Attachment 20.73

SA Power Networks: Capital and operating historical expenditure

October 2014

Contents

1. Purpose

The purpose of this Attachment to the SA Power Networks 2015-20 Regulatory Proposal, is to provide a summary of our historical expenditure in comparison to our forecast expenditure, as required by the National Electricity Rules (**NER**).

2. Capital expenditure

The NER Schedule 6.1.1(6) requires SA Power Networks' building block proposal to contain capital expenditure for each of the past *regulatory years* of the previous and current *regulatory control period*, and the expected capital expenditure for each of the last two *regulatory years* of the current *regulatory control period*, categorised in the same way as for the capital expenditure forecast and separately identifying for each such *regulatory year*:

- margins paid or expected to be paid by SA Power Networks in circumstances where those margins are referable to arrangements that do not reflect arm's length terms; and
- expenditure that should have been treated as operating expenditure in accordance with the policy that SA Power Networks applies in capitalising operating expenditure for that *regulatory year*.

NER Schedule 6.1.1(7) requires SA Power Networks to provide an explanation of any significant variations in the forecast capital expenditure from historical capital expenditure.

2.1 Capital expenditure summary 2005 - 2020

Table 2.1 shows SA Power Networks' total historical net capital expenditure for the period 2005/06 – 2013/14, and the total forecast net capital expenditure for the period 2014/15 – 2019/20.

Table 2.1 Net capital expenditure summary 2005/06 – 2019/20 ($ million, June 15)

Capital	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Replacement	20	30	34	39	46	63	86	93	97	117	134	156	166	169	167
Augmentation	74	60	54	62	65	135	147	143	99	116	146	185	196	186	172
Connections	22	33	30	37	27	25	38	40	33	26	34	36	37	40	42
Non Network	47	35	24	51	45	57	66	62	64	81	149	131	111	123	105
Alternative Control Services	NA	NA	NA	NA	NA	4	4	4	4	13	10	10	11	11	7
Total	**163**	**157**	**142**	**190**	**183**	**284**	**341**	**341**	**296**	**353**	**474**	**518**	**521**	**529**	**492**

SA Power Networks did not have any related party arrangements in respect of capital expenditure for the period from 2005 to the present and does not expect to have any such related party arrangements for the remainder of the current 2010-15 RCP or the 2015-20 RCP.

In addition, SA Power Networks has not incurred any expenditure that should have been treated as operating expenditure in accordance with our capitalisation policies during the period from 2005 to the present and does not expect to incur any such expenditure for the remainder of the current 2010-15 RCP or the 2015-20 RCP.

2.2 Explanation of significant forecast capital variations from historical capital expenditure

In the current 2010-15 RCP, SA Power Networks has undertaken a significant investment program consistent with the AER approved allowances. The capital program was largely focused on augmenting our network ensuring our ability to meet expected demand for Standard Control Services (**SCS**).

SA Power Networks required a significant step increase in augmentation in the 2010-15 RCP compared to the 2005-10 RCP. This was primarily driven by Electricity Transmission Code (**ETC**) changes and forecast spatial demand growth. There was also a step change in replacement due to our requirement to manage the condition of our ageing and deteriorating infrastructure. This necessitated refurbishment or replacement of defective assets to maintain the safety, quality, reliability and security of supply in delivering SCS.

During the period from 2001 to 2010, the focus of Information Technology (**IT**) investment was on establishing the major business systems that underpin SA Power Networks' business today. The peak in the IT investment in the early 2000s (Figure 1) corresponds to our entry into the National Electricity Market (**NEM**) which necessitated the implementation of the Customer Billing and Information System 'Open Vision' (**CIS OV**) and the Full Retail Contestability applications for customer support and compliance with NEM regulations. The other two major systems implemented during that period were the Outage Management System (**OMS**) and the Geographic Information Systems (**GIS**) that support critical network control and field services business functions. Continuing investment in the SAP Enterprise Resource Planning system (implemented in the late 1990s) was also required to meet growing demands for IT support of back office processes.

