EnergyAustralia's

2009-14 Regulatory Proposal

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AER Public Forum - 30 July 2008

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Agenda

- EnergyAustralia’s Network
- Our Proposal
- Regulatory context
- Drivers – replacement, meeting demand and reliability
- Managing demand and energy efficiency
- Pricing
- Conclusions

EnergyAustralia's Network

- **What does the network do**
  - Obligation to connect
  - Provides capacity to meet peak demand, but
  - Sufficient available capacity does ***not*** drive demand

- **Unique Features:**
  - Transmission and distribution network, supports TransGrid
  - Underground feeders
  - Time to renew and replace large number of assets
    - Distribution centres
    - Zone substations and sub-transmission cables

EnergyAustralia’s Proposal

- **$8.66 billion capital investment**
  - Start of large scale network renewal
- **Large and Challenging proposal**
  - Build 42 new zone substations and de-commission 32 zone substations
  - Replace 1,263 panels of 11,000 volt switch gear
  - Replace 155 km of 33,000 volt gas cable
  - Replace 141 km of 132,000 volt oil cable
  - Connect an average 17,300 new customers to the electricity network each year

Regulatory Context

- **First national distribution determination follows three state decisions 1995,1999 and 2004**
- **Previous decisions characterised by:**
  - "Cost – x" framework
  - Management objectives - extract capital efficiency
  - No service incentives
  - Result – large deferred capital, without regard to long term prudence or service outcomes
- **Service standards at risk, leading to new network regulation**

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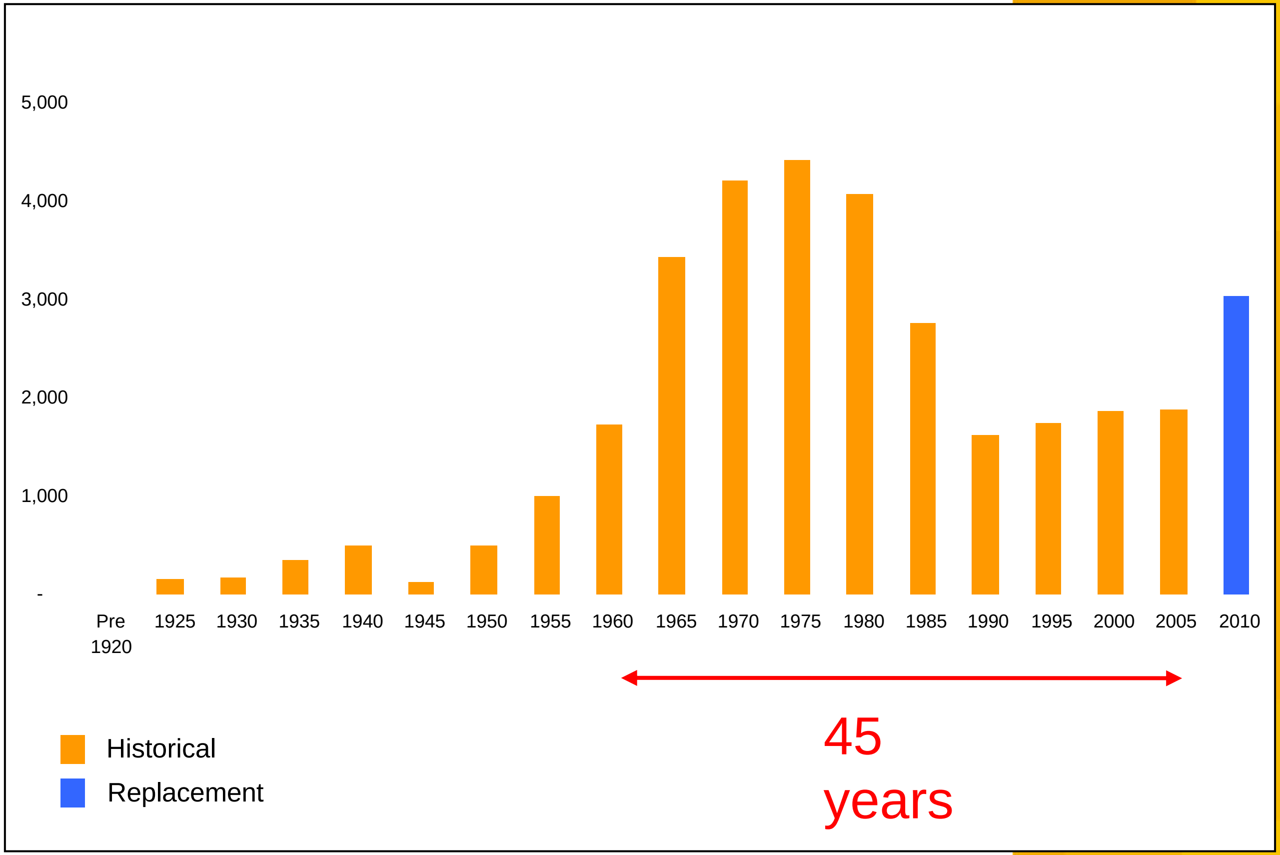
Drivers of EnergyAustralia's Proposal

- Time to renew large parts of our electricity network
- Meeting increased demand for power
- Improve reliability



Past Capex (Real Replacement Cost)

(Figure 1.2)

Drivers

- **Replacement program**
  - Electricity network has undergone several periods of growth
  - Post war expansion and late 1960s and 1970s economic expansion

- **Meet increasing demand for power**
  - Peak residential demand growing at 3.7% driven by increasing use of air conditioners
  - 58,000 air conditioners installed in homes on our network each year – required to meet that demand

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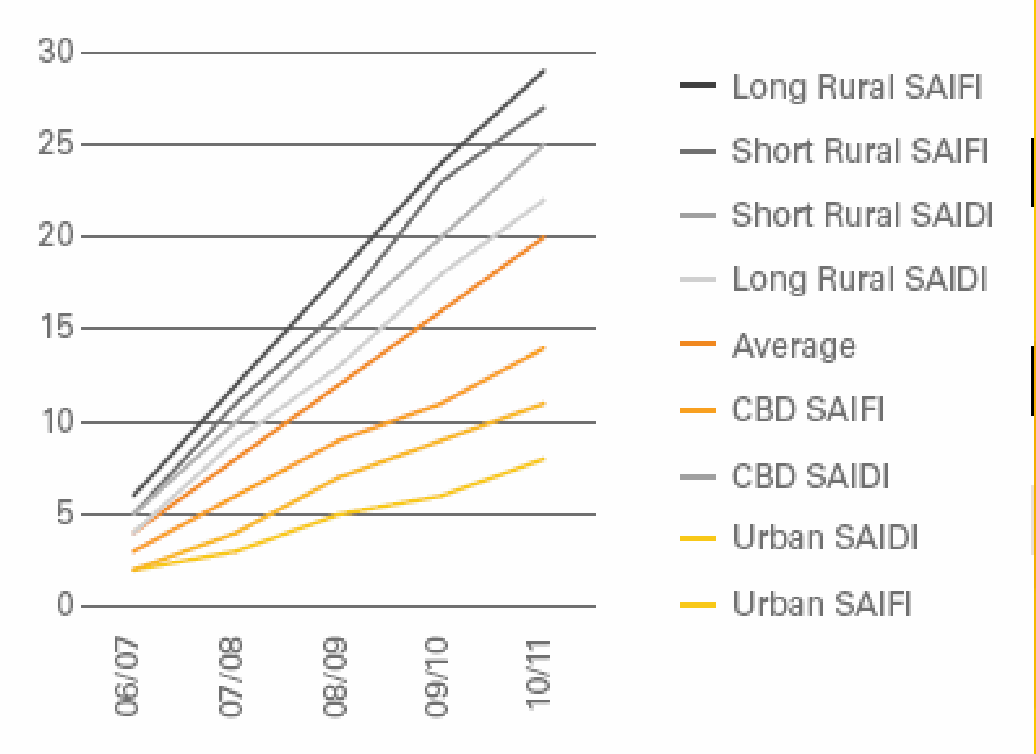
Drivers - improve reliability

- Mandatory Licence conditions
  - **No incentives in previous regulatory framework for service**
  - **NSW Licence condition in force from 2005**
- Targets – average 25% improvement in reliability by 2011
  - **Overall targets must be met**
  - **Individual feeders must meet performance conditions**
- **Planning Standards**
  - **N-2 planing for the Sydney CBD**
  - **N-1 for most other areas**



Managing demand and energy efficiency

- **Early movers on demand management**
  - 400,000 first generation of smart meters 200,000 time of use tariffs
  - 5% drop in their electricity use in the peak compared to shoulder periods – conservation and shifting of electricity use
  - Deferred more than $50 million of capital investment through DM.
  - Given away or installed 3 million energy efficient light bulbs, 500,000 shower timers and collected and destroyed more than 1,400 old inefficient fridges, provided almost 1,000 rebates for new pool pumps.
  - Opened a $3 million state of the art energy efficiency centre

- **EnergyAustralia is driving advanced metering infrastructure for new customer enablement**
  - $10 million trial of 7,000 advanced smart meters
  - Requires regulatory and policy support
  - *Outside this proposal*

