the transformer loss and transfer load to neighbouring substations[12]. A third implication is that Western Power's high feeder loadings limit its ability to transfer loads using the distribution network.

The NCR wind-back program will not eliminate the initial loss of load. However, in most situations it should reduce the time taken to restore load following this initial loss as a reduction in the load at a particular substation will, all else being equal, also reduce the load on the associated distribution network.

Notwithstanding this, there appears to be an inherent assumption in Western Power's rationale that any load shedding that may be necessary before the RRST is put into service would be more disruptive and have a greater impact on supply reliability than the initial loss of load at the time of the fault. We think this assumption is flawed. With an interconnected radial distribution network, it would normally be possible to avoid the need for subsequent load shedding by "shuffling" load across the network, if necessary over a wide area. If neighbouring substations were highly loaded these in turn could be off-loaded to other zone substations to make room for load from the faulted substation. We think that network operators would generally do this rather than move to a load shedding regime and that this approach would be used even with the high metropolitan feeder loads on the Western Power network.

Hence we think it is a misconception to argue that the transformer wind-back program will significantly improve the reliability of supply to customers by mitigating the risk of load shedding. Its most immediate impact will be to reduce (but not eliminate) the, magnitude and duration of the initial load loss following a transformer failure. While this will result in some improvement in reliability, it was not the main objective of the wind-back program as originally formulated.

Our view is that asset utilisation is related, not to the load on specific individual assets, but to the provision of "capacity headroom" to facilitate the management of emergency

11 This means that in the event of a major feeder fault (most typically the loss of the cable taking supply away from the substation) the load would need to be dispersed across at least four other feeders. The high level of loading limits the ability to transfer load through the distribution system and increases fault restoration times because of the additional switching required. Our experience is that feeders in metropolitan areas are more usually loaded to a maximum of about 65% of rating under normal operating conditions, which allows the load to be taken up by two other feeders in the event of a fault. This is consistent with the distribution system utilisations reported in Queensland by the Somerville report.

12 The only exception to this will be in two transformer substations, when the load on the faulted transformer can be fully taken up by the second transformer, or at three transformer substations if the load can be fully taken up by an adjacent transformer. In other instances manual switching within the distribution network will be required before load can be restored.

situations that the network is not designed to handle. This implies that asset utilisation to be meaningful should be averaged across an asset base.

Some capacity headroom is needed because a fault on an individual network element can sometimes escalate into a more serious event as a consequence of one or more unexpected consequential failures. This situation can arise if the management of the initial fault results in another part of the network being loaded to a level above which it normally operates and for which it has not recently been tested. A possible scenario, which was experienced very recently on the Sydney waterfront, is an underground cable being faulted under high load conditions as a result of undetected "dig-in" damage[13]. A consequential fault of this nature can escalate the original outage and such escalating situations are generally easier to contain and manage if unused capacity is available for operators to call on. In Western Power's case, the capacity released by the NCR wind-back program would be of little benefit if the spare capacity could not be accessed because of high distribution network loadings. Hence we see little point in the program unless the substation capacity released is matched by a reduction in the utilisation of the associated distribution network to a similar level. The program as currently formulated makes no reference to reducing the utilisation of the distribution network and we understand that loading distribution feeders to a maximum of 80% capacity remains Western Power's planning criteria[14].

We note also that zone substation transformer failures are rare events, while distribution system faults are relatively common. A reduction in the utilisation of the distribution network will simplify the process of network reconfiguration following a distribution system fault and thus reduce the time taken to restore supply to affected customers. Hence this is likely to result in a more significant improvement to network reliability than the NCR wind-back program alone.

Under the NCR wind-back program the approach taken by Western Power to determining whether a transformer upgrade in any particular year is to linearly reduce the maximum allowed loading of each metropolitan zone substation by 1.5% of its total rated NCR[15]. Action is taken when the forecast load for a particular year exceeds the reassessed rating. If there is spare transformer capacity in a neighbouring substation, the overloaded substation is relieved by means of a load transfer, if the distribution system has sufficient spare capacity. Otherwise an additional transformer or new substation is indicated. Hence program expenditure is driven by the impact of a "smoothed" reduction in substation NCR ratings. This could lead to uneven expenditures in contrast to the business case used to support the program, which indicated that it would be the expenditure rather than the substation ratings that would be "smoothed" in order to drive program design.

3.5.3 Conclusions

We agree with KPMG's conclusion that the asset utilisation within the urban distribution network is higher than what would normally be considered good industry practice and we believe that the asset utilisation should be reduced over time. However, we think the NCR wind-back program on its own will have limited impact on the reliability of supply to customers and that it would be more effective if it were closely integrated with Western Power's program to reduce the utilisation of distribution network feeders[16]. We have seen no indication that these two programs are directly linked, although we accept that this could be the case.

13 This also occurred in Melbourne in 2001. Cable failures as a result of abnormally high loadings following a less serious fault situation also precipitated the 1998 central business district outage in Auckland.

14 If the number of feeders is not increased when distribution transformer capacity is added there will be no impact on distribution network utilisation.

15 This is in line with the program objective of reducing the allowed maximum demand at each substation by 15% over the ten year period of the program.

16 Western Power's AA2 expenditure forecast includes provision for reducing the peak loads on existing distribution feeders. However this program only targets feeders where the peak load is higher than 80% of the feeder rating.

There is also some evidence that, at a higher level, there is a lack of integration between transmission and distribution planning, which are managed by different departments within Western Power[17]. We think power transformer capacity is likely to be better optimised in jurisdictions such as Victoria and New Zealand where the cost of the assets connecting the transmission and distribution networks is borne by distributors, who are therefore required to "buy" power transformer capacity from the transmission network service provider.

While further analysis is necessary before firm conclusions can be reached, it is possible that the high level of substation upgrade expenditure forecast for the AA2 period is that the progressive reduction in the maximum allowable load on individual substations over the period of the program is driving uneven or lumpy expenditure requirements. An alternative approach would be to drive the program on the basis of a smoothed expenditure curve and to target the most heavily loaded substations to the extent that expenditure is available.

We think that Western Power should review the effectiveness of its NCR wind-back program as currently formulated and the extent to which it is achieving its intended outcomes. It should also review its other zone substation and distribution network planning criteria to ensure that the reliability of supply achievable from its existing asset base is maximised and that the use of zone substation assets is optimised. This review could include consideration of whether zone substation planning should be more closely integrated with the planning of the distribution network and whether this planning should be undertaken at an area rather than individual zone substation level.

[17] Zone substations are considered part of the transmission system.

4. PROJECTS AND PROGRAMS

4.1 SUPPLY TO BODDINGTON GOLD MINE

[Text removed as it includes confidential and commercially sensitive information]

4.2 PINJAR-WANNEROO TRANSMISSION LINE

4.2.1 Introduction

The project, as originally formulated, was the construction of a new 25.8 km, 132 kV transmission line between Pinjar power station and the Wanneroo substation. The new line was required initially to prevent a possible widespread power outage in the event of an unplanned fault in a critical line when a second key line was out of service for maintenance. The line was routed past the site of the proposed Neerabup 330 kV terminal station and would be diverted into Neerabup when completed. When this occurred the lines would be used to inject supply from the Neerabup interconnecting transformer into the 132 kV network. To this end the line was constructed as a double circuit line between Wanneroo and the Neerabup site and single circuit for the remainder of the route.

The project was approved by the board of the then aggregated Western Power in early 2005. The business case cost estimate was $22.1 million including escalation and contingencies and the required in service date was November 2006, in time for the 2007 summer. The line was eventually put into service in November 2008 at a cost of $32.8 million.

4.2.2 Project Justification

Western Power's transmission planning criteria has two main requirements that trigger the augmentation of 132 kV transmission lines. These are:

- the system must be able to withstand the unplanned loss of any transmission line at times of peak demand without loss of load assuming all other lines are in service. This is the standard N-1 security criteria;

- in addition, at times when the network demand is less than 80% of the forecast peak the system must be able to withstand the unplanned loss of a transmission line assuming that another line is out of service for maintenance and that generation has been rescheduled to allow for the maintenance outage.

The above planning criteria are reasonable and generally consistent with the criteria used in other jurisdictions. We have reviewed Western Power's planning study for the north Perth area that identified the need for the study. This study identified that the second of the above criteria would not be met for the forecast peak demand in summer 2007 unless the 132 kV transmission line was reinforced.

We have a minor concern regarding the load forecast used in the planning study. It appears the load forecast was prepared by determining the average growth rate over the previous ten years and then extrapolating the actual load experience in 2004 by this growth rate. This methodology, while crude, is often used since it has been found to work as well as more sophisticated methods, given the inherent uncertainties in predicting future demand. However, as noted in the planning study, the load in Western Australia is very temperature sensitive, and the study notes that 2003 and in particular 2004 were particularly hot years. Had the actual historic demands been temperature corrected prior to assessing the historic growth rate, then the apparent historic growth rate may have been lower and the forecast growth rate would have been lower[18]. We reiterate that this is a relatively minor concern in this instance as a different load forecast may have had a minor impact on project timing, but was unlikely to have changed the inherent justification for the project.

Overall the planning study was thorough and the conclusion that reinforcement of the 132 kV line was required by the 2007 summer seems reasonable. Western Power evaluated three different project development options and the construction of the new Pinjar-Wanneroo line was shown to be the most economic. This was primarily because the line was also needed to evacuate the power from the Neerabup terminal station, which was being constructed for other reasons. The two other options involved minor strategic upgrades to the 132 kV network. While these options would have deferred the construction of the new line, it would still have been required by 2009, when the Neerabup terminal station was expected to be commissioned.

We conclude that the project evaluation process and the decision to proceed were sound.

4.2.3 Project Implementation

The provision for line works in the business case cost estimate was $15.7 million, over 70% of the total estimated cost of $22.2 million. Three companies were invited to submit tenders for the line, but two declined to bid. Both said that the need for them to develop a tower design at a time when they had commitments in Australia and were experiencing a shortage of labour would result in them being less likely to outbid a company that held the original design of a suitable tower series.

