APPENDIX 8

The NOUS Group, *Transend Networks 30+ year network vision project, final report,*

May 2007

This document is confidential to Transend Networks

Transend Networks

30+ year network vision project
Final report

May 2007

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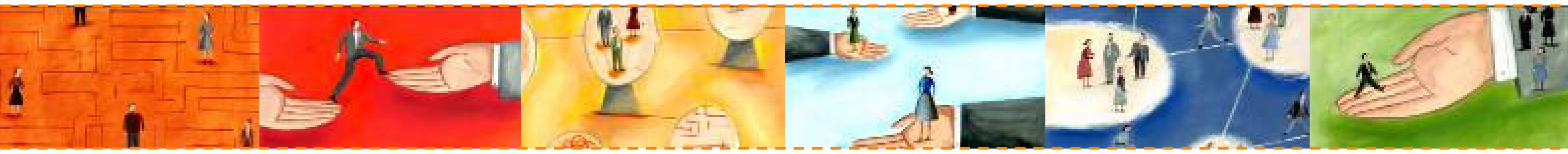
THE NOUS GROUP



THINKING DOING LEADING

The Nous Group is a management consultancy which specialises in strategy, public policy, organisational capability and leadership development.

Nous consults extensively in the energy sector, and has developed long term strategic 'visions' for several leading organisations in the Australian energy industry.

Table of Contents

A. Executive summary

1. The project

Transend Networks engaged The Nous Group in late 2006 to assist in development of a 30+ year vision for the Tasmanian electricity transmission network suitable to support Transend's 2007 revenue application to the Australian Energy Regulator.

The project encompassed discussions and workshops with senior stakeholders within Transend and in a wide range of external stakeholder organisations in the Tasmanian government sector and electricity markets at state and national levels. A scenario planning approach combined with network modelling was used to explore the range of possible challenges in long term network development. Internal workshops reviewed the business response capabilities that Transend will need to effectively address these challenges and other stakeholder requirements.

The outcomes of the project include recommendations for strengthening some key business response capabilities and identification of the key strategic issues that must be addressed for efficient and flexible long term development of the network.

2. Stakeholder requirements

Stakeholder discussions and joint scenario workshops identified the key stakeholder demands that Transend should address as:

1. **Reliability:** Market access for generators, and continuity of supply for all customers
2. **Pricing:** Prudent investment that does not exceed the needs of the market
3. **Responsive facilitation of projects:** Fast responsive action to meet new needs
4. **Leadership:** An authoritative industry voice independent of sectional interests.

These requirements have been used in identification of the key strategic issues that must be addressed in network development and Transend's business response capabilities.

3. Factors that will shape transmission investment

Like other transmission networks, Tasmania's transmission network is shaped by demographic, load and generation factors and these were researched and reviewed in the project:

1. **Context:** Tasmania has two major load centres, modest demand growth projections and a relatively flat demand duration curve due to the presence of major industrial customers. Power generation is dominated by hydro electricity with smaller contributions from gas and wind power. The Tasmanian transmission network is characterised by a North-South backbone with spurs determined largely by the location of generators. The operation of Tasmania's transmission network has changed fundamentally with its connection to the mainland in April 2006 via Basslink.

2. **Demand:** Current projections for long term demand growth are relatively modest. However, long term factors could potentially produce quite different outcomes. Climate change could increase Tasmania's population; penetration of domestic and commercial air conditioning could increase the peakiness of the load duration curve, as could any departure of major industrial load; and new mining activity on the West Coast may have an effect.

3. **Supply:** In the long term, even without new dams, there is potential for about 260MW of additional hydro generation, as well as significant potential for pumped storage. As scale economies bring down manufacturing costs, wind power will be less reliant on policy support and may become an attractive investment in its own right. Exploitation of Tasmania's excellent wind resource could reach 600-1,000MW including wind farms on the Central Plateau and the North East coast. The Bass Strait gas pipeline has capacity for gas powered generation well beyond Alinta's announced Tamar Power Station and this could be placed close to Hobart, Burnie or George Town.