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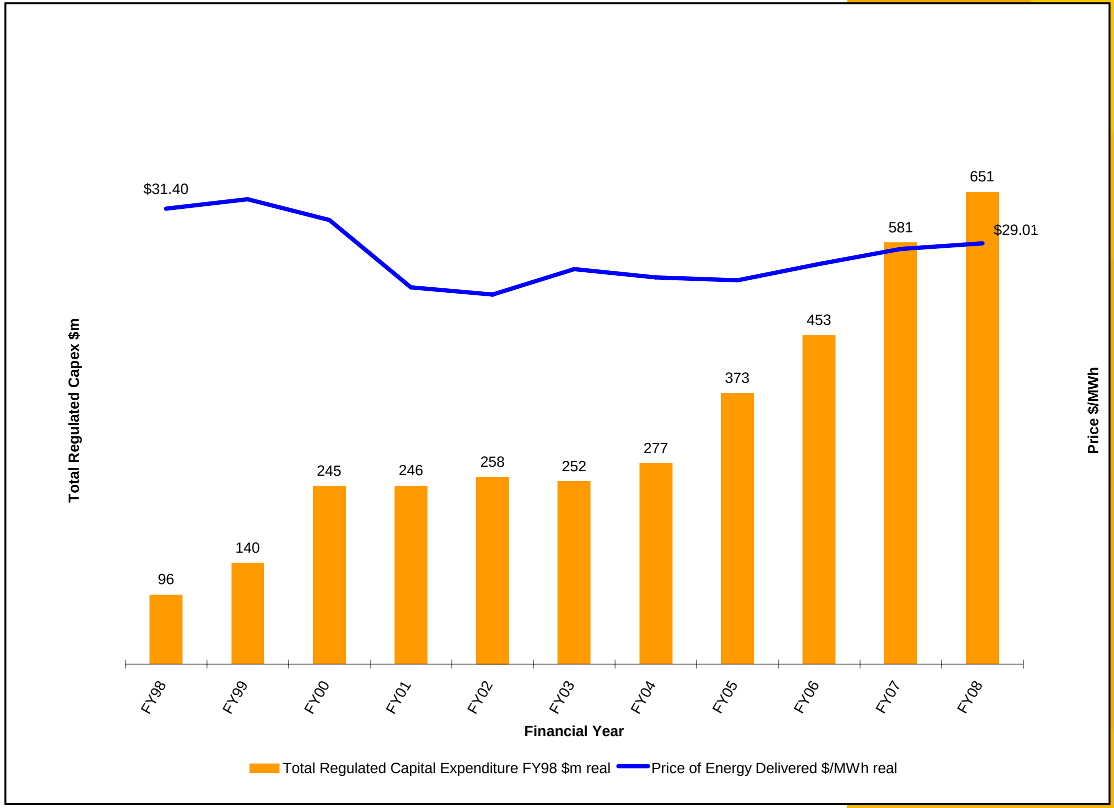
Pricing

- $8.6 billion capital investment for safe and reliable supply
- Typical household will see $2/week increase in 2009
- Real prices have declined – lower than 10 years ago
- Capital investment in last 5 years has not been reflected in the price



Regulated Capex vs Price of Energy Delivered

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Conclusion

- **Transitional rules**
- **Both parties “feeling our way” – with good co-operation**
- **New decision making framework – key questions for the AER are limited to whether the proposal reasonably reflects:**
    1. the efficient costs of a prudent DNSP in the circumstances
    2. a realistic expectation of demand forecasts and cost inputs
- **AER must allow the DNSP to recover the efficient costs of achieving the capital objectives**

(Figure 1.3)

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2009-14 Regulatory Proposal

Geoff Lilliss
Executive General Manager - Network

AER Public Forum - 30 July 2008

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Presentation Structure

1. **Overview**
2. **Regulatory Environment**
3. **Capital investment**
    - Driver
    - Forecast methodology
    - Area Plans, Replacement Plan, etc
4. **Real Cost escalation**
5. **Operating costs**
    - Capex / opex tradeoff
    - System opex
6. **Outcomes**
7. **Delivery & efficiency**
8. **Pass-through**

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Regulatory environment

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Regulatory Environment

Capital & operating objectives:

1. **Meet or manage demand**
2. **Comply with regulatory obligations**
3. **Maintain quality, reliability and security of services**
4. **Maintain reliability, safety and security of distribution network**

New investment criteria:

1. ***AER must accept proposal if it is satisfied that the forecast reasonably reflects the efficient costs of a prudent DNSP in the circumstances***
2. ***Proposal must reflect a realistic expectation of demand forecasts and cost inputs***
3. ***AER must allow the DNSP to recover the efficient costs of achieving the capital objectives***

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Regulatory Proposal Summary

	FY10	FY11	FY12	FY13	FY14
Capital Expenditure (FY09 $bn real)	1.58	1.60	1.88	1.83	1.76
Regulatory Asset Base ($bn nominal)	8.22	9.56	10.87	12.39	13.79
Revenue Building Blocks ($bn nominal)					
Return on Capital	0.80	0.96	1.12	1.30	1.49
Return of Capital	0.08	0.10	0.13	0.15	0.15
Operating Expenditure	0.58	0.61	0.67	0.71	0.75
Tax	0.04	0.08	0.09	0.10	0.11
Annual Revenue Requirement	1.50	1.75	2.00	2.27	2.49
X Factor					
Distribution	-29.41%	-10.43%	-10.43%	-10.43%	-10.43%
Transmission	-8.42%	-15.77%	-15.77%	-15.77%	-15.77%

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Regulatory Proposal - Summary

Contributions of IPART decision to distribution P-nought

(Figure 1.1)

Capital expenditure

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EnergyAustralia's Capital Base

Transmission system (km)	821
Transmission Substations	40
Sub transmission (km)	3,807
Zone substations	176
Distribution substations	29,471
High voltage overhead (km)	10,285
High voltage underground (km)	6,770
Low voltage overhead (km)	21,556
Low voltage underground (km)	6,225
Poles	498,191

	2004	2009
Distribution RAB value	$4,116 m	$7,229 m
Transmission RAB value	$636 m	$989 m

Opportunity to invest is now

- Windows for work on network are getting smaller
- Significant increase in subtransmission capacity required

(Figure 5.6)

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Key Forecast Principles

Capex	Opex
Plans target compliance with DWE licence conditions	Base year for opex forecast costs is 2006-07
Spatial forecast based on 2005-06 summer with high level review to ensure consistency with summer 2006-07	Opex forecast is impacted by total system capital program
Spatial forecast relies on global peak demand growth forecasts for years 7-20 (Area Plans)	Non-system opex does not include the costs associated with Retail separation
Replacement forecast is driven by condition and risk assessment	Maintenance forecast based on condition and risk assessment analysis
Capital program will be adjusted for impact of tariff DM and non-tariff DM	Key non-system property & IT proposals have received management approval
AMI roll-out is not included in forecast capex program (only seed capital)	Incorporates ongoing apprentice program of 160 new apprentices per annum
Real cost escalation (above inflation) is applied to both capex & opex forecasts	

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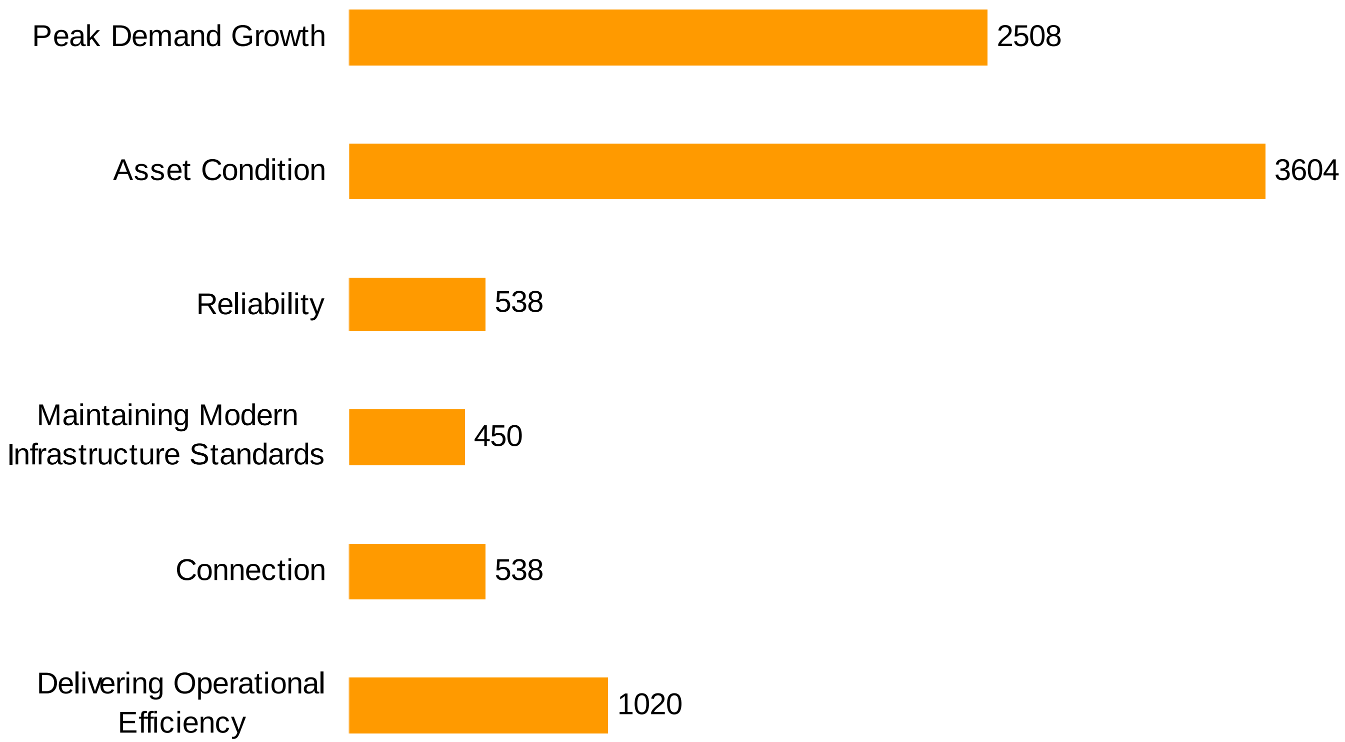
Capex by Driver



(Figure 4.11)