We are a little surprised that Western Power did not hold the intellectual property rights to a suitable tower design that could have been used by all bidders. The fact that only one contractor had a suitable design available gave this bidder a degree of monopoly power, which in turn may have increased the bid price.

The price submitted by this one bidder was $19.4 million, almost 25% higher than the provision in the approved cost estimate. Western Power stated in its subsequent business case that it thoroughly evaluated the tender in respect of its technical and commercial conditions and believed it to be competitive in the current market.

Furthermore Western Power experienced significant delays in getting initial agreement to a line route and furthermore there were also internal delays completing the design due to high workloads and project prioritisation. Hence, while the business case had been approved in early 2005, tenders for line construction were not called until February 2006. All three tenderers initially declined to bid, given the required completion date of November 2006, so Western Power had little option but to extend the required completion date to November 2007. It mitigated the risk caused by this delay by ensuring that all maintenance in the area affected by the project was completed so that all lines would be in service over the peak summer season. We think this was a prudent approach.

As a result of the above issues a revised business case and tender recommendation, with the project budget increased to $27.7 million was approved by the Western Power board in June 2006.

Subsequent to the commencement of the project works following approval of the June 2006 business case, Western Power found it necessary to make significant changes to the route of the line. Specifically:

[18] The study went to some length to justify the use of the 2004 load as the starting point for the extrapolation. We think this was reasonable, given that it is necessary to design the network to cater for unusually high summer temperatures. Our concern is related to the fact that historic growth rates might not be accurate if they are based on actual demands, without temperature correction, in areas where the demand is highly temperature sensitive.

- In September 2006 Western Power was approached by a land developer requesting that the line be routed away from its property and along a proposed new road development by the City of Wanneroo. This change increased the length of the transmission line by 1.3 km and was expected to increase the overall cost of the project by $6.7 million. Legal consultants were engaged to represent Western Power in mediation proceedings in May 2007 and later arbitration in September 2007. The mediation resulted in Western Power agreeing to build the additional section of line with payment for the additional work being subject to arbitration. A negative arbitration result was announced in March 2008.

- Between September and November 2006, the City of Wanneroo approached Western Power asking that the line be realigned to suit future Neerabup semi-industrial land development and road realignment/upgrade work. These changes were forecast to increase the cost of the project by $2.6 million.

- In July 2006, a local Member of Parliament requested on behalf of property owners that a section of the line be rerouted to the other side of the road into Bush Forever land. This request was supported by Main Roads as it would provide for the development of a future second carriage way. This change was forecast to increase the cost of the project by $0.6 million.

These changes also resulted in the line being placed in closer proximity to Alinta's high pressure gas pipelines and Telstra's underground cables and a $3.6 million provision was included in the project budget to provide for the potential mitigation of transmission line induction affects. A provision of $0.4 million was also included to cover legal costs.

As a consequence of these events, an increase in the project budget to $40.9 million and a delay of the required in service date to November 2008 was approved by the Board in May 2008. This approval was made with some urgency in order to avoid possible penalty and interest charges to the line contractor.

The project was completed and placed into service in November 2008, for a total cost of $32.8 million, almost 20% below the final project budget. Western Power has stated that this was because the expected variations to the line construction contract did not materialise and most of the mitigation measures provided for were not required.

4.2.4 Conclusion

While the final cost exceeded the original budget by almost 50% and project completion was delayed by two years, this was largely due to factors outside Western Power's control. However, the delay in putting the line construction out to tender was responsible for part of the overall delay in completion. It is not clear whether this initial delay could reasonably have been avoided by Western Power.

Western Power stated in its third and final business case that:

> *In the design phase of the project in 2005 the line route selection and resultant design work were completed. These works were performed in conjunction with an extensive community consultation program with all stakeholders. At this stage of the project works there were no foreseeable problems with the project works and the selected line route.*

The delays and cost overruns that arose on this project are typical of what can occur on transmission line projects where the route is subject to community consultation and we have seen similar problems arise in other jurisdictions. One problem is that stakeholders tend to be apathetic during the initial construction phase and only raise concerns once it is clear that a project will actually proceed. It is difficult to know what Western Power can do to avoid this, other than minimise delays in order to reduce the risk of significant changes to the situation arising over the period between completion of the consultation process and the commencement of construction.

On the information available to us, the decision to take legal action against the private developer seeking the change to the line route was reasonable. It appears that a private developer has been able to force a late change in the line route for its own benefit and then avoid contributing toward the additional costs resulting from the change. On the face of it, this hardly seems fair to Western Power customers, and may have set a precedent that could make future line construction projects more costly and difficult to implement.

4.3 SHOTTS–KEMERTON LINE SECOND CIRCUIT

4.3.1 Introduction

The project was formulated to meet a requirement to increase the power transmission capacity between the Collie coal fields and the Perth metropolitan area. The increased power transfer capacity was required due to the construction of new generation in the coal-fields area and the planned retirement of generation at the Kwinana power station[19]. It involved the stringing of a second circuit on part of an existing 330 kV transmission line that ran between Muja and Kemerton and the installation of new line termination facilities at Shotts and Kemerton terminal stations. The objective was to increase the total power transmission capacity supplying Perth from the south by allowing the existing 330 kV transmission lines to share load more evenly and thus be more fully utilised. The business case cost estimate was $16.1 million including contingency and escalation and the required in service date was November 2007.

4.3.2 Project Development and Implementation

We have reviewed the system studies that identified the need for this project and are satisfied that a genuine requirement was established. Two alternative options to meet this need were evaluated. The first option involved the stringing of the second circuit to create a new Shotts-Kemerton line while the second option involved the establishment of a static variable compensator (SVC) at the Northern Terminal Station[20]. While the capital cost of the two options were similar, the line stringing project provided the best cost-benefit outcome, primarily because it had the additional benefit of materially reducing network losses[21]. The business case for the project was approved by the Western Power Board in January 2005.

The major cost component of the project was the line stringing, which was outsourced on an AS 4000 contract following a competitive tender process in which the lowest cost of three bidders was selected. Primary plant was procured using established competitively sourced draw down contracts and substation work was undertaken using Western Power's own internal resources.

During project implementation it was found that the cost of three lattice steel towers was omitted from the business case cost estimate and not included in the line contract. The

19 The retirement of generation meant that the additional power transfer capacity that would eventually be required was greater than the forecast increase in demand as the Kwinana generation is located much closer to the Perth load centre.

20 It is not good industry practice to operate high capacity transmission lines at their maximum thermal rating as capacity needs to be kept available for use following an unplanned circuit outage. The limiting factor that determines the maximum transfer capacity of the 330 kV network to the south of Perth is the availability of sufficient reactive power sources to maintain voltage at the receiving end in the event of the loss of one of the in-service circuits. This can be achieved by installing new sources of reactive power within the Perth metropolitan area. The completion of the second circuit between Shotts and Kemerton had a similar effect because it allows the load to be better balanced across the available circuits. This reduces the maximum potential load in any one circuit and thus the reactive power deficit in a worst case fault scenario.

21 SVCs are relatively new devices and Western Power was also concerned about the technology risk. However SVCs are used by other Australian transmission businesses such as Powerlink and, given that lack of reactive power sources is a major problem for the SWIS, will eventually be required by Western Power. Notwithstanding this the major reason for preferring the line option was the outcome of the economic analysis.

cost of these towers was $1.9 million including contingency. Due to timing constraints, a waiver of competition was granted using Western Power's established internal business process and the work was awarded to the line stringing contractor.

Notwithstanding this change in project scope, the final project cost was $17.3 million. As the cost overrun was less than $3 million and less than 10% of the estimated project cost, approval for the cost overrun was not required. The project was completed in December 2007, more or less to schedule.

4.3.3 Discussion

This was a low risk project for Western Power as it involved extensions that had previously been planned for, resulting in very little design uncertainty. Notwithstanding this, three towers were omitted from the business case cost estimate, and this caused a significant increase in project cost. The need for these towers should have been identified prior to completion of the business case and we think the new estimating processes when fully implemented should reduce this risk. It is not possible to quantify the impact of this oversight on the final cost of the project but we think it likely to have been material.

We also note that increases in material and equipment costs do not appear to have impacted this project. We think this may be because equipment orders could have been placed during 2005, before electrical plant costs were impacted by rising commodity prices.

4.4 WAIKIKI SUBSTATION FEEDERS

4.4.1 Introduction

This project was driven by the decision to construct a new substation at Waikiki, about 10 km south of Rockingham. The substation was required to meet growing residential load in Rockingham, which is becoming increasingly popular as a retirement area and as a dormitory suburb of Perth. This popularity was expected to increase due to the construction of the Perth-Mandurah rail line and the extension of the Kwinana freeway.

The project was approved in April 2005 as part of a combined business case with the new substation. The total estimated cost of both projects at the time of approval was $8.86 million, of which the distribution component was $1.35 million. In November 2007 an increase in the project budget of $2.65 million was approved, bringing the total budgeted cost of the project to $4.00 million. The project is now substantially complete with an expected actual project cost of $3.67 million.

The project was included in this review because of the substantial difference between the budgeted and actual costs. The review will therefore focus on this aspect of project management and will not consider in detail the initial development of the project as this was driven primarily by transmission planning requirements. We do note however that, while the project was managed separately from the Waikiki substation project because transmission and distribution augmentations are separately budgeted by Western Power, the transmission and distribution projects were combined for options analysis and business case approval. This was appropriate since for practical purposes the two projects were interdependent.

As originally scoped for determining the business case cost estimate the project included:

- installation of nine sections of 22 kV underground cable totalling approximately 1.5 km;

- upgrading eleven sections of 11 kV overhead conductor totalling approximately 7.6 km;
- relocation of seven reclosers; and
- installation of one new relcoser.

4.4.2 Implementation

The escalated business case estimate for this project was $1.35 million. This appears to have been based on a current cost estimate of $1.25 million (including a 10% contingency), prepared in March 2004. This equates to an escalation factor of 8%, which was not unreasonable given that the substation required in service date was November 2007.