4. **Environmental:** Climate change and government action to manage greenhouse gas emissions is a major uncertainty for the industry. That the change will be profound and wide ranging is certain. Demand curves are likely to become peakier across Australia and a carbon price would advantage Tasmania's hydro and wind resources.

5. **NEM connection:** The benefits of Basslink are already apparent - 'drought proofing' of Tasmania's power supply, market access for Tasmanian generators, improved flexibility of operation of hydro schemes to increase the value of harvested water, and simple market arbitrage. However, Basslink is a single link and hedging of inter-region trading against 'physical risk' of loss of the link is a challenge. The lack of link redundancy may also place constraints on Transend's work program, as access to transmission assets associated with the link may become more difficult to arrange in the future. In the long term, a second link may be warranted for redundancy and to allow Tasmania to exploit premium mainland prices for 'clean green' peaking power.

4. Potential transmission network capacity requirements

From research and review of 12 primary factors that will influence transmission development in the long term, four scenarios were developed and discussed in workshops of senior managers and external stakeholders. The scenario approach was used to 'break out' of traditional thinking and explore the boundaries of reasonable credibility to identify long term outcomes that Transend may have to address. The four scenarios were:

Growth: Climate change and other factors produce much higher demand growth than current forecast.

Import: A range of factors (including low mainland energy prices) lead to Tasmania relying on electricity imports from the mainland via increased Bass Strait transfer capacity.

Export: A range of factors (including high mainland energy prices due to carbon imposts, and excess local generation) lead to much of the Tasmanian electricity industry being directed towards export of 'green' peaking power to the mainland NEM regions via increased Bass Strait transfer capacity

Business as usual: Tasmania's current situation continues with only slow incremental growth in demand and no significant discontinuities in the operating circumstances of the network business.

The first three scenarios guided network modelling that identified network constraints which could emerge over the next few decades with sufficient impact on overall transmission performance as to justify remedial investment. The results of the modelling show that such network constraints may emerge in most areas of the network, requiring voltage upgrades, additional lines, or both.

5. Potential transmission network development

Analysis of the network modelling results reveal that potential demands over the next 30+ years will require effective development and implementation of four key areas of network development strategy indicated in Figure 1:

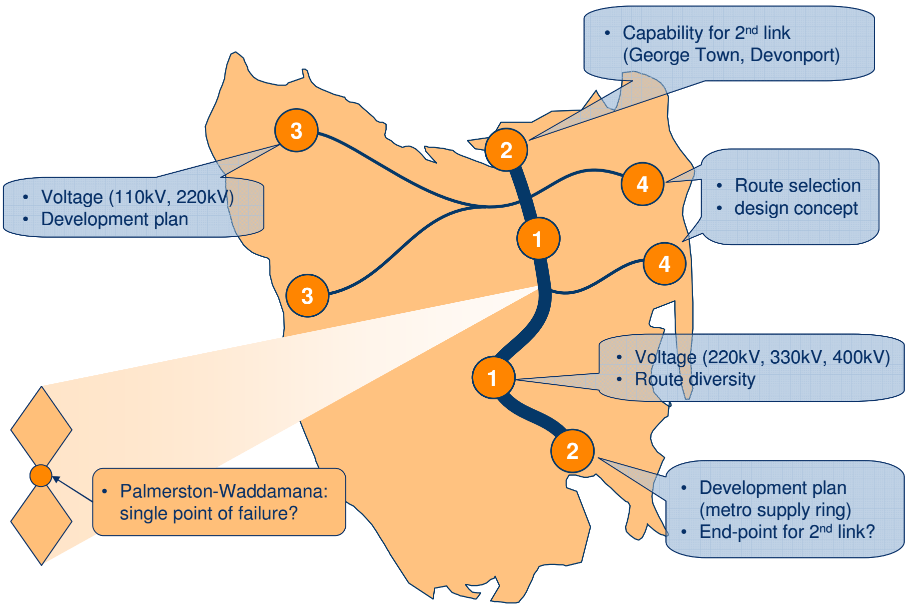


Figure 1: Strategic issues in long term transmission network development

The four areas of network development strategy are:

1. Strategy for the transmission network backbone

Good potential for route diversity is available North of Palmerston and South of Waddamana and this should be preserved and further developed. These two substations and the easement between them will remain potential single points of failure in the long term and they should be designed for high reliability against major events.