FY09 $m Real

Capex Forecast Methodology

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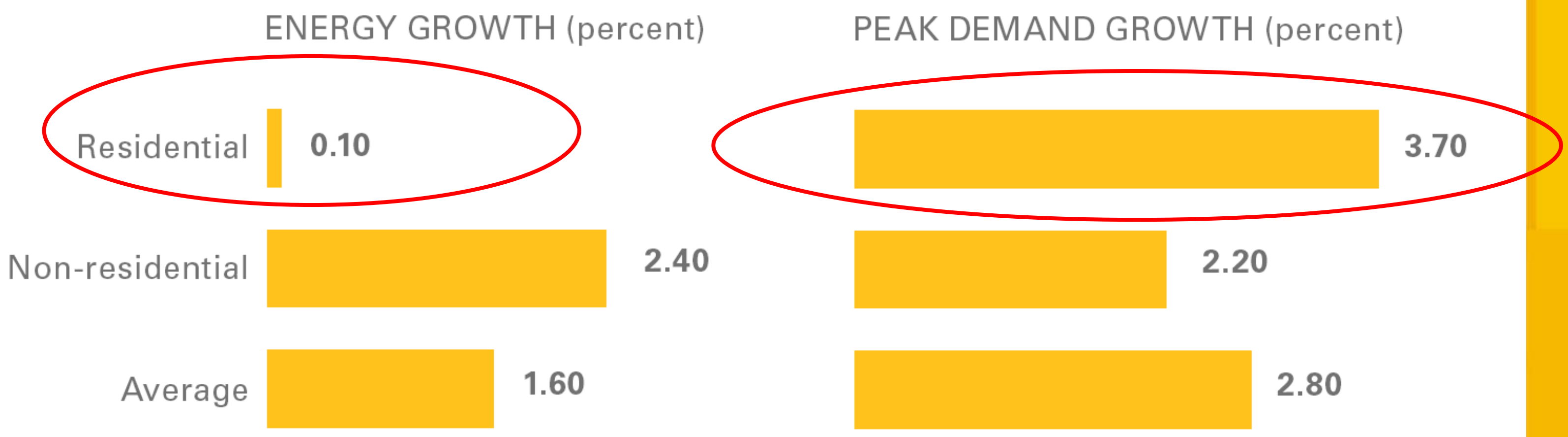
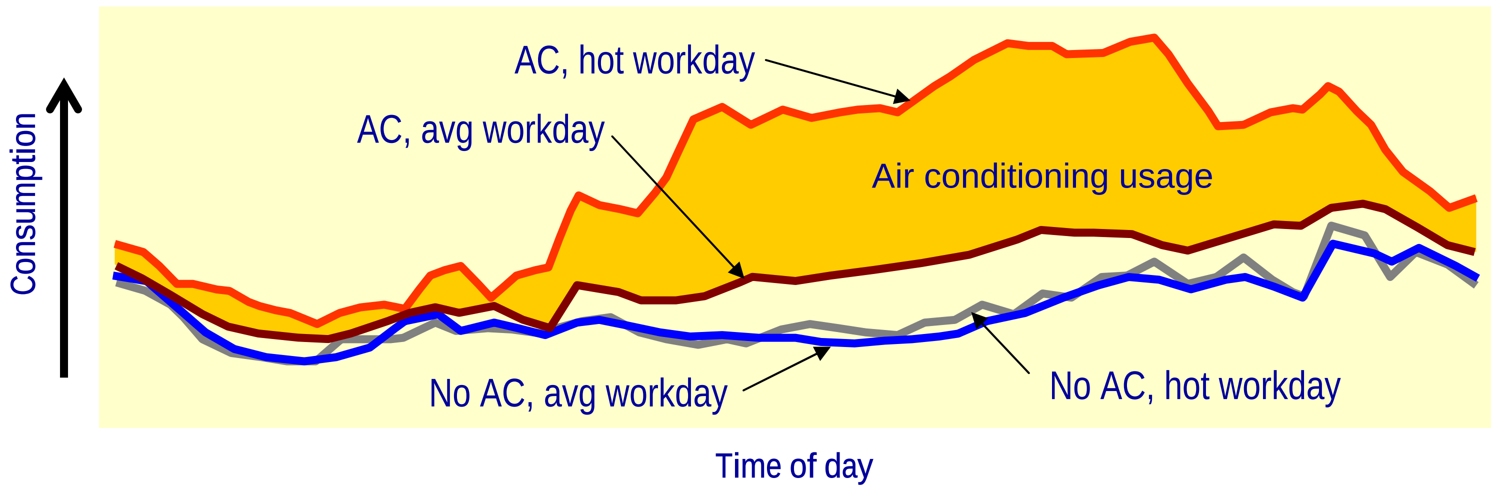
Key challenge – peak demand

Disconnect between peak demand and energy growth



(Figure 4.1)

Air conditioning penetration – 59% June 2008, 78% June 2014



Key challenge – licence compliance

Design, Reliability & Performance licence conditions:

Schedule	Name	Summary
Schedule 1	Design Planning Criteria	Establishes minimum network back up capacity and limits for load at risk that planners must meet when planning augmentations of the network.
Schedule 2	Reliability Standards	Mandates minimum performance levels for average performance in each feeder category.
Schedule 3	Individual Feeder Standards	Mandates minimum performance levels for individual feeder reliability for each category of feeder.
Schedule 4	Excluded Interruptions	Outlines interruptions that are allowed to be excluded from statistics reported against Schedules 2 and 3.
Schedule 5	Customer Service Standard	Defines standards for maximum interruption durations and frequencies for individual customers. Customers who experience performance beyond these standards are eligible for financial compensation.
Schedule 6	Major Event Day	Describes the methodology for calculation of Major Event Days which are one of the exclusions allowed under Schedule 4.
Schedule 7	List of Metropolitan Areas	A list of all those suburbs considered to be metropolitan areas for the purposes of the Schedule 5 customer standards.

(Table 4.1)

Investment strategy

Principles:

1. **Least cost outcomes**
   - Regulatory requirement
2. **Maximise synergies for replacement / augmentation / other**
3. **20 year long term view of investments**
   - Sustainable level of investment rather than sub-optimal short term fixes

In practice:

- **Extension of 132kV in areas of high load density**
- **Optimal size zones**
  - 100MVA in areas with high load density
- **Where there is existing infrastructure or geographical issues, 66kV and 33kV can be lowest cost options**
- **Choose least cost between “greenfield” and “brownfield” options**

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Area Plans

- **A holistic approach to network planning**
  - Applies to strategic investment
- **Area Plans consider longer term (20 years)**
  - Enables EnergyAustralia to choose lowest NPV strategy over longer term
- **Areas based on natural network boundaries**
  - Some have connectivity between regions
  - Legitimate way to consider options within Distribution context
- **28 Area Plans in total – including 3 transmission plans**
  - Based on known network needs
- **Facilitates synergies between major drivers**