The business case was not forwarded to the Managing Director for approval until February 2005. Notwithstanding the delay of almost a year, the project cost was not updated to reflect the current cost at the time the business case was submitted for approval. While we believe the budgets for all business cases should be refreshed before the business case is finalised for approval, this was not a major factor in the cost escalation of this project as commodity prices did not start to increase exponentially until mid-to-late 2005.

Western Power has given the following reasons as factors in the substantial increase in the actual project cost compared with the initial budget.

- Materials cost increases between the approval of the business case and project implementation. Materials prices in the distribution industry are largely driven by the cost of copper and aluminium. The copper commodity price rose from $4,000 per metric tonne in late 2004 to $10,000 per metric tonne in late 2006, while the corresponding aluminium price rose from $2,500 to $3,500 over the same period. During the presentation Western Power noted that the cost of copper cable rose from about 69 cents to 143 cents per metre from early 2004 to early 2007. We think the project cost would have been lower if aluminium cable had been used instead of copper. As indicated above, not only is aluminium significantly cheaper than copper but the proportionate rise in price over the recent boom in commodity prices has been lower. Western Power has now started using aluminium rather than copper distribution cable but this change only came into effect after this project had been completed.
- Increases in labour cost. The project budget was likely based on the cost of Western Power's own internal resources. This project was implemented at the peak of the economic boom in Western Australia when both Western Power and its contractors faced shortages in skilled labour, which inevitably increased labour costs. Arguably, this project was impacted twice, firstly by an unanticipated rise in general labour costs and also by the need to use external contractors, with labour costs higher than Western Power's internal resources.
- Changes in the project scope. The change control request dated 28 June 2007 stated that:

  > *The Rockingham distribution network has been subjected to significant change in recent years and this has affected the requirements of the scope of work. Inadequate and inaccurate network information has also masked the full extent of the required network upgrades.*

  Western Power has not quantified the impact of changes to the scope of works on the project cost. However, given the magnitude of the cost overrun, we expect it was significant. We note the indication in the change control request that the project was under-scoped because of inadequate information being available at the time the project cost estimate was prepared. This seems to have been a recurring problem for Western Power, which we think will be addressed through the changes in the cost estimation process discussed in Section 3.1.

The change control request indicates scope changes were also necessary as a result of changes to the distribution network between the time the project was initially scoped in 2004 and project implementation in 2007. It appears that the load on the network increased significantly over the period – Western Power noted in its presentation an unanticipated increase in demand at Rockingham Hospital, and installation of a second transformer at Waikiki substation is now in the design phase.

The business plan cost estimate allowed an initial three feeders, with provision for a fourth feeder to be added at a later date. It is possible that Western Power found it necessary to accelerate the connection of the fourth feeder, but there is no indication of this. It is also possible that there was a need to strengthen the distribution network in the vicinity of the substation and Western Power included this work in the project, even where it was not directly related to reconfiguring the network to connect in the new substation.

- Delays in completing the new Waikiki zone substation. The substation was originally scheduled for completion in November 2007 and the work was substantially complete by early March 2008. We think the impact of this delay on the budget overrun would have been relatively minor.

4.4.3 Discussion

Projects involving a reconfiguration of the distribution network can be difficult to scope and forecast accurately, particularly when there is a significant delay between planning and implementation. Such projects are particularly susceptible to “scope creep” through the inclusion of work only indirectly linked to the project objective. We suspect this may have occurred on this project.

We also note that the project scope change request dated June 2007 was for \$4.00 million. The date of approval is not known. At the time of the request all contracts would have been ready for award and the project cost at completion should have been known with a high level of certainly. The rounded nature of the final budget estimate, and the fact that the project came in over 8% below the updated budget indicates that a generous contingency may have been included in the change request estimate, either to avoid the potential embarrassment of a further cost overrun, or so that “scope creep” could be accommodated. The fact that change included an extension of the project to June 2008, when it should have known at the time that the Waikiki substation would likely be commissioned in February 2008, supports this.

We note that the expected cost of projects exceeded the initial budget by 172%, and consider this level of budget overrun unacceptable. While such increases may be absorbed for small projects by reallocating funds from other areas this is not possible for larger projects.

The extent to which this project cost overrun should have been better controlled by Western Power is not clear. The time lag between preparing the initial project budget and project implementation was driven by the lead time required for the new zone substation and was thus outside the control of Western Power’s distribution sections. The materials cost increases over this period were outside Western Power’s control and the information we have seen indicates that Western Power acted appropriately to minimise installation costs.

We also cannot assess whether the changes to the project scope could have been better managed. As noted in Section 4.4.1 the project scope used for the business case estimate was very specific, but this was later found to be flawed due to *inadequate and inaccurate network information*. There were also changes to the project scope arising from changes to project requirements between the time of initial project scoping and the time the final design was completed. We do not have sufficient information to assess the proportion of the project cost overrun was due to inaccurate scoping of the original business case and the proportion due to the evolution of the distribution network over the period between project approval and project implementation. We also cannot assess whether work not directly related to the project objective was included in the project for convenience.

4.5 MID-WEST TRANSMISSION AUGMENTATION

4.5.1 Introduction

In October 2007, Western Power submitted to the Authority a proposed major augmentation of the transmission network involving the construction of a double circuit 330 kV line in the mid-west region and associated works including a new 330 kV terminal station at Moonyoonooka, east of Geraldton, for assessment against the regulatory test. The application indicated that construction would commence in mid 2008 and the project would be completed in November 2010. The estimated construction cost was approximately $300 million. The Authority issued a regulatory test determination in December 2007, which allowed the augmentation to proceed in accordance with the design proposed by Western Power.

At the time of completing this review the estimated cost had escalated to $595 million excluding contingencies for foreign exchange and commodity price variations. This review considers the project only in the context of the impact of Western Power's works program delivery procedures on the changes in the project cost and schedule. It does not revisit the need for the project nor the validity of the proposed option, as these have already been assessed by the Authority in making its regulatory test determination.

4.5.2 Discussion

Following the approval of the regulatory test, in May 2008 Western Power applied to the Authority for preapproval of the NFIT in accordance with clause 6.71(b) of the Code. The Authority gave a final decision on this application in September 2008.

In late 2008 Western Power allocated the project to one of its two alliance partnerships for construction, thereby avoiding the need for competitive tenders to be called as envisaged in the regulatory test application, but ensuring that all construction costs were visible to Western Power through the open book arrangement in the alliance agreement. Using these costs, the construction cost was re-estimated to be approximately $595 million (excluding a contingency for foreign exchange and commodity price variations), almost twice the amount of the NFIT approval granted in 2008. Under the Code, Western Power can proceed to construct the line but would have to apply for retrospective NFIT approval for any expenditure over the $300 million approval it already has. Alternatively it could make a further application for new NFIT approval before it allows construction to commence. Western Power has indicated that it will not commence construction until it has NFIT approval for the full estimated cost of the project.

The current status of the project is:

- network planning for the project has been completed;
- the project delivery strategy has been determined and evaluated;
- risk strategies especially for foreign exchange and commodity price risks have been determined;

- most aspects of the line and terminal design are well progressed; and
- designs for towers and foundations are in progress.

The required in service date for the project is the requirement to supply a new iron ore mine at Karara, north-east of Enaebba, which is scheduled to begin production in late 2010. Given the delays in obtaining the required approvals for the reinforcement, the construction schedule has been revised and it is now proposed that the southern section of the project between Pinjar and Enaebba will be constructed first for completion by November 2010[22]. The northern section, including the line between Enaebba and Moonyoonooka and the new Moonyoonooka terminal station is now scheduled for completion by November 2011. It is not known whether commencement of production at the new Karara mine will be delayed on account of the current world economic slump and whether this will allow the first stage of the project to be further delayed.

The major problem that the project has encountered has been the significant underestimation of the project cost that was used for the approval process. The reason for this is not clear but we suspect it is largely due to the weaknesses in the estimating process described in Section 3.1. The estimate used for the regulatory and NFIT test applications was prepared in November 2005 and escalated to November 2006. We consider that the substantial increase in commodity prices since the initial price estimated was prepared and the decision to allocate the project to an alliance partnership could also have been contributing factors.

The current cost estimate of $595 million includes alliance partnership costs of $454 million and other costs of $138 million. Other costs include direct costs by Western Power of $59 million for the component of the project such as SCADA that it will complete using internal resources, a Western Power risk provision of $40 million and an overhead cost recovery by Western Power of $42 million. Western Power has benchmarked the alliance partnership's estimated line costs against similar external projects with input from three external consultants as well as a similar project that it recently delivered using a competitive tender process and this shows that the line cost estimate was reasonable. It did indicate however that competitive tendering was likely to lead to lower cost outcomes than alliance partnering. Western Power also contracted an independent estimator to review the cost estimate, which concluded that the estimate reached was comparable to market rates. We have not reviewed the revised estimate, but conclude that Western Power is now going to some lengths to ensure that it is defensible. We did note however that the risk provision in the alliance partnership's estimate for its component of the work was only about 4% of its estimated direct costs, whereas the risk provision in the Western Power component of the estimate was 68% of Western Power's direct costs. Western Power considers that it faces a greater level of uncertainty than the alliance partnership, but the reason for this is unclear. We think it should be able to reduce this risk component of the estimate.

Western Power has also revisited the regulatory test analysis and found that the increased costs do not change the ranking of the different options evaluated. We are not surprised at this since we understand the major cost in all options was the cost of overhead lines. We would therefore expect the cost increases for all options to have been similar when normalised against the base costs used for the original regulatory test analysis.

Western Power's experience with this project reinforces the importance of using accurate estimates for project development and the need to regularly update these estimates where the development process covers an extended time period. We believe that the use of generalised escalators for this updating process is insufficient and that major cost components of the estimate should each be revised using the most recent and accurate costs available. We also believe that the NFIT pre-approval process needs to be left as late as possible in the project development process and should use a cost estimate

[22] In the original construction schedule the northern section of the line was going to be constructed by November 2009 and the southern line section and Moonyoonooka Terminal Station completed by November 2010.

specifically updated for the purpose. This is because the Code requires the Authority to approve a new facilities investment of a specific amount and the Authority cannot pre-approve new facilities expenditure unless it is satisfied that it is efficient. This efficiency test requires Western Power to demonstrate that its estimated cost is commensurate with that which would be *invested by a service provider efficiently minimising costs*[23]. We cannot see how the Authority can meaningfully make this assessment if the estimated cost provided with the NFIT application does not meet Western Power's own criteria for a business case estimate.