Voltage level selection for the long term development of the backbone network is a key strategy decision. Potentially viable options range from the current 220kV up to 400kV. Analysis will identify the voltage that will provide optimum results for stakeholders in terms of price, reliability and flexibility of future investment timing. The optimum strategy is likely to be:

- Build all new backbone lines (including those on redundant routes North of Palmerston and South of Waddamana) for later operation at the selected voltage.
- Upgrade lines and substations to the selected voltage only when justified by actual demand growth.

2. Strategy for the major northern and southern load centres

A strategic development plan is required for the Hobart region to ensure reliable supply to directly connected customers and commercial centres. A planning study should be developed in conjunction with local planning authorities. This plan should be informed by transmission technology developments that can incorporate transmission infrastructure into the built environment.

Transmission planning for the North and South load centres should encompass[1] a potential future requirement to connect a second major Bass Strait link.

3. Strategy for the North West and West Coast

Strategic development plans for these regions are required. A study is needed to identify the optimum voltage level for future development of the North West and West Coast network.

4. Strategy for the East Coast

A strategic design concept and development plan is required that identifies the optimum line configuration for this region, i.e. is it better to upgrade current spurs from single circuit to double circuit or is a line parallel to the coast between the key centres of Derby, St Marys and Triabunna a better option? Local planning authorities should be involved in production of the high level plan.

6. Recommendations

This network vision project has explored the range of possible long term futures that Transend may have to address and it has identified a number of key strategic issues that require attention for long term success. It should lead on to more detailed work in each of the areas of strategic significance that have been identified.

It is recommended that Transend proceed with the following:

[1] Although the present Basslink connection is a privately funded interconnector, it is prudent for Transend to include consideration of a second link in its planning, as (a) it is possible that Basslink could be converted to a Transmission Network Service Provider (TNSP) at some point in the future, and (b) any potential second connection could also be developed as a TNSP.

1. Develop a stakeholder consultation document

This network vision project report is a valuable basis for consultation in the lead up to Transend's revenue application. Transend should develop a suitable public version to support stakeholder consultations.

2. Produce long term network plans

To effectively address the strategic issues in long term network planning, Transend should initiate planning studies to:

i. Select the optimum voltage for future backbone network development

ii. Produce development plans for Hobart and the North West and West Coast regions

iii. Produce a design concept[2] and then a development plan for the East Coast region

iv. Identify options to ensure capability to connect a second mainland link

v. Develop a detailed yearly list of initiatives for progress from status quo to vision.

These studies should be done in conjunction with stakeholders wherever possible to build Transend's credentials as a key industry planner. The forward plans and list of projects should be detailed for the first ten years, less so for the 10-15 year ahead period, and indicative for the remaining decades.

Transend should proactively participate in and influence implementation planning of the recent COAG decision to set up a national transmission planner. This will help ensure that jurisdictional planning in Tasmania is consistent with national planning, and that Transend's internal planning activity can mesh with new national arrangements as they emerge.

[2] Design concept is defined here as selecting an optimum network topology. A development plan (a sequence of projects by which capacity can be progressively increased) will then follow from the confirmed design concept.

B. The project

In October 2006, Transend commissioned Dr Tony Marxsen and Simon Lancaster of The Nous Group to assist in development of a 30+ year vision for its electricity transmission network. The purpose of the high level vision is to ensure Transend is well placed to respond to future network development challenges to 2040 and beyond. The vision will also guide more detailed investigations which in turn will deliver a ten year development plan suitable to support Transend's next revenue application to the national energy regulator.