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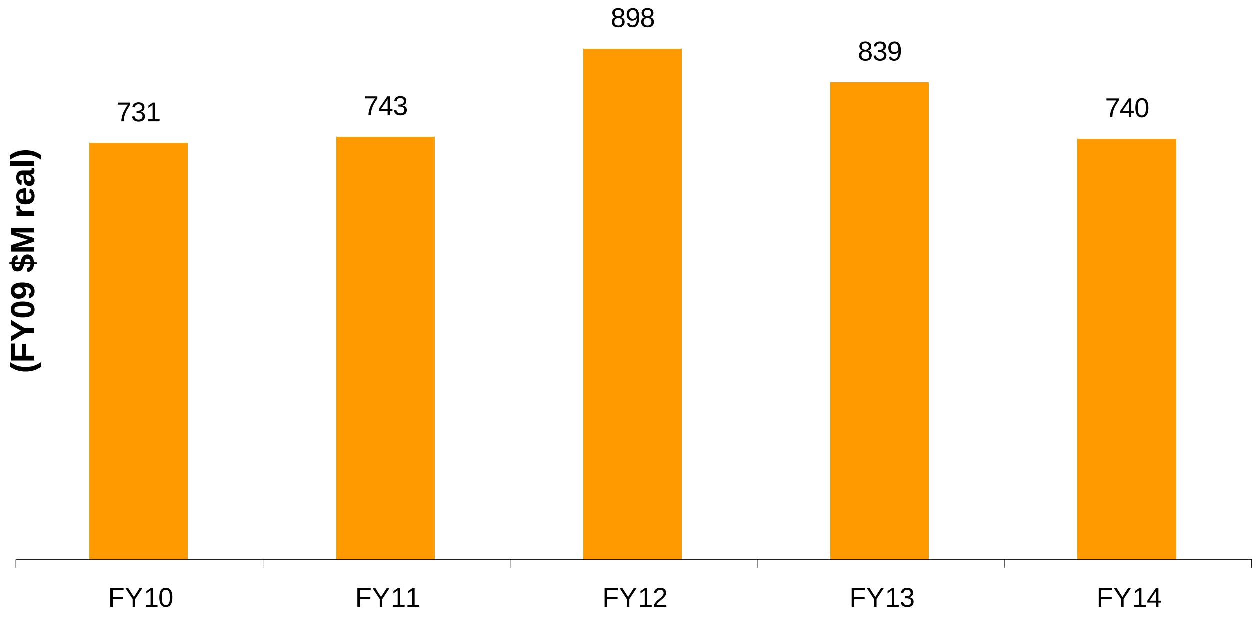
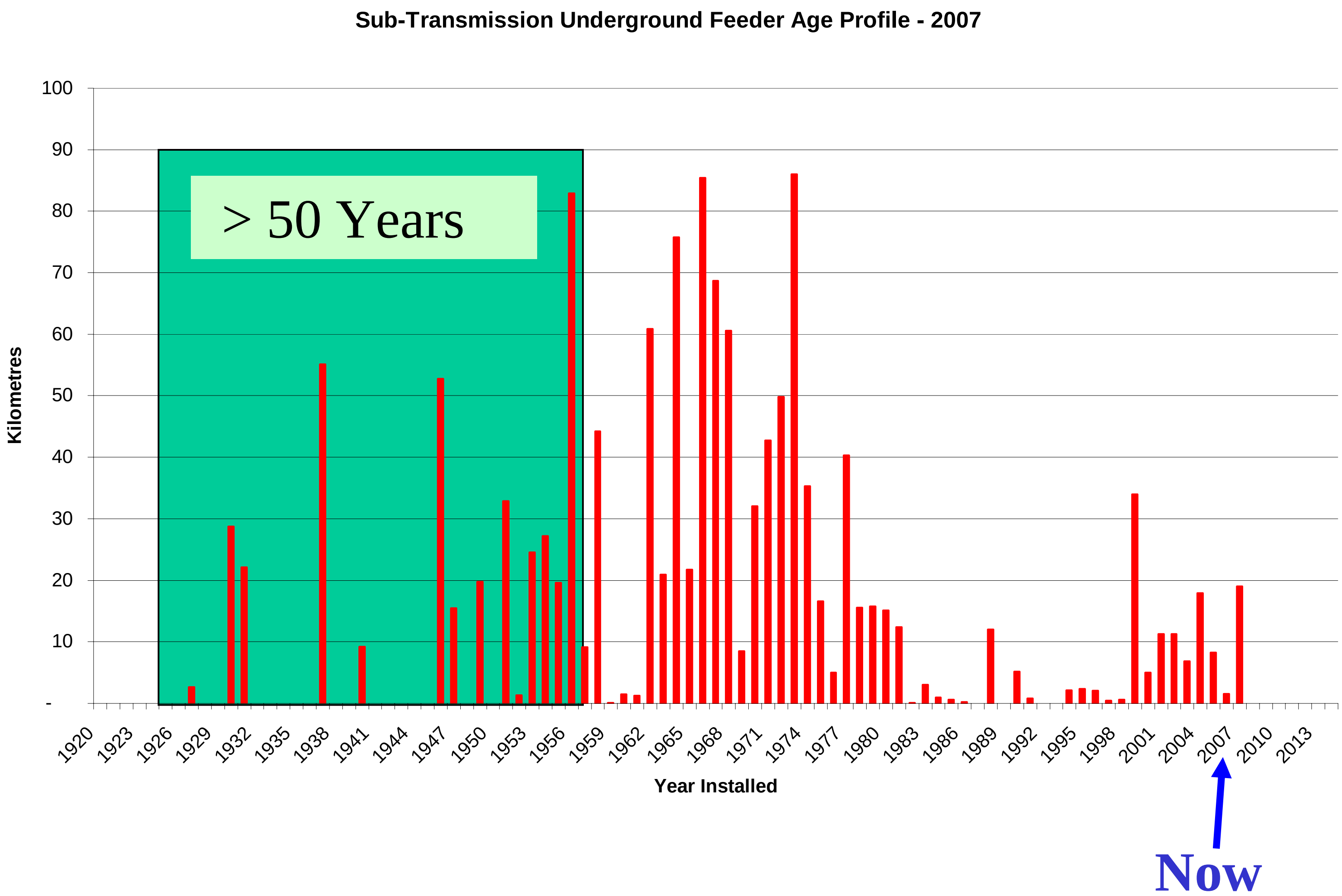
Total Area Plan Capex



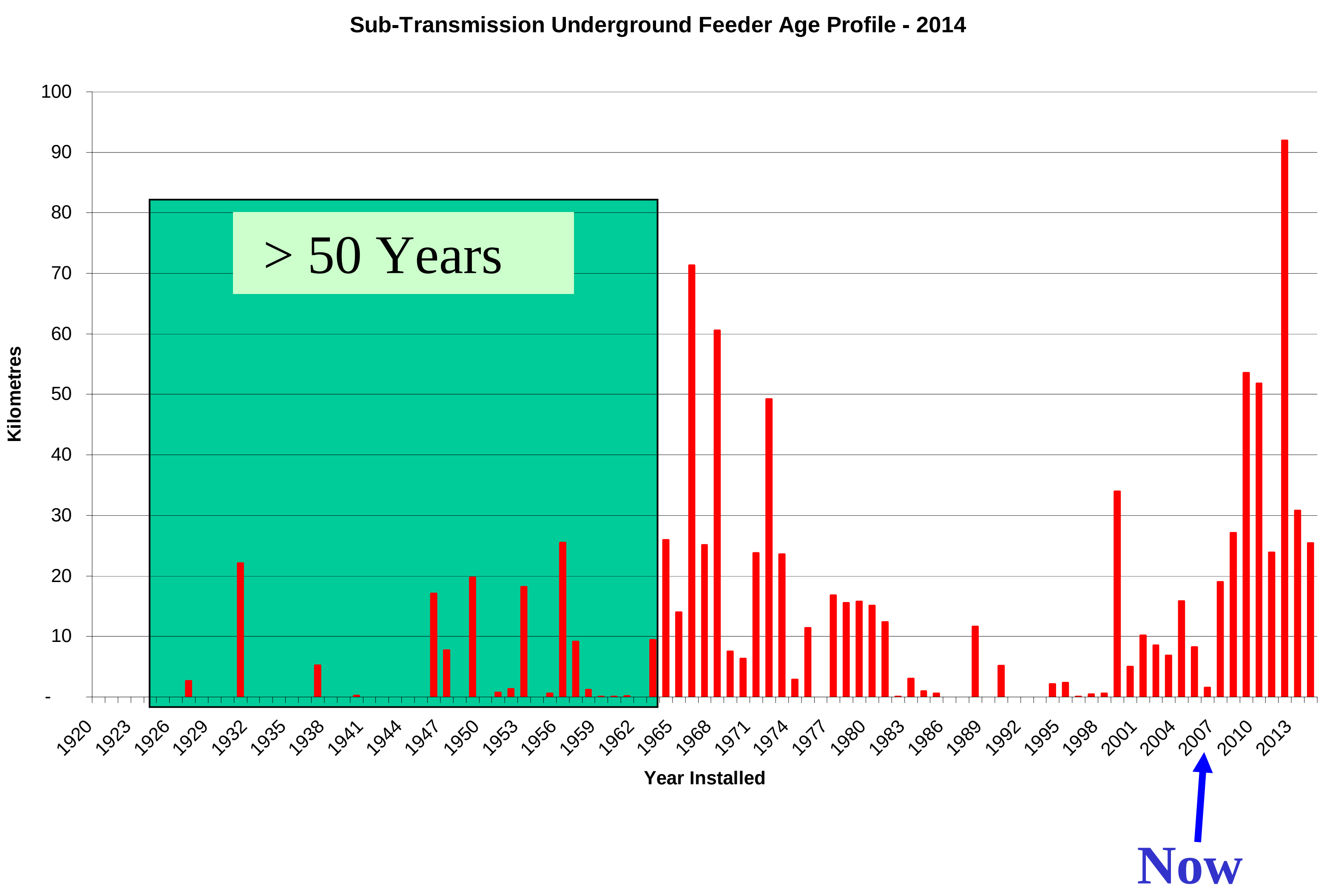
- Total Area Plan capex is $3.9bn over 2009-14
- Includes Subtransmission and Transmission Area Plans
- Area Plan expenditure peaks in this period due to both replacement and licence compliance (by 2014)

Transmission Underground Feeder Age profile - 2007



(Figure 4.6)

Transmission Underground Feeder Age profile – 2014 Forecast



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Replacement Plan

Replacement Plan includes:

1. Replacement needs for all assets below the 11kV busbar
2. Replacement needs for assets above 11kV busbar that do not drive strategic investment (i.e. new zone substation, new subtransmission cable)

Replacement assets **not** included:

- 132kV oil cables
- 33kV gas cables
- 11kV switchgear (strategic)

Programs:

- Planned – proactive programs proposed for 2009-14 period
- Reactive – unplanned replacement as a result of failures