Finally the date of the current cost estimate and the extent to which it reflects the reduction in commodity prices resulting from the recent global economic recession is not known. It may be that the current cost estimate is at the high end of the likely range of cost outcomes if recent commodity price movements have not been factored in.

4.6 VEGETATION MANAGEMENT

Western Power's strategy for the control of vegetation around its network assets has evolved incrementally over the last six years. As a result of this evolutionary process, vegetation management within Western Power is now significantly different from the start of the period.

A submission to the Board of the then aggregated Western Power dated March 2005 notes that prior to 2003 the networks business unit managed some 40 vegetation control contractors across its transmission and distribution system with contracts of varying nature and scope and with a range of contractor performances. Early in 2003 the then aggregated Western Power implemented a two-stage project to improve the management of vegetation control across the SWIS.

Stage 1 was an interim arrangement introduced in 2003 that reduced the number of contractors to 10. The network was divided into 10 vegetation management zones and each zone was allocated to a single contractor who was responsible for all vegetation services within that zone. Under this arrangement it appears that the planning and management of the vegetation work undertaken by the 10 contractors was done by Western Power staff.

In 2005 a three-year vegetation management contract for the whole of the SWIS network area was awarded after a competitive tender process. Financial modelling undertaken as part of the tender evaluation process forecast savings over the three year contract period compared with a continuation of the existing vegetation control strategy. The contractor was responsible for both managing and implementing the vegetation control effort including customer contact and data control and the involvement of Western Power staff was to be reduced to a compliance auditing role.

In early 2007, following a bushfire caused by vegetation contacting a line, it was apparent that the volume of vegetation control work required to meet operational and safety requirements was significantly higher than provided for in the contract. In addition, following a safety incident it became clear that more stringent work procedures than the contractor was currently using were required. As a result contact variations were required.

The bushfire and safety incident highlighted risks with a single contractor arrangement and also indicated a need for Western Power to more closely control the work. Western Power therefore decided to review its approach and prepared a new vegetation management strategic plan. As an interim measure, in order to maintain the momentum of the vegetation management program and in particular to ensure that the "bushfire cut" for the 2009 summer was completed on schedule, the existing contract was extended for a further year in two phases. The first phase extended the contract for six months until 31 December 2008 with substantially the same terms and conditions, while strengthening

23 See clause 6.52(a) of the Code.

Western Power's rights through sterner key performance indicators, step-in, cure and termination provisions. The second extension, approved in October 2008 and lasting to 30 June 2009, had substantially modified terms and conditions including provision for flexible resourcing options and provision for the use of internal and new contractor resources as appropriate. Western Power is now internally undertaking key management functions such as data and program management.

Western Power is not planning for the implementation of its new vegetation management strategy after the current contract expires in June 2009. The new strategy was developed after considering the vegetation management models in place in various utilities in the eastern states of Australia. In some respects the new arrangement will revert to the model in place between 2003 and 2005 in that there will be a limited number of different contractors, each allocated to specific area zones. The objective will be to reduce the risk inherent in using a single contractor and introduce a degree of competitive tension. The contracts will be performance based and there will be a rigorous internal audit regime verified by third party independent audits. Over time it is planned to move from a reactive cutting mode to a sustainable maintenance mode through the introduction of proactive strategies such as the replacement of existing vegetation in the vicinity of lines with alternative slower growth species. Data management will be undertaken internally. Tender documents for the new contracting arrangements have been prepared and sent to prospective contractors.

It appears to us unlikely that the new arrangements will be in place before the beginning of the 2010 financial year and there is likely to be a hiatus before new contractors are appointed and have time to mobilise and get up to speed. Western Power will need to ensure that the delay does not put the "bushfire cut" for the 2010 summer at risk. We understand that Western Power's vegetation steering committee is putting interim strategies in place to mitigate this risk.

4.7 ROUTINE DISTRIBUTION NETWORK ASSET INSPECTIONS

Following the approval of the OSA business case for rationalising asset inspections Western Power went out to competitive tender for external contractors to undertake the routine inspection of distribution line assets. For the management of this inspection program the Western Power distribution network is segregated into 1,850 maintenance zones, with the program planning based on the inspection of a quarter of all assets in each maintenance zone in any financial year. All assets are thus inspected on a four year cycle.

Tenders were called Australia wide in February 2007 and 14 responses were received. Two contractors were appointed one for the northern region and one for the southern region and the outsourcing commenced at beginning of the 2007/08 financial year. The program targeted the inspection of 180,000 poles per year, at a cost of $9.7 million in the first year. Each contract is for two years with a right of renewal for up to a further two years.

The scope of work includes:

- routine inspection of all power poles and stay poles and the testing and treatment of wooden poles;
- a visual inspection of all pole top hardware and line conductors, including sectionalisers, reactors and switches, from the ground using high-power binoculars;
- the correction of minor maintenance defects at ground level; and

- provision of data on equipment condition in a format that is suitable for direct entry into Western Power's distribution facility management system (DFMS), which is used to manage the defects rectification process.

A significant shortcoming in the scope of work is that excavation and inspection of wooden poles below ground level is required at one location only rather than around the full pole circumference. Hence the inspections as currently undertaken are not fully consistent with industry best practice with the result that wood rot below ground level may not be detected. This would seem to be a significant deficiency with the existing program and Western Power has included a provision in its AA2 expenditure forecast for additional funding to allow the inspections to be brought up to standard.

Western Power undertakes a quality audit of the work done by the two contractors, which involves a follow-up inspection by its own staff of 10% of the inspected poles.

Only 150,000 pole inspections were completed in the 2007/08 financial year at a cost of $8.42 million. One reason for the shortfall in number of poles inspected was a delay in mobilisation by one of the contractors, which was sufficiently serious to require a reallocation of some of the planned work to the second contractor. The shortfall of inspected poles has been carried over to the second year of the contract. To date 160,000 poles have been inspected in the current financial year and Western Power estimates that the backlog of inspections will be cleared by about September 2009.

The unit cost of inspecting each pole in the first year of the program was $56, compared to a budget of $54. The cost increase was due to additional costs of quality assurance and project management as well as additional costs incurred in accessing poles in difficult areas.

4.7.1 Discussion

While the unit costs incurred though outsourcing this work may be more expensive than through internally resourcing the program we see a number of advantages in the current approach. Outsourcing this work means that it is ring-fenced from other maintenance activities; that since the budget is required to pay the contractor it is not available for reallocation to other works; and that the contractor has a strong incentive to properly complete the works.

The need to manage a dedicated external contractor means that Western Power itself must adequately plan and monitor the inspection activities, and it is clear that it is now doing this. However we are surprised that Western Power finds it necessary to audit 10% of the poles inspected since statistical theory would suggest that a much smaller sample should be adequate to monitor the performance of a good contractor with a high level of confidence. If these audits are showing that significant numbers of serious defects are being missed by a contractor, then Western Power needs to take action to improve the situation; otherwise we think the level of audit could be reduced significantly without compromising the integrity of the process.

Western Power indicated during its presentations that it is trialling a number of sophisticated non-invasive and less labour intensive wood pole inspection techniques, but to date has not found one that was as satisfactory as the sound dig and drill methodology that its contractors were currently using. However as noted above, Western Power is not currently requiring full implementation of the sound dig and drill technique and that as a result serious pole defects below ground may be missed both during the inspection and also in Western Power's own follow-up audits. Given the safety implications, this would seem a serious limitation in the existing process and we support the inclusion of funds in the AA2 operations expenditure forecast to allow this to be addressed.

4.8 REPLACEMENT OF DISTRIBUTION POLES

4.8.1 Introduction

The replacement of distribution poles was included in this review because Western Power's unassisted pole failure rates are ten times greater than experienced by comparable utilities on the east coast of Australia. Furthermore, the Office of Energy Safety's 2008 draft pole management audit findings were critical of the rate at which poles were being replaced and considered higher rates of replacement were necessary if safety issues are to be satisfactorily addressed.

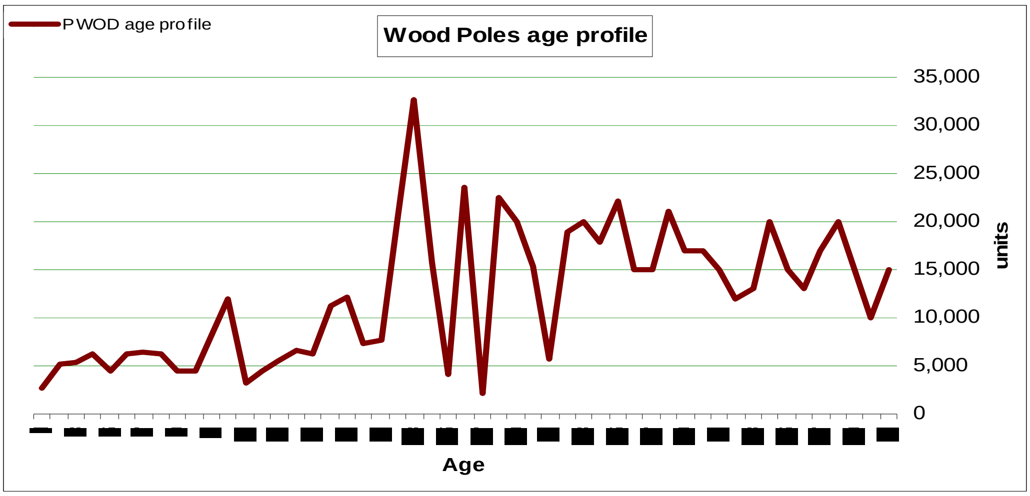
4.8.2 Pole Replacement Requirements

The AA1 capital expenditure forecast provided for the replacement of 12,700 poles over the three year regulatory period, with the replacement of 2,700 poles in 2006/07 and 5,000 poles in each of the following two years. However in July 2008 the Board approved the replacement of an additional 2,000 poles in 2008/09, bringing the total to 7,000 poles. To date a total of just over 6,000 poles have been replaced this financial year.