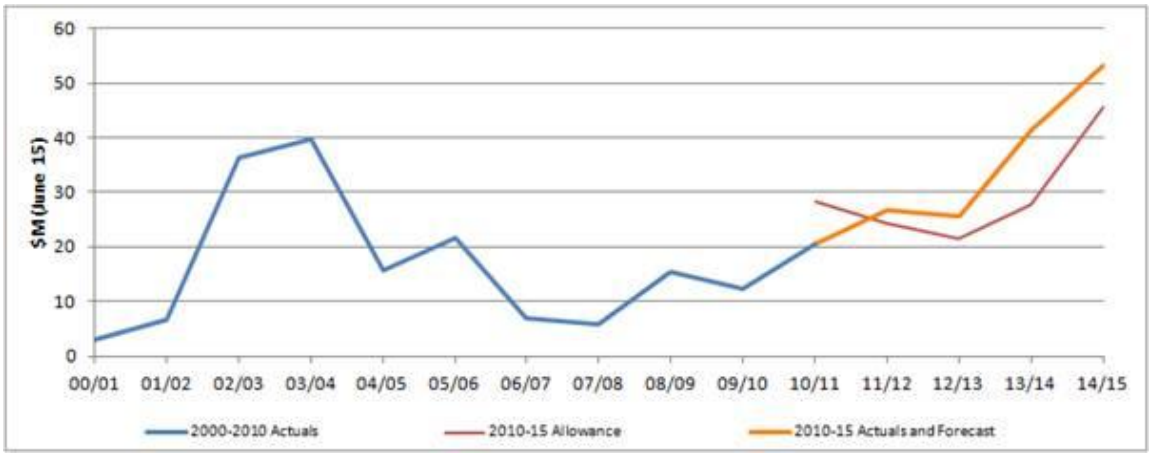

Figure 1: Historic IT Capital Expenditure and 2010-15 Reset Allowance, real $ (June 2014). The peak in the early 2000s corresponds to the implementation of the Customer Information System and related FRC applications[1]

During the 2010-15 RCP, the focus moved to technology refresh and incremental enhancements to the IT capabilities established in previous periods. In practice, faster than expected changes in the business environment triggered key organisational changes and imposed greater than expected reliance on IT capabilities. Additional investments were required in the works management, asset management, customer facing and regulatory systems due to changed customer expectations, regulatory obligations and increased business demand.

[1] The data behind the graphs were sourced from the SA Power Networks Regulatory team and the IT Commercial; these data will be further verified and confirmed to ensure consistency with financial reports.

With regard to Alternative Control Services (**ACS**), the 2010-15 RCP expenditure has been below allowances as the majority of metering connections were negotiated services. Note that the AER allowance has been assumed for 2014-15.

In the 2010-15 RCP, SA Power Networks has invested prudently and efficiently in network and non-network assets, evidenced by reduced capital expenditure arising from lower capacity upgrades and customer connections requirements. Furthermore there is a recognition that circumstances are likely to change during a regulatory period and where it is prudent to defer capital expenditure whilst still meeting service standards then DNSPs are encouraged to do so. This results in a lower regulatory asset base and lower costs to consumers in the long term.

The main drivers impacting the forecast capital expenditures compared to the current RCP, are identified below.

Demand driven augmentation

For the 2015-20 RCP, demand driven augmentation is forecast to decline. Demand driven augmentation will be limited to small areas of growth, and includes committed projects where the network has exceeded the planning criteria in 2014 and a small number of security projects where the preliminary Regulatory Investment Test-Distribution (**RIT-D**) has demonstrated a positive market benefit. The forecast five year demand driven augmentation expenditure is a reduction of $114 million (June 15) compared to the current RCP actual/forecast expenditure.