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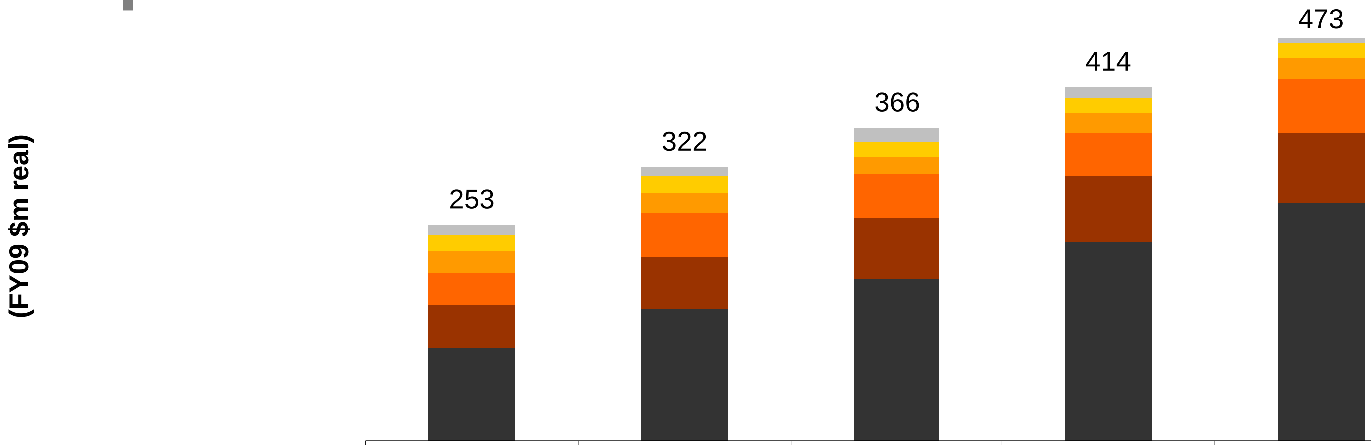
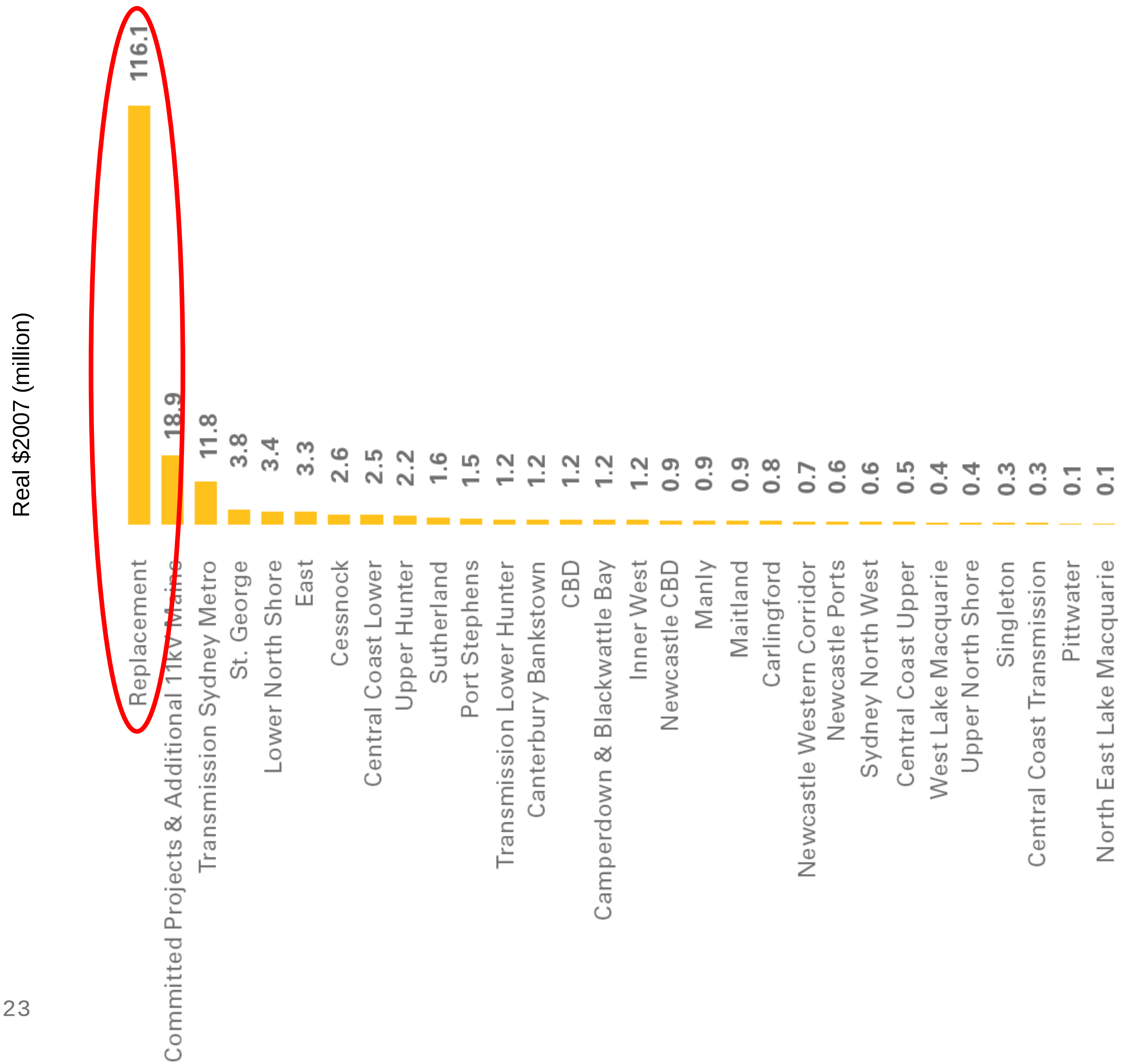
Replacement Plans



	FY10	FY11	FY12	FY13	FY14
	253	322	366	414	473
Other	11	10	15	11	7
Transmission Mains	18	20	18	18	18
Transmission Substation	28	26	21	23	22
Zone Substation	38	50	51	50	65
Distribution Centres	50	61	72	79	81
Distribution Mains	109	155	188	232	279

- **These plans cover component replacement – larger strategic replacement projects are covered in the Area Plans**
- **Step change to higher and sustained level of asset renewal**

Maintenance impacts of capital plans



(Figure 6.3)

Reliability Plan

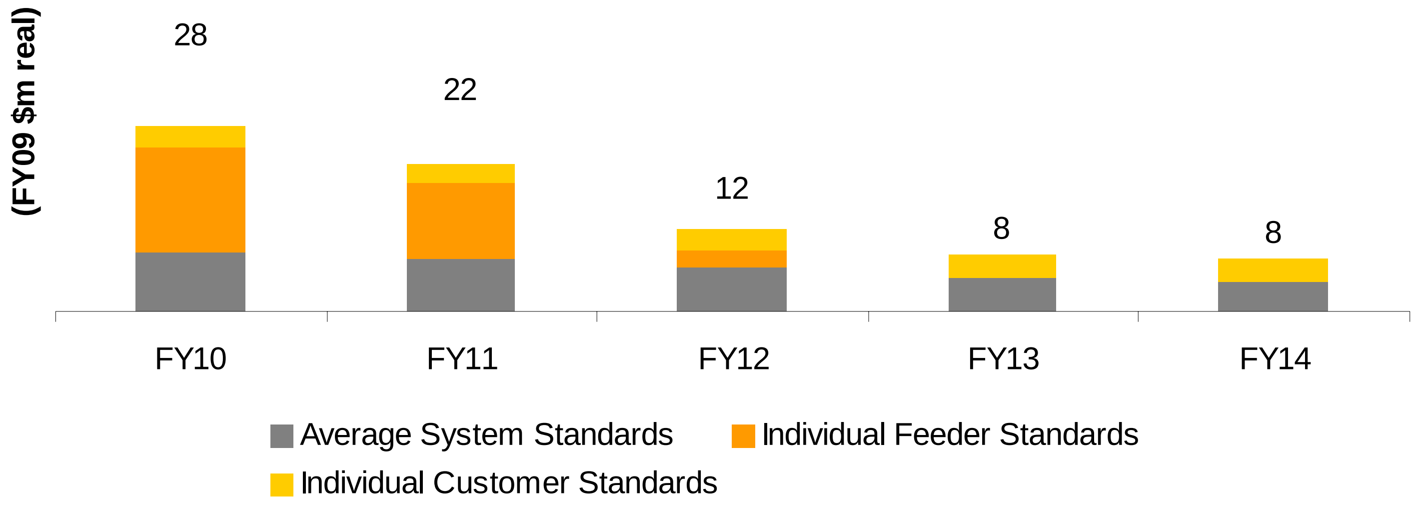
Individual feeder reliability:

1. Analyse where poor performance exists
   - On average, 1% urban feeders and 2% short rural feeders require action
2. Check that other programs do not address this
   - Projects contained in other plans generally are not related to specific feeders, therefore there is no overlap
3. Develop distribution reliability project list

Average feeder reliability:

1. Analyse areas where targets will not be met
   - Probability that targets will not be met increases to 70% in some cases by 2010-11
2. Consider the impact of other programs
   - Extensive work included in other plans provides reliability benefit
3. Identify gaps and implement programs
   - Only gap arises in Long Rural category
     - A project has been designed to address the issue.

Total Reliability Plan Capex

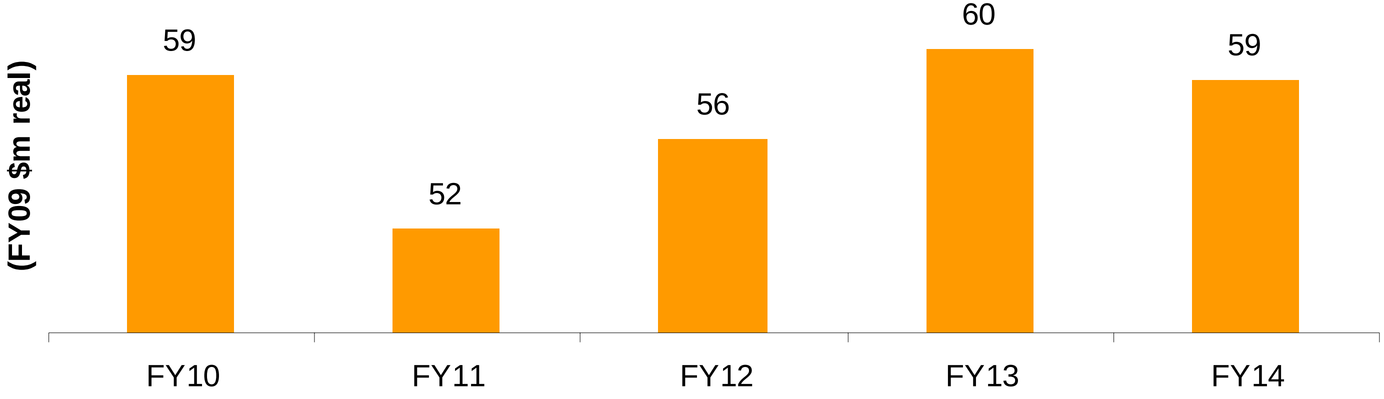


- **Total Reliability capex for the 2009-14 period is forecast to be $79m**
- **Reliability Plan is front end loaded to address reliability gaps**
- **If all outcomes are achieved in 2014, ongoing expenditure should be relatively flat**

Duty of Care Plan

- To ensure that our network meets modern infrastructure standards
- Developed by assessing asset types and using surveys of installed equipment
- Expenditure falls as compliance gaps are filled
- Longer term planning helps avoid non-compliances