Western Power also has a life extension policy in place whereby poles showing some deterioration are reinforced by supporting the pole at ground level with galvanised steel support columns. At the time the AA1 capital expenditure forecast was prepared a backlog of almost 12,000 poles had been identified as requiring reinforcement. The AA1 forecast provided for the reinforcement of 32,000 poles over the AA1 regulatory period notwithstanding the fact that only around 2,500 poles had been reinforced in 2005/06. The number of poles actually reinforced over this period is not known.

There are approximately 630,000 wooden poles on Western Power's distribution network. In its presentation Western Power provided the age profile of this wood pole population shown in Figure 2. Broadly the age profile shows that there are a total of around 50,000 poles aged between 1 and 10 years, 75,000 poles between 11 and 20 years and 450,000 poles aged between 21 and 50 years. The profile does not show poles greater than 50 years old, but based on a total of 630,000 poles, we can assume that 55,000 poles fall into this category.

Figure 2: Age Profile of Wooden Poles



In order to estimate the required rate of replacement, assumptions must be made as to when reinforcement and replacement are required on average[24]. The Office of Energy

[24] This does not imply that replacement should be based on asset age. Individual poles deteriorate at different rates and we agree with the industry standard practice of reinforcement or replacement based on the assessed asset condition

Safety assumes that reinforcement is required after 25 years and replacement after 40 years. Western Power has historically assumed an average pole total life of 60 years but stated during the presentation that this was probably high. For the purposes of this analysis we are assuming reinforcement after 25 years and replacement after 50.

In its AA2 capital expenditure forecast Western Power has assumed reinforcement of 30,000 poles and replacement of 22,500 poles over the three year regulatory period. However based on the above age profile it appears reinforcement and replacement rates should be 15,000 poles a year each if current backlogs, which are already relatively high are to be maintained. Since the "smoothed" age profile of poles currently aged between 20 and 50 years is relatively flat, this rate would not change significantly if different lives were assumed[25]. Thus it appears that Western Power may have underestimated the required rate of pole reinforcement and replacement over the AA2 regulatory period.

Western Power stated that it used recent pole condemnation rates to determine the number of poles that it assumes will require replacement during the AA2 period. It therefore appears that current pole condemnation rates are lower than they should be, given that they are lower than our analysis of the age profile and the assumed asset life. Either the pole population is in better condition than indicated by our analysis (indicating an incorrect age profile or a pessimistic assumption of average life), or the inspections are flawed and poles that should be identified for replacement are being assessed as being in satisfactory condition.

In Section 4.7 we note that the inspections as currently undertaken do not involve digging to inspect the condition of the pole below ground level, and that as a result pole deterioration below ground level may not be detected. This is one possible reason why current condemnation rates are lower than expected.

More information is required before firm conclusions can be reached. However, it is reasonable to conclude that the failure of wooden poles remains a serious safety and reliability issue and that improvement is unlikely unless the rate of wood pole replacement is increased.

4.8.3 Management of Pole Replacements

The OSA program identified the fragmented manner in which maintenance of the overhead distribution network was managed as an area where efficiency gains were possible. At disaggregation, the inspection and subsequent replacement of condemned poles, where required, was managed separately from the maintenance of other parts of the distribution network. These works have now been integrated.

As noted in Section 4.7 the Western Power network is segregated into 1,850 maintenance zones. Each maintenance zone is assigned a bush fire rating so that those zones in areas of high fire risk can be subjected to a more intensive maintenance regime. A quarter of the network in each maintenance zone is inspected each year through the four-yearly asset inspection program described in Section 4.7.

Western Power is currently implementing a new process whereby the work indentified by these inspections in each maintenance zone is consolidated into a single maintenance work package which is then assigned either to Western Power's internal field staff or to an external maintenance contractor for execution. Hence pole replacement is integrated with other maintenance work on the distribution network in a way that permits either internal field staff or external contractors to plan the implementation of the maintenance work required in each zone so that it is implemented as efficiently as possible.

following inspection. However, it is useful for planning and budgeting purposes to determine the average age at which reinforcement is required and the average total life of a pole following a mid-life reinforcement.

25 If a life of 60 years was assumed and the age profile was assumed to fall after 50 years, a lower replacement rate would be indicated. However, given our estimate of 55,000 poles aged greater than 50 years and Western Power's acknowledgement that the 60 year life assumption is optimistic, this scenario would seem unlikely.

We have reviewed the business case describing the implementation of the process in the North Country area. While not entirely clear, it appears that each work package will be assigned directly either to a Western Power depot for implementation by internal resources based at the depot or to a preferred external contractor. When assigned to an external contractor, the contractor will be asked to provide a quotation, which will then be assessed for reasonableness by Western Power against a range of criteria. While this approach would not involve competitive bidding, we consider it acceptable provided Western Power benchmarks contractors' unit rates against the cost of its own resources and monitors the comparative efficiency of contractor performance on an ongoing basis.

This more integrated approach appears to be an initiative by Western Power to increase the efficiency with which distribution maintenance works are delivered, in an environment characterised by increasing work volumes, constraints on resource availability and a consequent increase in resource cost. It is likely that the current economic recession will relieve some of the pressure on resource availability and cost and therefore allow Western Power to increase the rate at which it is able to reduce the maintenance backlog on the distribution network. The Authority will need to be assured that the efficiency gains that have been obtained during a period of constrained resource availability are not eroded in a more relaxed operating environment.

4.9 DISTRIBUTION TRANSFORMER REPLACEMENT

This section describes a program to proactively manage the loading on larger distribution transformers and on the low voltage network. The program was initiated in response to the high loads experienced during the 2004 summer when more than 50 transformers failed.

The program is initiated in April of each year following the summer period when network loads are highest. The process used to scope out the work required for the following financial year is described below.

- Using software developed in-house, Western Power forecasts the following summer peak load on all transformers rated at 300 kVA and above. These analytical forecasts are supported by data from the peak demand meters now included in these larger transformers. The forecast loads are compared with the transformer capacities to identify transformers that will potentially be overloaded. This predictive load forecasting is only applied to the larger transformers on the basis that it would be both impractical and uneconomic to proactively forecast and manage the loads on smaller transformers, which should therefore be allowed to run to failure. We agree with this.

- Records of low voltage fuse failures are scrutinised and transformer sites where a large number of fuse failures are reported are targeted for further investigation.

- The sites that are identified as potentially requiring an upgrade are visited to verify the data used for the load forecast and to confirm that asset records of the site are accurate. Following these visits a list of sites to be included in the following year's program and the required mitigation at each site is developed.

- This information is used to prepare an annual business case for the program. The business case costs are based on the average costs per job undertaken under the program during the previous year.

- The detailed design for each site is outsourced by placing orders on preferred vendors. Western Power has standing contracts with consultants that are capable of providing the necessary design services, and individual jobs are procured by way of purchase orders placed against the standing contracts. The standing contracts were established through a competitive tender process and allow individual jobs to be priced using a schedule of rates. Alternatively, for larger jobs, a competitive fixed price may be required.

- Construction work is outsourced in a similar manner by placing orders against standing contracts in place with preferred contractors. Western Power generally supplies the equipment and material required from its own inventory.

For the 2007/08 financial year the approved budget for the program was $7.8 million. A further $1.8 million was subsequently allocated using the change control process. Work completed under the program included the replacement of 166 pole top transformers, 67 pad mount transformers and 40 low voltage network reinforcements. The actual cost was $8.4 million, with a further $0.5 million outstanding due to land acquisition issues.

The program appears very successful in that there were only two transformer overload failures recorded during the 2008 summer. The processes used by Western Power to plan the work and minimise costs seem appropriate. We believe this program is worthwhile and note that the low voltage network is a part of the asset base that is neglected by many utilities. We note also that the cost of the program will be partly offset by savings through avoidance of premature distribution transformer failures.

4.10 TRANSMISSION LINE INSPECTION

Inspection and maintenance of the transmission system is managed separately from the distribution system. The objective of the transmission line inspection and maintenance program is to limit pole failure to one in 10,000 poles per year and all faults to 0.5 faults per 100 km of line per year, marginally lower than the level currently being achieved.

Transmission system line assets are much smaller in number than distribution system line assets. Hence a more individualised approach to asset management is possible and the transmission line inspection program consequently goes beyond ground based inspections to include helicopter surveys and a range of non-destructive condition assessment tests. Strategies used are summarised in Table 1 below. The more intensive inspection regime also reflects the fact that transmission lines are more critical to the overall operation of the power system.

Table 1: Transmission Line Inspection Strategies

Strategy	Frequency	Comment
Routine helicopter inspections	6-monthly	Fly-by to identify severe and obvious asset faults. Used in country areas.
Methodical helicopter inspections	3-yearly	This involves a detailed inspection of each structure. Photographs are taken. Helicopter inspections have developed to the stage where relatively minor defects can now be identified and recorded.
Pole ground inspection	Yearly	Generally a drive-by to identify obvious asset faults. Used in metropolitan areas, and where lines can be observed from the road.
Base inspection	4-yearly	This is similar to the 4-yearly inspection of distribution poles and involves drilling to test for the amount of good wood.
Structural Inspection	4-yearly	This is a detailed inspection of steel towers and poles, primarily for corrosion.
Electromagnetic conductor corrosion detection	5-yearly	This inspection detects corrosion of the internal steel core of steel reinforced aluminium line conductor. It requires a remote controlled trolley containing the electromagnetic test equipment to be attached to, and travel the length, of each conductor. The inspection is normally done with the line energised.
Infrared hot spot detection	4-yearly	An infrared camera is used to identify hot spots caused by loose or corroded connections and joints.
Vegetation inspections	Yearly	Visual inspection.
Insulator siliconing	10-yearly	A silicon based compound is applied to insulators on lines located in coastal or polluted areas to prevent arcing caused by pollutants deposited on the surface of the insulator.
Insulator washing	Yearly	Insulators in polluted areas are washed to prevent the deposit of pollutants. This is much less costly than siliconing, but it is not as effective over time.