The vision is primarily for internal use, though it will also have value in communicating the organisation's strategy to shareholders, regulators and other stakeholders. It will serve as a source of knowledge to influence the diverse community of stakeholders and planning organisations that shape Transend's business environment.

The 30+ year vision project objectives were to:

1. Define the long term context for Transend in the lead-up to its next revenue application, using a consultative approach to engage key industry stakeholders
2. Identify strategic business actions for Transend to respond to both medium term (15 year) trends that are already emergent and a range of long term (30 or more years) possible scenarios that cannot yet be clearly foreseen
3. Inform and broaden the thinking of Transend's management and engineering teams to increase strategic awareness and flexible thinking to address the wide range of possible future challenges that may face the organisation.

In essence, this vision will provide guidance to Transend on how to ensure its transmission business is sustainable well into the future.

The vision project encompassed a number of phases as summarised in Figure 2:

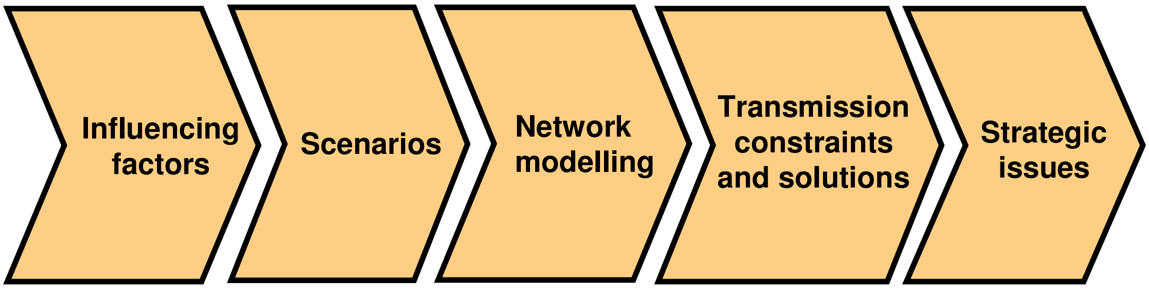


Figure 2: Project methodology

A detailed description of the project approach and methodology is set out in Appendix 4.

C. Stakeholder requirements

To be an effective player in the Tasmanian and national energy markets, Transend must respond to the demands of its stakeholders, including its owners. This vision needs to reflect those requirements and clearly set out how Transend will respond to them.

For Transend, the key stakeholders include those shown in Table 1:

Customers	Tasmanian government (owner)
• Generators (Hydro Tasmania, Roaring 40s, Bell Bay Power, Alinta and new entrants) • Major industrial customers • Distribution networks (Aurora Energy and other networks) • Customer associations (eg, Tasmanian Chamber of Commerce and Industry)	• Shareholder Ministers • Department of Infrastructure, Energy and Resources • Department of Treasury and Finance • Department of Economic Development
Australian government and national government bodies	**Other stakeholders**
• COAG • Ministerial Council on Energy • Department of Industry, Tourism and Recreation • Productivity Commission • Australian Greenhouse Office	• Other transmission companies • Suppliers • Local councils and planning authorities • Community groups • Environment and heritage groups • Unions • Investors and markets • Media
Regulators	**Market managers and operators**
• AER • OTTER • ACCC	• NEMMCO • AEMC and Reliability Panel

Table 1: Transend's key stakeholders

During the course of development of this vision, stakeholders were consulted extensively, through 26 interviews, and an interactive workshop. This consultation process identified a number of specific requirements and expectations, which ultimately reduce to just a few key expectations:

1. **Reliability of supply**
   Stakeholders clearly expect that Transend will ensure that customers receive reliable supply that they can build their businesses around. For generators, this means a transmission network that can handle peaks, that can facilitate access to Tasmanian and mainland wholesale electricity markets, and that will not result in generators being denied dispatch due to transmission capacity constraints. Major industrial customers demand a high level of reliability, with few and short outages, and no network constraints for their business. Governments and regulators are also seeking high levels of reliability through service standards to ensure positive stakeholder perceptions of the electricity supply system.