- Similar format to Replacement Plan
- Key issues in Duty of Care (09-14):
  1. Asbestos
  2. Fire
  3. Substation security
  4. Network operation security



11kV Plan

Network Development Model used to forecast 11kV requirements

- **Based on licence conditions**
  - N-1 redundancy
  - 80% utilisation by 2014, 75% utilisation by 2019.
  - Load is restorable within 4 hours

- **Uses EnergyAustralia costs and load density to predict future needs of zone capacity and 11kV capacity**

- **11kV investment is divided into three parts:**
  1. Connection cabling
     - connecting distribution centres together
  2. Injection cabling
     - connecting zone substation to distribution network (i.e. injecting capacity into 11kV network)
  3. Interconnection cabling
     - connecting distribution feeders together to facilitate load pick-ups

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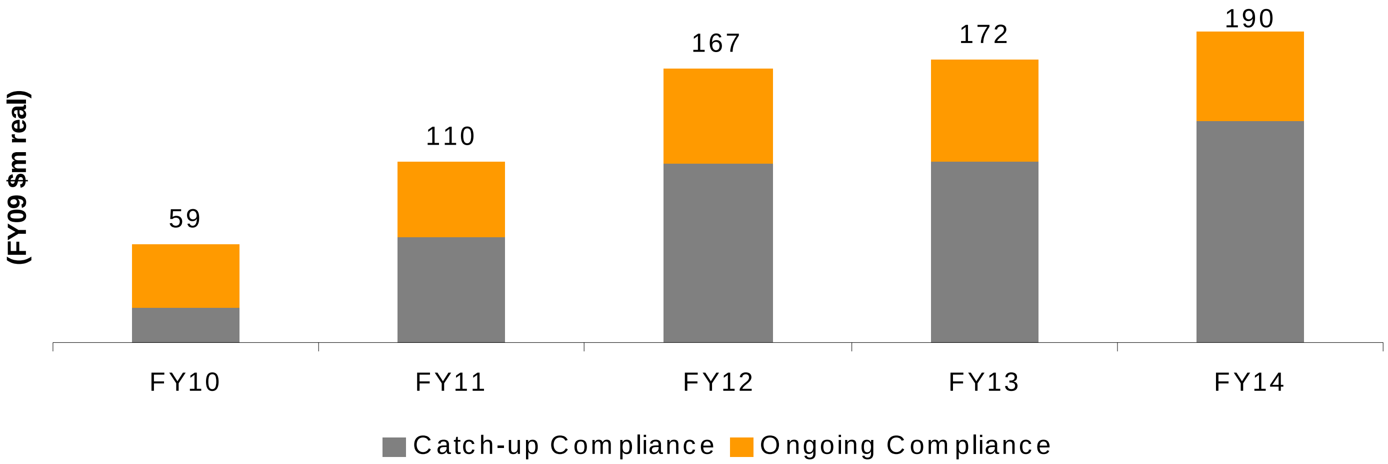
11kV model results

- **EnergyAustralia has exhausted economies of density**
  – Substations are large enough and any larger would become more expensive to distribute energy away from substations

- **11kV network development will become more expensive in future**
  – As load density increases, distribution centre size increases and feeder utilisation falls
  – Smaller length jobs due to density of network
  – High set up costs will dominate cost of work and lead to overall cost increases

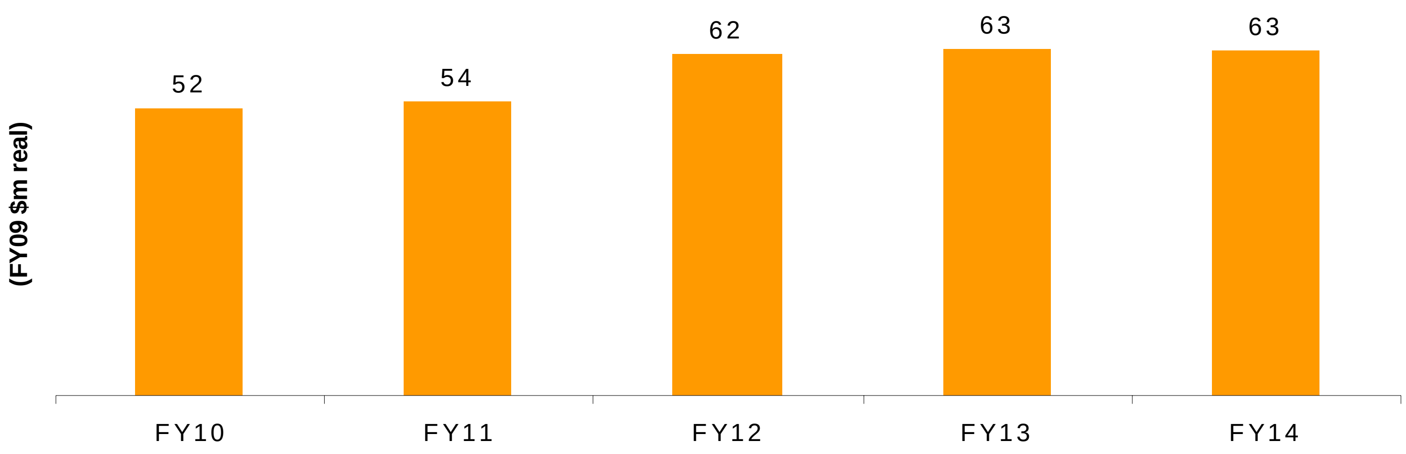
- **Additional major investment is required in the 11kV network to:**
  1. Catch up (to new standards)
  2. Higher ongoing levels of expenditure to keep pace with conditions (as no spare capacity currently exists)



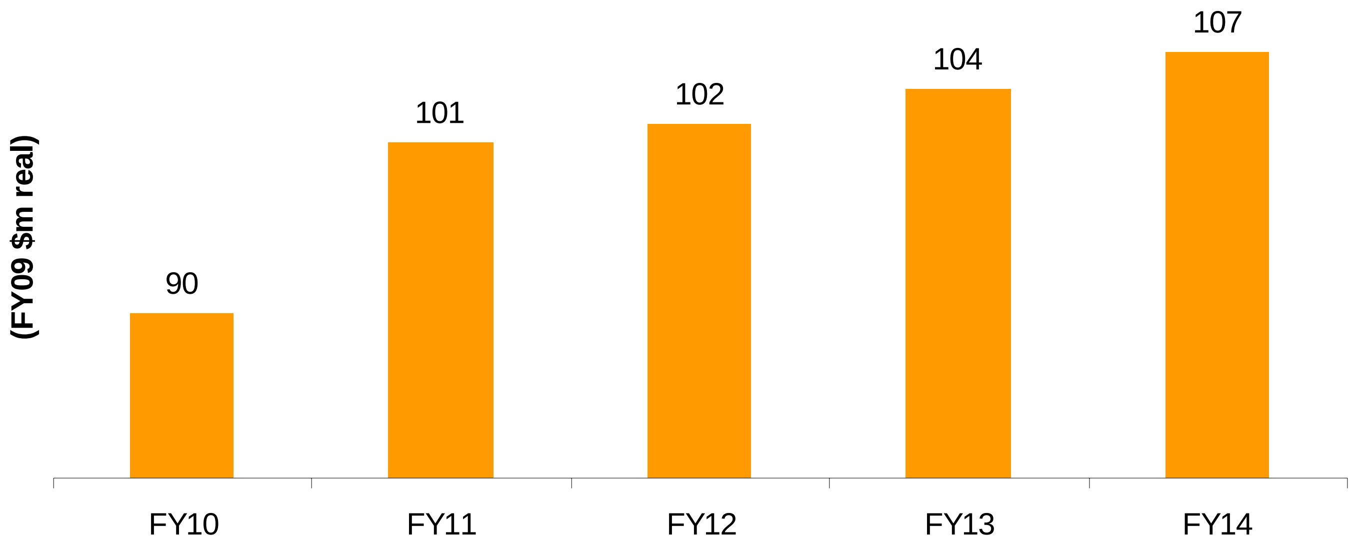
Low Voltage strategy

- **Criteria:**
  - Distribution Substations
    - Planning Based on MDI Data — 100% of cyclic rating
    - Planning Based on Load Survey — 95% of cyclic rating
  - Low Voltage Distributors — 95% of fuse rating

- **Modelled on historic EnergyAustralia costs**
- **Based on known state of the network**
- **Capital proposal includes funds to improve LV data**
- **Implementation of monitoring will enable increased utilisation which will:**
  - defer capital expenditure
  - reduce costs of future load surveys



Customer Connections (EA funded)



- **Industry expert commissioned to produce independent forecast**
- **Independent review of unit rates for key equipment and project types**

3 types of customer connection expenditure:

- Customer funded (currently treated as income)
- EA funded (capex)
- GIS data update (capex)

Business Support Capex

1. IT: All application owners have been consulted in terms of identifying impacts.

   Based on application life-cycle assumptions and looks forward to new initiatives and new data centre consolidation.