Western Power currently has 273 transmission lines in service. An individual inspection and maintenance program is developed for each line having regard to the type of line and its age, condition and location. Most work is outsourced using period contracts of a nature similar to those described for distribution line maintenance in Section 4.7. Western Power's transmission maintenance program management team is responsible for programming the inspection and routine maintenance work to be undertaken by contractors and monitoring the cost of the work. This review has seen spreadsheets that indicate that this is actively being done. There is a high level of auditing of the work undertaken by outsourced contractors.

We understand that transmission line inspections and routine maintenance have historically been relatively better resourced and undertaken to a higher quality than corresponding work on the distribution system. We consider the processes currently in place to be effective and consistent with good industry practice.

4.11 STRATEGIC PROGRAM OF WORKS

The disaggregation of Western Power and the introduction of an electricity market resulted in three challenges related to the development of Western Power's information technology (IT) and management information systems.

- Systems previously shared by the now disaggregated companies needed to be split or replaced;
- New systems needed to be implemented to manage new functions arising from the wholesale electricity market rules; and

- Projects put on hold during the period leading up to disaggregation needed to be progressed insofar as they were relevant to the networks business.

In response to these challenges Western Power established a governance body, the IT Council, to oversee this systems development work. The IT Council integrated the major projects into a single program, which it called the Strategic Program of Works (SPOW).

For management and control purposes SPOW was divided into three subprograms, the customer subprogram, the enterprise subprogram and the asset and works subprogram. In September 2008, the SPOW program manager wrote a paper for the IT Council, which concluded that the asset and works subprogram would not achieve its objectives for the AA1 regulatory period and recommended a change in the strategic direction of the program. While many of the problems encountered were of a technical nature, there were also higher level strategic issues to be addressed if successful outcomes were to be achieved.

- There were two work streams trying to redesign and develop business processes; Operational Excellence, which was implementing the Lean Six Sigma initiative, and SPOW. These two work steams reported to the executive through different channels and appeared to be leading the business in different directions.

- Systems development was being driven by the needs of the IT consultant that was writing the software rather than the needs of the business. Software development was proceeding without agreement within the business on new process design, and the SPOW implementation team was focused on ensuring that the consultant delivered to its statement of work rather than on meeting the requirements of the business.

- There was no decision making forum for enterprise wide system components. There were data structures, processes and system configurations that had ramifications across the business, but there was no forum within Western Power to make these decisions. As a result the projects within the subprogram were unilaterally taking on this role.

- Insufficient resources from within the business were made available to work on the project. Often the business resources promised by branch managers failed to materialise. As a result not only was the program under-resourced but the resources that were available did not have an adequate understanding of business needs.

- The original program logic was flawed because the designers did not fully understand the constraints imposed by existing IT systems.

- The data quality in some areas was poor, in some cases so poor that it would render the system being designed ineffective.

It seems that the SPOW problems related primarily to the asset and works management subprogram, and implementation of the other two subprograms is largely complete. This appears to be because the needs of the other two subprograms were able to be more precisely specified and were not dependent on the definition of business processes that impacted all parts of the business.

The concerns expressed in the September 2008 paper have been accepted by Western Power management and key changes have been put in place. In particular SPOW has been moved out of IT and into the Enterprise Solutions Partner, which is responsible for delivering the major business improvement programs within Western Power. This has enabled it to work closely with Operational Excellence and the two work streams are currently working closely together on developing an “operational value chain”, which will define and specify the processes (based on the Lean Six Sigma business process improvement philosophy) through which Western Power delivers its required business outcomes to stakeholders. Resources have been secured and assigned full time to the program. Many of these resources are currently seconded to the operational value chain development with the intention that they will return to SPOW with an in depth knowledge of the business process that the asset and works management subprogram will need to support. Furthermore the ongoing implementation of much of the SPOW program has been deferred until outputs from the operational value chain initiative are available. In addition a business reference group made up of branch managers has been established to maintain alignment with an overall business vision and strategy.

The total expenditure on the asset and works management subprogram to 28 February 2009 was $25.3 million. Of this approximately $13.1 million has been spent upgrading Western Power's Ellipse asset management tool, which we understand will be the key data repository for the new process software to be developed through the subprogram. In October 2008 the Board approved a business case that recommended that work on the asset systems strategy and design project within the asset management subprogram be stopped and the $5.1 million unspent funds be reallocated to fund the first tranche of the redesigned program. Funding for further tranches of the program will be dependent on the Authority approving Western Power's AA2 expenditure forecast.

It is probably fair to conclude that much of $25.3 million spend to date on the asset management subprogram has been ineffective. However, the presentation for this review demonstrated a good understanding of the reasons for the deficiencies in the subprogram as implemented to date and Western Power appears to have made appropriate changes to address the shortcomings. The availability of comprehensive asset data in electronic information systems and the development of standard business processes based on the use of computerised management information is now standard practice in the industry. We believe that the asset management subprogram of SPOW is important to the development of effective governance processes and also that funding allocated to this subprogram during the AA2 regulatory period will be more effectively utilised.

5. SUMMARY

5.1 INTRODUCTION

This section summarises our general findings in respect of Western Power's governance processes and its management of capital and operational expenditures. These findings are based both on our review of relevant documents provided by Western Power and on our discussions with Western Power staff on 15-17 April 2009.

The AA1 regulatory period (2006/07 to 2008/09), which has been the focus of this review was characterised by significant changes within Western Power. These changes have been driven both by disaggregation and also by the need to respond to a booming Western Australian economy, which resulted in high load growth and more particularly, an unprecedented customer driven demand for network connections. As a result of these changes, the governance and business management systems now in place are very different from the systems at the beginning of the regulatory period. The changes are ongoing, notwithstanding the recent slowdown triggered by the current global recession.

We found the pace of change over the past three years a problem for this review. The documents provided, and the presentations given to us, tended to focus on what is currently happening and what is planned for the future, rather than what went on in the past. While we tried to find information on past activities, and questioned many of the presenters in some detail, it was often difficult to get a complete picture, not least because many of the people we talked to were relatively new employees. Hence, while we believe our descriptions of current and planned systems and processes to be reasonably accurate, there is a degree of speculation in our description of Western Power as it used to be and of the changes that have occurred over the AA1 period. We therefore note there may be minor inaccuracies.

5.2 WESTERN POWER AT DISAGGREGATION

Western Power was originally a vertically integrated government corporation responsible for electricity generation, transmission, distribution and retail operations throughout the state of Western Australia. In April 2006, Western Power was disaggregated into four separate business units. The trading name "Western Power" was assigned to the Electricity Networks Corporation, which became the new owner and operator of the transmission and distribution network that formed part of the South West Interconnected System, the interconnected power system supplying the south west corner of the state.

At the time of disaggregation it seems that Western Power was split into five relatively self-managing cost centres. The transmission network was centrally controlled from the Perth head office while the distribution network was divided into four separate area operations; Metropolitan, North Country, South Country and the Goldfields.

Western Power was (and still is) allocated an operating budget by the State Treasury. At the time of disaggregation there appears to have been an ongoing legacy of under-expenditure on the network (and particularly the distribution network) due both to government budget cuts that appear to have continued over at least the previous ten years and to an internal priority for the allocation of resources to generation at the expense of transmission and distribution.

It would seem that the available budget was internally allocated across the five cost centres and each was left to manage its own affairs as it saw fit, provided it operated within the allocated budget. Field work, including minor capital works, was generally undertaken using internal resources, supplemented by small local contractors, often owned or staffed by former Western Power employees. Since there was little central control of how or when these contractors were used, it is likely that they became an almost seamless extension of Western Power's own internal work force. As the primary means of centralised control was budgetary, cost centres were left to do the best they could with the resources they had. It is probable that the focus was on managing inputs rather than delivering outputs and that, as resources were prioritised into meeting customer driven demands and "fighting fires", preventive asset inspection and maintenance activities were sometimes left to languish.

It is also worth noting that Western Power's internal operating and capital expenditure budgets for the three year AA1 regulatory period were based on the expenditure forecast that it provided to the ERA in support of its AA1 access arrangement.

5.3 DRIVERS FOR CHANGE

Our document review and the comments made by Western Power staff indicate that the primary driver for change was the unprecedented demand for new customer connections as a consequence of the booming Western Australian economy. This resulted in an unexpected increase in customer driven work, which could not be deferred and which required resources to be diverted from preventive maintenance activities.

This diversion of resources from preventive maintenance, combined with the historic expenditure restraints, has caused a deterioration in network condition to the extent that the Office of Energy Safety now considers it a significant safety hazard. Identified safety issues include failure of wood poles, pole top fires, broken and falling conductors, clashing conductors and corrosion of clamps supporting distribution service mains. Western Power's wood pole failure rate is ten times worse than the average wood pole failure rate of similar utilities in the eastern states. The Western Power network is considered to be a significant cause of bush fires and distribution service main clamp deterioration has been the cause of at least two fatalities. The network condition has also resulted in worsening supply reliability, which is already low when compared to other networks in Australia.

Western Power has also been affected by the significant increases in the price of high voltage electrical equipment over the period since 2004. These increases are well documented and have affected all electricity transmission and distribution businesses. The mining boom in Western Australia also significantly increased the demand for skilled labour and a number of presenters from Western Power alluded to the difficulty the business had experienced in recruiting and retaining staff.

A further driver for change was disaggregation and the influence of the new Western Power Board. Disaggregation has required the development and implementation of new information technology (IT) systems to replace the legacy systems inherited from the aggregated business and initially shared with the other disaggregated business units. In addition the new Western Power Board, comprising mainly non-executive directors with private sector experience, has required the business to review its business practices and develop and implement initiatives to improve its efficiency and effectiveness. This was the genesis of the One Step Ahead program discussed in Section 3.3.

5.4 WESTERN POWER'S RESPONSE

Western Power has responded to the above challenges in a number of ways.