Asset replacement

In the 2010-15 RCP asset replacement trended upwards. The 2015-20 RCP sees a continuation of this trend due to the condition of our ageing network. The majority of SA Power Networks' assets were installed in the 1950s, 1960s and early 1970s. Our program of asset inspections on power line assets during the 2010-15 RCP has identified that a significant volume of asset replacement work is required to meet our regulatory obligations relating to the provision of *standard control services* and the maintenance of the safety of our *distribution system.* These obligations derive from a number of sources including:

- section 60 of the *Electricity Act*;
- the requirements of our Distribution Licence;
- the ESCoSA approved Safety, Reliability, Maintenance and Technical Management Plan (**SRMTMP**);
- the various requirements relating to the maintenance of network assets referred to in the Electricity (General) Regulations (in particular, Section 12 of Schedules 1-4);
- the ESCoSA-set service standards for reliability; and
- Chapter 5 of the NER (in particular, clauses 5.2.1 and 5.2.3 of the Rules which require us to maintain and operate the network in accordance with relevant laws, the requirements of the Rules and good electricity industry practice, and the power system performance and quality of supply standards, set out in Schedule 5.1).

The forecast five year asset replacement expenditure is an increase of $309 million (June 15) compared to the current RCP actual/forecast expenditure.

Safety (augex)

The 2015-20 RCP also sees a significant increase in safety related augmentation expenditure driven by our proposed Bushfire Mitigation program and programs developed in response to our Customer Engagement Program.

The proposed Bushfire Mitigation program is in response to the recommendations of the Victorian Bushfire Royal Commission (**VBRC**) and the resulting Powerline Bushfire Safety Taskforce (**PBST**) which reviewed the outcomes of the VBRC. The Bushfire Mitigation program reflects our duty to take reasonable steps to ensure that our distribution system is safe and safely operated (Section 60(1) of the *Electricity Act*) and to maintain and operate our facilities in accordance with good electricity industry practice (NER Clause 5.2.1(a)). These duties require SA Power Networks to have regard to objectively determined standards of safety (i.e. what would a reasonable and prudent electricity distribution system operator faced with the same conditions and circumstances, as apply to SA Power Networks do, to ensure that the distribution system is safe and safely operated and is maintained and operated in a manner that is consistent with the degree of skill, diligence, prudence and foresight expected from Australian electricity distribution system operators).

During SA Power Networks' Customer Engagement Program collaborative workshop on undergrounding, customers raised significant concerns regarding risks associated with our power lines and road safety and bushfire safety. Recognising the prohibitive costs of widespread undergrounding, they indicated a preference for reducing community safety hazards by a targeted approach to undergrounding power lines and poles at high risk locations. Further Willingness to Pay research confirmed customer concerns for community safety. The highly targeted programs for undergrounding for road safety purposes and undergrounding power lines in HBFRAs are in response to our Customer Engagement Program to address customers' preferences for improved community safety.

The forecast five year safety related augmentation expenditure increases by $304 million (June 15) compared to the current RCP actual/forecast expenditure.

Information Technology

Based on our experience in the 2010-15 RCP, it has become clear that SA Power Networks needs to move away from the incremental change to business processes and supporting systems (which has occurred over many years), to a more integrated 'end state' approach to data, systems, processes and people which is linked to service outcomes and business objectives.

The proposed investment in network infrastructure and customer facing developments, combined with significant changes to people, data, systems and processes, warrants an integrated approach to business improvement. In the 2015-20 RCP, there will be increased investment in both our recurrent and non-recurrent programs of work.

The increase associated with the recurrent program of work for the 2015-20 RCP is due to the following key factors:

- increased support requirements for key applications and infrastructure owing to the management of the enlarged applications environment;
- strengthened demand for systems reliability, IT support and user training arising from the increased reliance on IT based information and systems;
- increased use of mobile computing across the organisation;
- the level of required software upgrades and equipment renewals in line with supplier recommendations, reflecting the upgrade requirements of the additional hardware and applications installed during the current RCP; and
- compounding effects of the introduction of new business systems and capabilities on the IT support requirements, including additional data storage, network capacity, disaster recovery and integration with the existing systems.