2. Property:

   Based on underlying rationale for premises with consistent standards

3. Fleet:

   Based on life-cycle of fleet

Capital Smoothing / Carry Over

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Capital Smoothing

- Smoothing of the capital program in 2009-14 was carried out to provide a deliverable program (smoothing the 2009-12 peak)
- Smoothing was based on analysis of system needs
- Smoothing defers approximately $400 million of capital expenditure, including augmentation and replacement expenditure, from the 2009-14 period to the 2014-19 period

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Explicit adjustments for Demand Management

Methodology

- **Tariff based DM**
  - Strategic pricing study findings used
  - 1.1% reduction in peak demand for certain customers
  - Results extrapolated across customer classes to obtain average expected reduction
  - Impact is approximately $30 million reduction to final year capex

- **Project based DM**
  - Calculate DM impact on growth capex over 2004-09
  - Apply same percentage to determine expected impact in 2009-14
  - Add costs of DM into opex based on historic costs
  - DM calculated to defer up to $53 million from 2009-14 to 2014-19
  - Impact of project based DM accounted for by smoothing program

Cost Escalation

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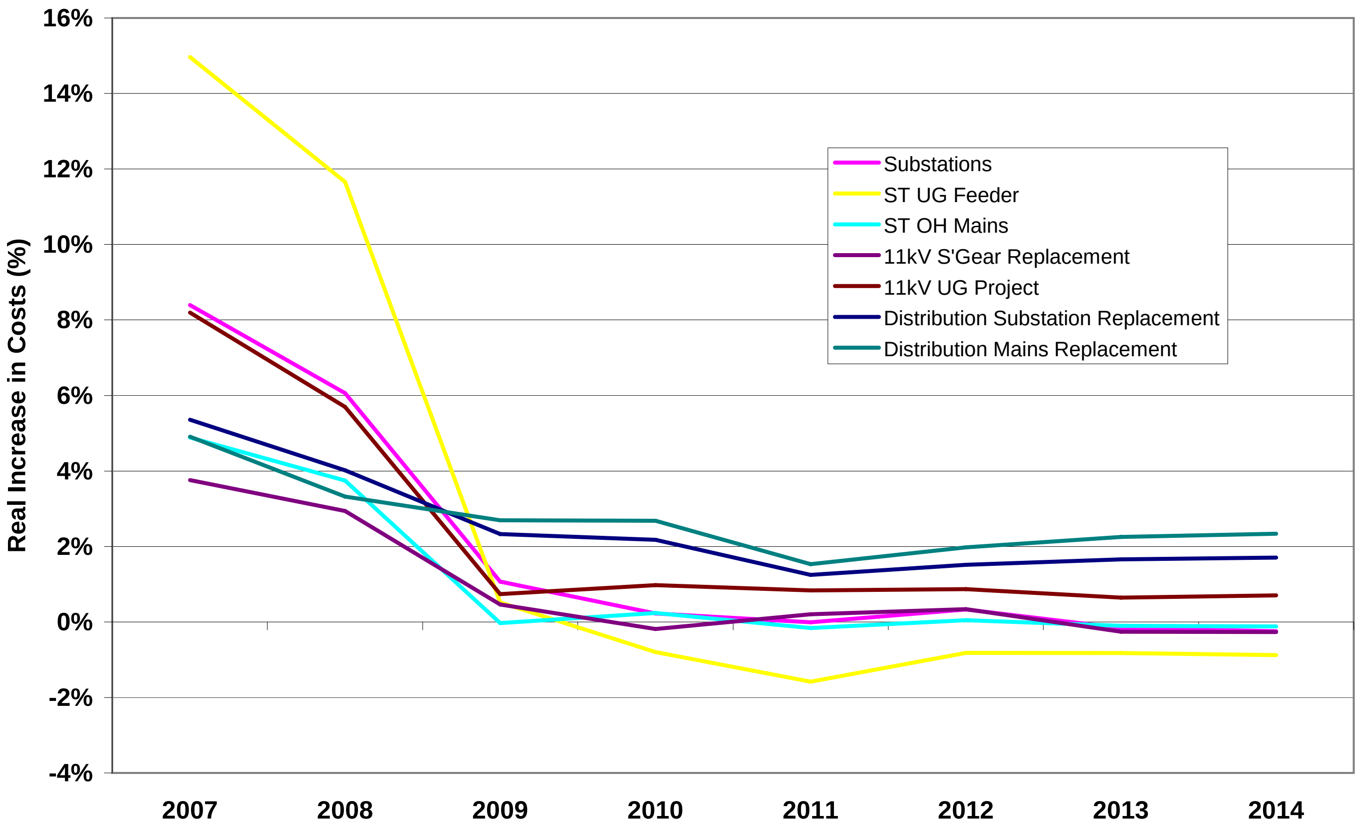
Forecast project cost indices



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Impact of real cost changes & inflation

	FY10	FY11	FY12	FY13	FY14
Real rates (%)					
Copper	-6.30	-4.20	-2.80	-3.10	-3.10
Aluminium	-0.50	-0.20	0.30	0.00	0.00
Crude Oil	-3.80	-1.30	-0.50	-2.00	-0.90
Steel	0.30	0.20	0.20	0.20	0.20
EGW NSW Wages	3.90	1.90	2.80	3.50	3.70
Wages General	2.40	1.90	1.80	2.00	2.00
Construction costs	0.90	0.70	1.10	1.90	2.60
Producer's margin	6.10	7.60	0.00	0.00	0.00
Land & easements	4.10	4.10	4.10	4.10	4.10

- **'Electrical' labour index by EGW NSW Wages**
- **Non 'Electrical' labour index by General Wages**
- **No established price indexes for electrical equipment**
- **Material indexation is based on a composite index**

(Table 10.2)

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Operating Costs

Operating Costs

- **Opex is split into 3 parts:**
  1. Maintenance
  2. Network support
  3. Business support

- **Program has been designed to link capex & opex outcomes**
  – Opex increases with numbers of assets, but
  – Opex may decrease if older assets are replaced with newer, less expensive assets (trade-off)

- **Two methodologies used for direct system forecast**
  – Top-Down method – derives expenditure forecast
  – Bottom-Up – used as a check

1. Maintenance Opex

Definition: **Direct system related maintenance costs only**

Maintenance based on annual forecast asset base:

Capital base = Existing assets + new assets -decommissioned assets for each year

Maintenance forecast methodology:

- **Links with capital outcomes**
- **Shows positive impact of replacement works on recurrent expenditure**
- **Shows cost of deferring replacement**
- **Shows future maintenance costs**
- **Demonstrates the long term benefits of reaching sustainable levels of replacement**

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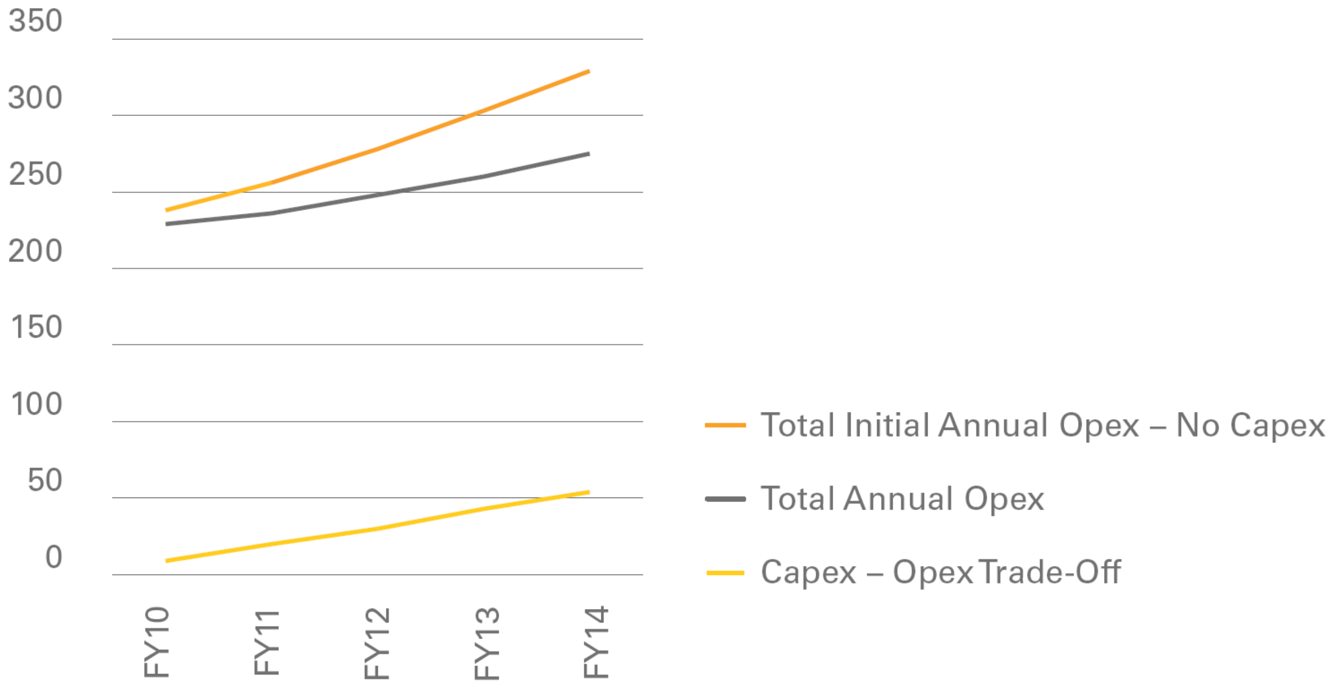
1. Maintenance Opex

Forecast incorporates positive impact of replacement (worth more than $50m per annum by 2014)



(Figure 6.4)

2. Network Support Opex

Definition: **Includes system related operating costs except maintenance (i.e. control room, demand mgt etc)**

- **Forecast uses 2006/07 costs as base line**
- **Includes analysis of changes to costs over time**
  - and identifies drivers of change
- **Links drivers to inputs**
  - customer numbers, etc
- **Real cost indexation applied**

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3. Business Support Opex

Definition: **All network opex that is not directly related to electrical system**

- **Forecast uses 2006/07 costs as base line**
- **Includes analysis of changes to costs over time**
  - and identifies drivers of change
- **Links drivers to inputs**
  - customer numbers & call centre volume, etc
- **Real cost indexation applied**