- It has developed a number of different program delivery mechanisms in response to its resourcing challenges. The most noteworthy of these has been the development of alliance partners, where both risk and responsibility are shared by Western Power and the alliance partner. Two major alliance agreements have been signed. The alliance partners, who were selected on the basis of a credentials presentation and competency assessment, get paid direct costs plus a profit margin, while the downside risk to the partner is lower than under a more traditional contracting arrangement. An advantage of the alliance agreements is that they give Western Power direct access to specialised project management and construction skills not available in house. Overall we consider that the new project delivery mechanisms developed over the first regulatory period have substantially increased the quantity of works that Western Power is capable of delivering and has had other upside benefits, but these have come at a significant cost. Such costs were probably unavoidable in the booming economy that existed over the first two years of the AA2 period. However, the existence of these alliance agreements and other longer term contracts will likely make it more difficult for Western Power to fully take advantage of lower costs that would probably be available to it using alternative approaches to project delivery that might now be available as a result of the current economic downturn.

- Western Power has largely centralised the management of its works program through the development of specialist program delivery teams for major work areas. High volume preventive maintenance activities such as asset inspection and vegetation management have been outsourced to specialised contractors. These activities do not have a directly measurable impact on short term supply reliability and are therefore most likely to be affected by a reallocation of resources. Use of dedicated external contractors mitigates this risk. It also facilitates the use of less skilled personnel, who are trained only in a single specialised activity.

- Program management teams now actively measure contractor output and audit the quality of contractor work. This has closed a significant gap that existed at disaggregation where there was little central monitoring of the work done within the individual cost centres. Major program delivery contracts are now coming up for review and there is every indication that the lessons learnt from the first contracting round are being actively addressed.

- A new Estimating Centre has been put in place. While there are indications that its impact on normal day-to-day operations has to date been limited, we think this has been because of the initial focus of the centre was on the preparation of the expenditure forecasts that underpin the Proposed Revisions and also because of the development of accurate cost estimates for major high profile projects like the mid west augmentation. We are confident that, over time, the Estimating Centre will become a more integral component of Western Power's project and program development process and that this will stimulate a significant improvement in the quality of expenditure management. We are particularly encouraged by the proposed new requirement to ensure that project cost estimates are regularly "refreshed" throughout the project development process.

- A new customer information system has been developed and implemented, but development of information systems to support asset and works management has been problematic. Notwithstanding this, Western Power's presentation on the development of information systems impressed and we are confident that the impediments to the development of a new asset and works management system have been identified and addressed. This is not to suggest that expenditure on the development of asset and works management information systems over the AA1 regulatory period has been as efficient or effective as it should have been.

- Western Power's organisation structure has evolved to provide greater focus on management of outputs and improvement of business processes. Key changes have been the merger of the Field Services and Works Delivery divisions to form a single Service Delivery division in July 2007 and the formation of an Enterprise Solutions Partner in September 2008. While the review has not examined these changes in detail, they appear to reflect an evolutionary change in Western Power's business culture.

5.5 AA1 EXPENDITURE OUTCOMES

Western Power's expected actual[26] capital and operational expenditures over the AA1 regulatory period compared to the forecast expenditures at the time that the AA1 access arrangement was approved is shown in the table below. The expected actual expenditures are taken from Western Power's AA2 access arrangement information[27] while the forecast expenditures have been taken from the Authority's final decision on the AA1 access arrangement[28]. These forecast figures have been escalated to June 2009 dollars using the CPI escalators provided by Western Power in its AA2 access arrangement information.

Table 2: AA1 Expenditure Outcomes

	AA1 Decision Forecast	AA1 Expected Actual	Increase
Transmission Capital Expenditure			
Growth	548.96	919.05	67%
Other	123.92	148.42	20%
Total	672.88	1,067.47	59%
Distribution Capital Expenditure			
Growth	517.43	894.82	73%
Other	393.73	609.97	55%
Total	911.16	1,504.79	65%
Transmission Operational Expenditure			
Total	204.69	225.33	10%
Distribution Operational Expenditure			
Total	631.71	776.45	23%
Total Expenditure			
Growth	1,066.39	1,813.87	70%
Non-growth capital	517.65	758.39	47%
Operations	836.40	1,001.78	20%

It can be seen from the above table that:

- Western Power's total growth related capital expenditure over the AA1 period was 70% greater than forecast. This was driven by increased customer driven demand for new connections and high load growth on the network. In seeking approval for this additional expenditure, Western Power management advised its Board that it expected to earn a return on this expenditure through the investment adjustment mechanism.

- Non-growth capital expenditure was also above forecast, albeit to a lesser degree. This additional expenditure, which was largely the result of more asset replacements than forecast, was primarily in response to adverse reports from the Office of Energy Safety and the deteriorating reliability of the network. During the AA1 regulatory period, Western Power actively tried to limit its budget overrun on non-growth capital expenditure as this expenditure was not subject to the

26 Due to the timing of Western Power's AA2 Proposed Revisions the expected actual expenditures for the AA1 regulatory period comprise actual expenditures for 2006/07 and 2007/08 and budgeted expenditures for 2008/09.

27 *[AA2] Access Arrangement Information Appendix 1, Capital and Operating Expenditure 2009/10 to 2011/12*, Western Power, September 2008. See Table 5.1 (p.65), Table 7.1 (p.111), Table 6.5 (p.96); and Table 8.5 (p.156).

28 *Final Decision on the Proposed Access Arrangement on the South West Interconnected Network,* Economic Regulation Authority, 2 March 2007. See Table 34 (p.91); Table 38 (p.93); Table 16 (p.62) and Table 18 (p.64).

investment adjustment mechanism and would not start earning a return until it was rolled into the RAB at the beginning of the AA2 regulatory period.

- While operational expenditure was also above the forecast, the overrun was significantly lower in relative terms than either category of capital expenditure. Asset inspections and vegetation management are two major components of operational expenditure. We believe that substantially higher volumes of asset inspections and vegetation control are now being undertaken than before the AA1 regulatory period, indicating that the centralised management and outsourcing of these functions may be producing efficiency gains[29].

Western Power's ability to respond to the pressures that it faced during the AA1 regulatory period was also constrained by the fact that it is regulated by a revenue cap rather than a price cap. In the eastern states, transmission utilities are generally regulated by a revenue cap while distribution utilities, which also operate the subtransmission networks[30], are regulated by a price cap. Had Western Power been subjected to a price cap, its total revenue during the AA1 period would have been higher due to the fact that sales were higher than assumed during the AA1 regulatory review. These additional revenues may have allowed it to increase the level of asset replacement.

5.6 REGULATORY AND NEW FACILITIES INVESTMENT TESTS

One issue that emerged during this review has been a lack of rigour in the assessment and evaluation of some capital expenditure projects. Chapter 9 of the Code requires that every major transmission network augmentation with an estimated cost greater than $15 million and every major distribution network augmentation with an estimated cost greater than $5 million must be subjected to a regulatory test[31], either within, or outside of the access arrangement approval process. Irrespective of whether or not the test is conducted within or outside the access arrangement approval process there must be:

- a description of each major augmentation;
- a statement by Western Power that in its view, each proposed major augmentation maximises the net benefit after considering alternative options;
- a public *consultation; and*
- *a statement by the Authority as to whether or not the regulatory test had been satisfied.*

Notwithstanding the fact that growth related capital expenditure during the AA1 period is expected to exceed the Authority's approved forecast by almost $750 million or 70% in real terms, there have to date been only two regulatory test applications and these have all been for projects that will not be implemented during the AA1 period and which therefore are not included in the anticipated expenditure overrun. The key component of the regulatory test analysis is the evaluation of the net benefits of alternative options. In conducting our review of relevant projects as described in Section 4, we were unable to find evidence that options analyses had been undertaken in the rigorous or quantitative manner required for a regulatory test assessment. While the Authority had determined

29 We note that the lower increase in operational expenditure may in part be due to changes in capitalisation policies, which would also account for part of the higher capital expenditures. We have not analysed or quantified this.

30 The subtransmission network in the eastern states includes the zone substations and the lines feeding them, which generally operate at 33 kV or 66 kV. On the Western Power network the 132 kV system currently performs both a transmission and subtransmission function. As the 330 kV network develops further, the 132 kV system will increasingly be relegated to a subtransmission role.

31 These thresholds applied at the time the Code became effective in November 2004. The thresholds for major transmission and distribution network augmentations were increased to $30 million and $10 million respectively in 2008. It is likely that only 330 kV network augmentations and projects requiring the construction of longer 132 kV lines will now be subject to regulatory test review. Distribution network expenditure tends to be incremental and we think individual distribution projects with an estimated cost greater than $10 million are unlikely to arise.

that a formal regulatory test was not required for projects committed to prior to the commencement of Western Power's first access arrangement (i.e. 1 July 2007), we would have expected Western Power to be guided by the requirements of Chapter 9 of the Code in determining the level of rigour to be applied when developing its business cases for large projects. However, selection of a particular option appeared often to be based on a planning study that identified the need for reinforcement and a qualitative and somewhat intuitive assessment of different options assuming a single growth scenario. The assessment of the net benefit of different alternatives is the key component of the regulatory test and if this is not undertaken in a rigorous manner then the objectives of the test as described in clause 9.1 of the Code are undermined.

In addition the regulatory test thresholds that apply under the Code are effectively significantly higher than would apply under the National Electricity Rules, applying elsewhere in Australia. This is primarily because zone substation and associated 132 kV upgrades are classified as transmission upgrades under the Code, whereas under the National Electricity Rules such augmentations would be generally classified as distribution and therefore be captured by the lower distribution system augmentation thresholds.

We note that clause 9.14 of the Code provides that projects included in an access arrangement capital expenditure forecast need not undergo a regulatory test. However, in practice, most large projects that are included in an access arrangement application have not been developed to the stage where a regulatory test could be meaningfully applied[32]. Hence, we do not believe that it should be assumed that a project is deemed to have passed a regulatory test simply because it has been included in the capital expenditure forecast that forms the basis for an approved access arrangement and consider that application of a regulatory test under the provisions of clauses 9.10-9.14 of the Code should be the exception rather than the rule.

Closely aligned with the regulatory test is the NFIT, which determines the extent to which a project can be included in the regulatory asset base after commissioning. The NFIT is described in clauses 6.52-6.55 of the Code. Clause 6.71(b) of the Code allows Western Power to seek pre-approval of the NFIT and Western Power has a requirement that pre-approval be obtained for all major augmentations before the project is committed to proceed. Notwithstanding this we could find no procedures for the submission of NFIT pre-approval applications and it appears to us that there is some confusion within Western Power as to what is required. To date there has been only two applications for pre-approval of the NFIT.