The increase associated with the non-recurrent program of work is to support the business delivering outcomes for customers and owners as follows:

- new technology requirements to meet the changes in the external environment (eg changes in the consumer preferences, regulatory changes, environment changes, technology changes) and the internal SA Power Networks environment (eg changes in the business operating model). Key focus areas include:
  - improved SA Power Networks asset management capability required to ensure long-term sustainable performance and condition of the assets, including the associated improved visualisation capability of spatial asset data;
  - increased expectations of SA Power Networks' customers regarding levels of service and quality of information. The IT implications include improved customer data management capabilities and the provision of customer self-service reporting options;
  - progressive rollout of smart ready meters and other demand-side participation technologies which require increased data storage, processing and analysis capabilities;
  - building new capabilities for our workforce to deliver on additional data requirements, customer expectations and the increased work program;
  - increased level of cyber security threats that require greater investments in the IT security systems and processes to ensure corporate and operational systems and information are protected in an event of an attack; and
  - implementing enterprise enabling technologies to support new capabilities;
- changes to the IT operating model required to support the increased volume of capital work; and
- managing the risk of our older core systems such as replacing CIS OV and upgrading our Enterprise Resource Planning system (**ERP**).

The forecast five year non-network IT expenditure increases by $192 million (June 15) compared to the current RCP actual/forecast expenditure.

Alternative Control Services

Prior to the 2010-15 RCP SA Power Networks had no Alternative Control Services (**ACS**) expenditure. The 2015-20 RCP sees a significant step change in ACS expenditure compared to actual expenditure in the current period. The key step changes are:

- changes to the AER's F&A[1] for SA Power Networks, comprising the reclassification of Type 5 metering services, meter installation services, and energy data services as ACS;
- the metering-related impact of the introduction of capacity tariffs as described in Chapter 14 of the Proposal; and
- the introduction of 'smart ready' meters on a new and replacement basis.

Notwithstanding these significant drivers of change in the metering area, SA Power Networks is still required to comply with the requirements of the Responsible Person role contained in the NER, and other technical and regulatory requirements. In addition to meeting these requirements, SA Power Networks' metering services aim to ensure that relevant expenditure is prudent and efficient, and focussed on ensuring that our metering equipment:

- is safe and accurate;
- supports our network pricing and tariff strategies;
- supports our network load management objectives and strategies; and
- is reasonably capable of efficiently supporting current and expected future relevant market and/or customer requirements.

[1] AER, *Final framework and approach for SA Power Networks RCP commencing 1 July 2015*, April 2014

Increased expenditure is necessary to ensure SA Power Networks meets technical and regulatory requirements. The forecast five year ACS expenditure increases by $24 million (June 15) compared to the current RCP actual/forecast expenditure.

3. Operating expenditure

NER Schedule 6.1.2(7) requires SA Power Networks' building block proposal to contain operating expenditure for each of the past *regulatory years* of the previous and current *regulatory control period*, and the expected operating expenditure for each of the last two *regulatory years* of the current *regulatory control period*, categorised in the same way as for the operating expenditure forecast.

NER Schedule 6.1.2(8) requires SA Power Networks to provide an explanation of any significant variations in the forecast operating expenditure from historical operating expenditure.

3.1 Operating expenditure summary 2005 – 2020

Table 3.1 shows SA Power Networks' total historical operating expenditure for the period 2005/06 – 2013/14, and the total forecast operating expenditure for the period 2014/15 – 2019/20.