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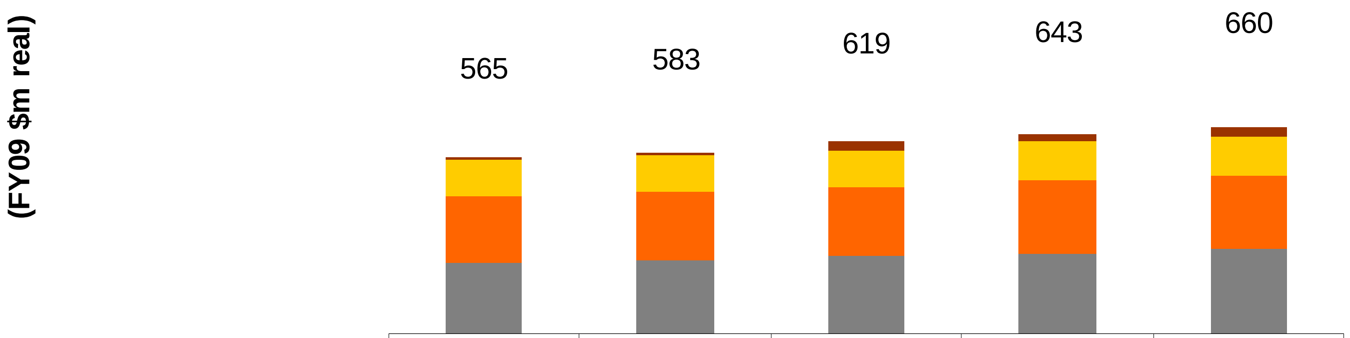
Total Opex



	FY10	FY11	FY12	FY13	FY14
	565	583	619	643	660
Debt & Equity Raising	7	9	26	27	29
Business Support	116	117	119	123	120
Network Support	213	221	226	233	237
Maintenance	229	236	248	260	275

Maintenance Network Support Business Support Debt & Equity Raising

- **Total Opex over the 2009-14 period is $3.07 billion**

Outcomes

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Growth Outcomes

Outcomes:

- All zone substations meet licence compliance requirements
- No STSs loaded above firm rating
- 31 zone substations loaded above firm rating but compliant

Zone and Subtransmission substations	2005	2010
Over firm rating but within criteria	43	31
Over firm rating	25	6
Total	**68**	**37**

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Upper Hunter Region – 2010

Substation Loading

- > 100% Firm
- > Licence Conditions

Upper Hunter Region – 2015

UPPER HUNTER

EnergyAustralia

Lower Hunter Region – 2010

Lower Hunter Region – 2015

Substation Loading

- > 100% Firm
- > Licence Conditions

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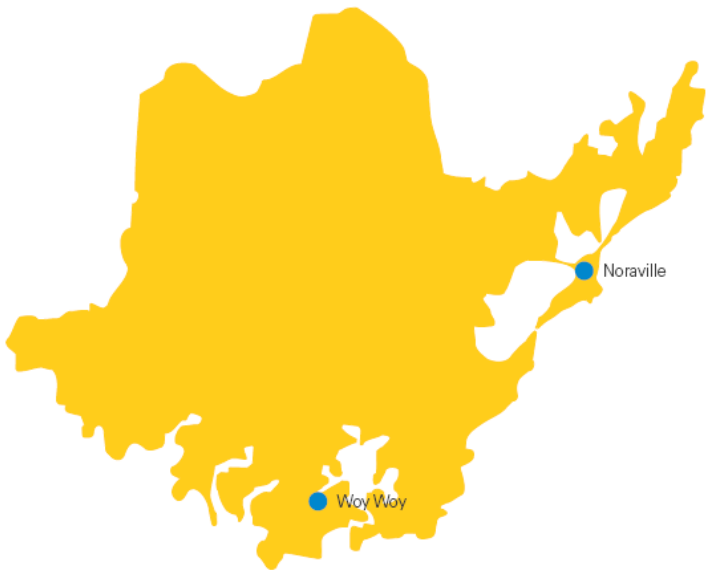
Central Coast Region – 2010

Central Coast Region – 2015



Substation Loading

- > 100% Firm
- > Licence Conditions

Sydney North Region – 2010

Substation Loading

- > 100% Firm
- > Licence Conditions

Sydney North Region – 2015

Substation Loading

- > 100% Firm
- > Licence Conditions

Sydney City – 2010

Sydney City – 2015

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Substation Loading

- > 100% Firm
- > Licence Conditions

Sydney South Region – 2010

Sydney South Region – 2015

Replacement Outcomes (base case)

Assumptions: Replacement occurs consistent with OIM recommendations based on condition and risk

Outcomes:

- **Replacement of 132kV oil cables – 141km**
- **Replacement of 33kV gas cables – 155km**
- **Significant replacement of aged 11kV switchgear – 1263 panels**

- **Age profile increasing in some asset categories – Distribution Subs, Distribution Mains**
- **Age profile decreasing in assets – Transmission Mains, Zone Subs, and Transmission Subs**

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Compliance Outcomes

EnergyAustralia is compliant:

- **Design, planning criteria** **(input criteria)**
  - N-2 in CBD by 2014
  - 11kV utilisation is 80% by 2014
- **Reliability outcomes**
  - Average feeder category targets met (output criteria)
  - Individual feeder targets met (output criteria)

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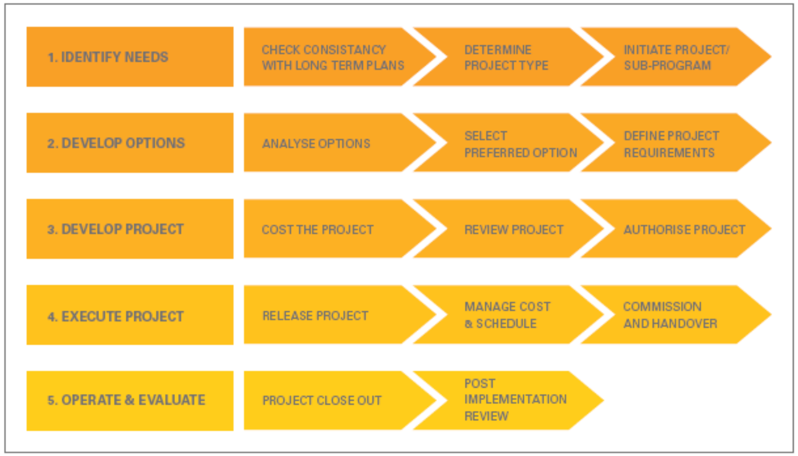
Delivery strategy

Workforce	**EnergyAustralia Internal**	**EnergyAustralia Contractors**	**Clause 7 Contractors**	**MoU Alliance**	**MoU Distribution**	**ASP Contestable**
Scope of Work	Traditional Spread of Works	Tree trimming, Undergrounding, Civil Works, Design Engineering, Bulk Lamp Replacement	One-off contracts, eg Pinc, Underground Transmission	Design, Build & Connect Major Substations. Other works as required.	Pole Replacement, Bulk Lamp Replacement, ABC & CCT	Customer Connections, Recoverable Works: Minor Works & Asset Relocation
Implementation Milestones	Identified Need Withdraw from Contestable Market	Reviewing Need To Be Confirmed	Reviewing Need To Be Confirmed	Signed MoU Shortlisted Partners	Signed MoU Establishing Contracts	Changed Point of Connection Changed Recoverables Policy
Share of Future Program	**50%**		**50%**			
Est Growth 2010 to 2014	+	+++	++	++++	++	++

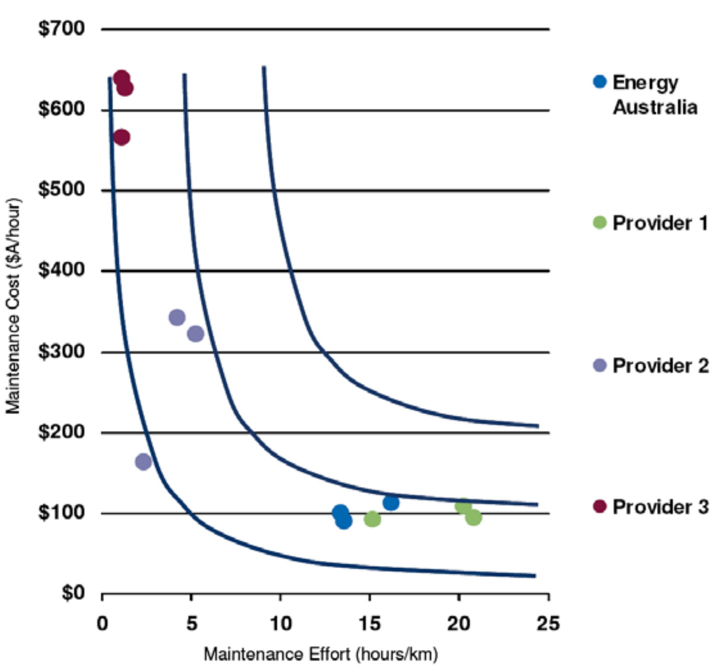
Efficiency



Governance arrangements

Benchmarking studies

Maintenance cost against maintenance effort – Overhead Line



Pass-through – specific events

1. **Dead zone event – event between 2 June 2008 and 1 July 2009**
    - AMI
2. **Force majeure event – "act of God"**
    - June 2007 – 1 in 100 year storm
    - Newcastle earthquake
3. **Cost and demand input variance**
    - Acknowledges *forecast* nature of real cost escalation estimate
    - protects incentive mechanisms within framework
4. **Joint planning event**
5. **Compliance event**
    - Covers more than *regulatory obligations*
6. **Customer connection event**
    - Large, new non-forecast customer connection
7. **Separation event**
    - Caters for unknown costs of sale model for EA's retail business

EnergyAustralia

Questions

Public lighting

EA’s Public lighting service has revenues of approx $30 million p.a. (2% of total revenues)

EA’s public lighting proposal:

- Uses an annuity approach rather than roll-forward approach
- Includes rebate mechanism to smooth transition to cost-reflective pricing

Rebate mechanism:

- Designed to limit price shocks in any year to 11% (+CPI)
- Cost of rebate to EA is $8.8 million from 2009-14

Proposal designed to meet most provisions of Public Lighting Code