5.7 DISCUSSION

The overall impression we gained from this review is that, as an organisation, Western Power is progressively and successfully addressing the structural and organisational impediments to efficient governance and expenditure management. However, this conclusion is not based on an audit but on a review of information selectively provided to us by Western Power. As indicated in Section 5.1, this information tended to focus on what is currently happening and what is planned for the future, rather than what went on in the past. Evidence, anecdotal or otherwise, generally obtained from sources other than Western Power, could indicate that conclusions based on a superficial examination of information made available for this review, might not be entirely accurate. For example:

- A report in the West Australian newspaper of February 2, 2009 stated that in January 2009 a Western Power contractor had erected a power pole in the middle of the second ladies' tee at Pemberton Golf Club during a single phase to three phase overhead line upgrade, without any warning or discussion with the

[32] A regulatory test can only be applied once alternatives have been evaluated and a preferred option selected. In the project development process this only occurs at the point where a project is ready for business case analysis. Most large projects included in a capital expenditure forecast submitted as the basis for an access arrangement application would not have reached this stage of development.

club. The contractor understood that the club had been advised by letter about twelve months earlier, but the club disputed this.

- On 22 April 2009, the Office of Energy Safety publicly disclosed an electrical incident report on a bushfire at Balingup caused by a failure of a Western Power single phase pole on 14 February 2009. The pole had been inspected on 8 January 2009 and reported to be in satisfactory condition. According to the report, the condition of the pole was reported to be better (in that it had more good wood) than reported in its previous inspection in May 2008. The report stated that even if the most recent inspection had correctly identified the pole as being safety critical, this would not have been reported in time for the pole to have been replaced before it failed. It was also reported that two adjacent poles had the same asset number and, although not discussed in the report, we can speculate that the two inspection reports may have related to different poles. There are two other reports on the Office of Energy Safety's web site on bush fires in January or February 2009 that were initiated by Western Power's distribution assets.

- In late 2008 the Office of Energy Safety conducted a distribution wood pole management audit. In respect of pole inspections the audit report[33] indicated that at the time of the audit the number of poles being inspected annually was consistent with a four-year inspection cycle. The audit re-inspected a random sample of poles recently inspected as part of the inspection program and found that the above ground inspections had been well done. However, the audit found deficiencies in current practices for inspecting the condition of poles below ground level. As a result of these deficiencies, pole deterioration below ground level might not be detected and poles that should be classified safety critical could be passed as safe.

  Western Power did not raise this issue during the relevant presentation on 17 April. However it conceded there was a problem in its AA2 maintenance expenditure forecast by increasing the forecast for distribution pole inspections from $7.6 million in 2006/07 to $17.9 million in 2009/10 to "enhance the ground line inspection process to include either full excavation of the soil around the base of the pole to a depth of approximately 500 mm in line with current Australian practice, or to introduce an alternative pole strength testing technique currently under trial"[34]. The audit report also identified a number of other deficiencies in Western Power's distribution pole management practices.

- We believe the NCR wind-back program described in Section 3.5 will not, of itself, meet the stated program objectives and on its own will have little impact on network reliability. This is because zone substation transformer failures are relatively rare and, should a failure occur, the claimed improvement in reliability will not be achieved because of other network constraints and the availability of alternative operating responses. This does not imply that funds should not be provided for reliability improvement projects but does indicate that such initiatives could be better planned and targeted.

- We have also been advised that Western Power has only recently started to use aluminium cable for underground distribution. While copper cable is arguably easier to install and has other technical advantages it is significantly more expensive and for this reason the use of aluminium cables has been standard practice in the industry for many years. We think Western Power has been very slow to adopt this technology.

We are mindful of the fact that it would be dangerous to draw conclusions on the basis of a few possibly isolated issues when other documents that we have reviewed and the

[33] *2008 Distribution Wood Pole Audit Review*, EnergySafety, Western Australian Department of Commerce, May 2009
[34] Western Power, *Revised Access Arrangement Information for the Network of the South West Interconnected System,* 1 October 2008, p128.

information provided at the presentations provided a much more positive impression. Notwithstanding this, all these examples are relatively recent, with some of the system failures occurring in 2009.

6. CONCLUSION

The nature of this review and the limitations on its scope make it difficult to reach firm conclusions regarding Western Power's performance during the AA1 regulatory period largely because, while the conclusions from our desk top review of relevant documents provided by Western Power, and our discussions with relevant staff were generally positive, specific events brought to our attention, including those identified in Section 5.7, indicate that the reality is more negative. Without a well planned audit, which is outside the scope of this review, we are unable to assess whether these events relate to isolated one-off problems or are indicative of more systemic issues.

We can however make some general comments:

- Western Power's distribution network is in relatively poor condition due to a legacy of underfunding that lasted for at least a decade prior to disaggregation. Its ability to respond to this situation is, and will continue to be, constrained by the funds made available to it. We are satisfied that all available funds are needed and could potentially be effectively used.

- In this environment the issue is how well the use of the available funding is optimised rather than how much funding is required. In particular, we think there is scope to better utilise the available capital expenditure. Examples of expenditure that we think would have been better applied in other areas are the installation of transformers at the Wells Terminal Station with a rating higher than required to supply the potential load and the use, until very recently, of copper distribution cables.

- We think there is also scope for a more rigorous options analysis of large capital expenditure projects. The regulatory test requirements are indicative of the scrutiny expected and the input applied into ensuring an optimal decision is made for the mid-west transmission augmentation project, to which the regulatory test was applied, far exceeds that for any other project we have reviewed. We are not arguing that it is realistic to apply this level of scrutiny to all projects but note that collectively Western Power's total capital expenditure is much higher than that on one large project. Hence we believe that a higher level of scrutiny than is currently routinely applied is indicated. We also note that the thresholds for the regulatory test set out in the Code will not capture many Western Power projects that would be subject to a regulatory test review under the National Electricity Rules, which apply elsewhere within Australia.

- Our review of the control of large one-off capital expenditure projects indicated a number of process weaknesses that appeared to be systemic. These included poor cost estimating, a failure to adequately define the project scope during the development phase and the inclusion of excessive contingency provisions in funding increases approved late in the implementation phase.

- The relatively low overrun in operational expenditure when compared to the AA1 approval forecast, notwithstanding the significant expansion in asset inspection and vegetation management activities, indicates that centralised program management of the routine maintenance effort is resulting in significant cost efficiencies. However the ongoing occurrence of relatively frequent and high profile asset failures raises questions about how well this inspection and maintenance work is being implemented in practice. It may be that the poor condition of the distribution network is simply overwhelming the available resources and that more time is required to get on top of the problem.

- We were particularly concerned at the evidence of contractor overcharging revealed in the OSA business case. While the overcharging identified in the business occurred prior to the start of the AA1 period, the lack of any evidence of a decisive response by Western Power indicates that these practices may have extended well into the early part the AA1 regulatory period. We believe much tighter contract management processes are now in place and think it highly unlikely that this overcharging is continuing.

- In our review of the information provided on large transmission projects, we noted that Western Power is now including accrued interest in its reports on final project outcomes and this was confirmed at the presentations. However, we also noted from the information provided to support the Proposed Revisions that Western Power is proposing that work in progress as at 30 June 2009 be included in the opening asset base for the AA2 regulatory period. We did not explore why Western Power is reporting accrued interest in its final reports on project outcomes, but note that if work in progress is capitalised then accrued interest on projects under construction should not also be capitalised.

Overall, it is clear that at the beginning of the AA1 regulatory period there were significant weaknesses in the management and governance of Western Power's expenditure. These weaknesses would have affected both the effectiveness of this expenditure, in the sense of the extent to which it was optimally targeted to achieve Western Power's strategic objectives, and its efficiency, in the sense of the extent to which waste was minimised. While much progress in improving expenditure governance and management has been made over the regulatory period, we believe weaknesses still persist, albeit to a much lesser degree.

We consider that over the AA1 regulatory period the Western Power Board and management have aggressively tried to improve the governance within the organisation and have made commendable progress in this effort. This has been done in an environment where the organisation has faced many challenges including an unprecedented demand for new connections, rapidly rising equipment and labour costs and a legacy of underinvestment in the distribution network that persisted for at least a decade.

The events identified in Section 5.7 indicate that the embedding of process improvements into the organisation is ongoing and far from complete. Improved expenditure management and obtaining more efficient outcomes require a cultural change and experience elsewhere indicates that such change is not implemented easily. This is particularly true where the change involves a shift from a public service culture with its focus on inputs and technical excellence to a commercially driven culture with a focus on outcomes and efficiency.

The main area of weakness, which to a degree we think still persists, is in the management and optimisation of capital expenditure. There is some evidence that better expenditure outcomes would be achieved if technical and engineering factors were subjected to a higher level of economic scrutiny in the assessment of capital expenditure projects. There may also need to be an increased focus in optimising the available capital expenditure to best meet the requirements of the whole organisation even if this means that outcomes are sub-optimal when considered from the perspective of individual projects. This is an area we believe Western Power still needs to address.

We have not seen anything in this review that would indicate that the progress made in the management of capital and operations expenditure during the AA1 period will not continue during the AA2 regulatory period and are confident that where weaknesses in Western Power's management and governance processes are identified they will be proactively addressed.

It was apparent from the discussion during the presentations for this review, that Western Power applied the recommendations of the Tellis Chase report to the preparation of expenditure forecasts for the AA2 period, and particularly when forecasting the cost of large one-off capital projects. We were told that the forecasting effort was led by the newly formed Estimating Centre and the process included the holding of internal estimating workshops to ensure that estimates were based on scenarios that reflected likely regulatory test outcomes and that the projects were fully scoped to ensure that all material costs were included. It is not within the scope of this review to examine the forecasts for individual projects, or the extent to which the assumptions on which individual forecasts are based, were appropriate. However, we do believe that the processes used to produce these forecasts were robust.