Table 3.1 Operating expenditure summary 2005/06 – 2019/20 ($ million, June 15)

Operating	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Network Operating	20	22	22	24	25	26	26	28	32	33	37	39	41	43	45
Network Maintenance	64	60	71	77	74	99	105	122	119	128	143	144	148	152	154
Customer Services	19	19	20	21	22	26	26	26	27	27	28	30	35	36	38
Corp. costs and other operating	40	35	38	49	48	64	66	62	67	67	78	85	92	93	93
Alternative Control Services	NA	NA	NA	NA	NA	6	7	6	6	7	10	10	21	22	23
Total	**144**	**137**	**152**	**171**	**169**	**222**	**230**	**244**	**251**	**263**	**296**	**309**	**337**	**347**	**352**

3.2 Explanation of significant forecast operating variations to historical operating expenditure

SA Power Networks has consistently demonstrated our ability to prudently and efficiently manage the delivery of SCS and ACS during the current RCP. This is evidenced by the number of significant challenges we have encountered, some out of our control, that have directly impacted on the operating costs of providing these services. In particular:

- Guaranteed Service Level (**GSL**) payments have been extraordinarily high due to the increase in frequency and severity of extreme weather events across the current RCP;
- the breaking of the 'millennium drought' in 2010 had a substantial impact on our vegetation management program. An AER-approved pass-through application in July 2013, for the 2012/13 to 2014/15 period, has not completely offset the increased costs that we have incurred as we work to ensure that we have a compliant vegetation management program by 30 June 2015; and

- the volume of solar photovoltaic (**PV**) system installations has far exceeded the forecast take up volumes, largely driven by the State Government *Feed-In Tariff* legislation. This has resulted in increased customer services costs in relation to processing and administering the installations.

Despite the materially increased costs associated with these items, by the end of the 2010–15 RCP, we forecast that our total operating expenditure will be in line with the total AER allowance for the period. Operating expenditure has followed an upward trend consistent with the allowance. This trend will continue in the forthcoming RCP as we continue to meet our regulatory and other obligations.

The main drivers impacting the forecast operating expenditures compared to the current RCP are identified below. Note that SA Power Networks proposes 2013/14 as the efficient revealed base year, under the base-step-trend forecasting approach.

Base Year cost adjustments
SA Power Networks has proposed base year cost reductions of $35 million (June 15) for expenditures of an unusual nature that impact longer-term efficient costs. The most significant of these are self-insurance costs ($16 million), which have been reduced to the five year average, and metering reclassification ($11 million) for the reclassification of Type 5 and 6 metering from SCS to ACS.

Legal and regulatory obligations
SA Power Networks has identified legal and regulatory step changes of $105 million (June 15) over the next RCP. This relates largely to an increase in asset inspections to meet regulatory obligations for pole inspection and to align with industry standards for asset inspection frequency in bushfire risk areas. Additional operating costs are also expected to be incurred due to changes to energy laws and regulations, most notably for the introduction of smart ready meters.

Capital program impacts
SA Power Networks has identified step change expenditure of $70 million (June 15) in the next RCP for operating/capital expenditure trade-offs and impacts of the proposed capital expenditure program. The most significant expenditures relate to the efficient migration of SA Power Networks' mobile radio network to the SA Government Radio Network and an uplift in information technology operating expenditure for the maintenance and support of new technologies and systems.

Customer driven initiatives
SA Power Networks is proposing step change expenditure of $42 million (June 15) over the next RCP to implement customer-driven initiatives identified in the course of its engagement with electricity customers in support of the development of its Regulatory Proposal.

Output growth
SA Power Networks has forecast additional expenditure of $47 million (June 15) in the next RCP for growth in its network, customers and workforce size.

Real price growth
SA Power Networks has forecast real increases of $61 million (June 15) in input labour, materials and services above CPI for the next RCP, based on independent expert advice. Most notable of these costs are increases related to the negotiated Enterprise Bargaining Agreement for employees.

Debt raising

SA Power Networks has forecast debt raising costs of $27 million (June 15) for the next RCP, based on independent advice of transaction costs a benchmark efficient energy network service provider would be expected to incur.

Alternative Control Services

Metering operating expenditure in the next RCP will be impacted by two key changes, being the AER's F&A for SA Power Networks which reclassifies Type 5 metering services and energy data services as ACS, which have a material impact from 2015/16, and the metering-related impact of the introduction of capacity tariffs, which has a material impact from 2017/18. The total forecast 'step' increase for ACS in the next RCP is $56 million (June 15).