2. **Attractive pricing**
   Low pricing reflecting prudent investment is a key expectation of customers and

stakeholders more generally, e.g. government interest in support for economic development from an efficient transmission system. Transend is expected to manage its investment program to (a) ensure that there is no overcapitalisation (e.g. by building infrastructure too far ahead of demand), (b) avoid price shocks; and, (c) ensure investment is adequate to meet reliability requirements. To address this need, Transend's planning capability must effectively anticipate demand growth, effectively communicate with stakeholders, and effectively manage expectations.

3. **Responsive facilitation of major development projects**
   Transend's stakeholders expect it to work in partnership with them to facilitate their new developments, and ensure that transmission supply is available when required, appropriate and efficiently constructed.

4. **Leadership in representing industry interests**
   Many stakeholders see Transend, due to its nature as a fully regulated network business that interacts with all market participants, as uniquely positioned to act in the overall industry's best interests with authority derived from its expertise and knowledge of the whole Tasmanian electricity industry and its relative lack of partisan bias.

These stakeholder requirements and expectations have underpinned the project's analysis of the current context in the Tasmanian energy market, the likely influencing factors over the next 30-40 years, the potential network capacity requirements and ultimately, how the network might develop to meet these needs. Transend will need to continue to listen closely to its stakeholders to ensure that its business plans continue to take into account their needs - and adjust its network vision accordingly.

D. Context

There are a number of demographic, load and generation realities that define the Tasmanian electricity transmission network. Some salient points of these realities are set out below[3].

Tasmania has two major load centres, modest growth projections and currently enjoys a relatively flat load duration curve

Aspects to note include:

1. Demographics and Tasmania's economy:

The Tasmanian population was 482,000 in 2004. Tasmanian Gross State Product[4] is projected to average 1.7% annual growth over the 35 years to 2040, or 80% in total. Population growth over the same period is projected by NIEIR to average 0.3% per annum, or rise by nearly 50,000 persons in total[5], i.e. 10% (see Table 2).

Period	Forecast average annual growth (NIEIR)		
	Gross State Product	Population	Dwelling stock
2005-2010	2.6%	0.4%	0.8%
2010-2015	1.7%	0.2%	0.8%
2015-2020	1.6%	0.1%	0.6%
2020-2025	1.5%	0.2%	0.6%
2025-2030	1.9%	0.4%	1.0%
2030-2035	1.6%	0.3%	0.8%
2035-2040	1.5%	0.2%	0.6%
2005-2040	**1.7%**	**0.3%**	**0.7%**

Table 2: Tasmanian GSP, population and dwelling stock growth to 2040

2. Tasmania's electricity market:

Maximum demand in 2005/06 was 1,808 MW for Tasmania only, or 2,111 MW including Basslink export. Energy transmitted in 2005/06 was 10,945 GWh. The current load profile is dominated by five directly connected, major industrial customers with flat load duration curves. Together these make up approximately 60% of the total load. Load is concentrated in the North and South East of the island (see Figure 3).

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[3] Material in this section has been drawn from the following sources, where further detail may be obtained:

- Australian Bureau of Statistics (www.abs.gov.au) and NEMMCO (www.nemmco.com.au)
- NIEIR, 'Energy scenarios for Tasmania to 2040', October 2006 (report commissioned by Transend and included as Appendix 1 to this report).
- Transend 2005/06 Annual Report and 2006 Annual Planning Report

[4] It is relevant that the energy intensity of Australia's economy (energy used per $ of GDP) is reducing by 1-2% per year.

[5] This estimate is higher than that of some other sources, which predict a decline in Tasmania's population beyond 2015.

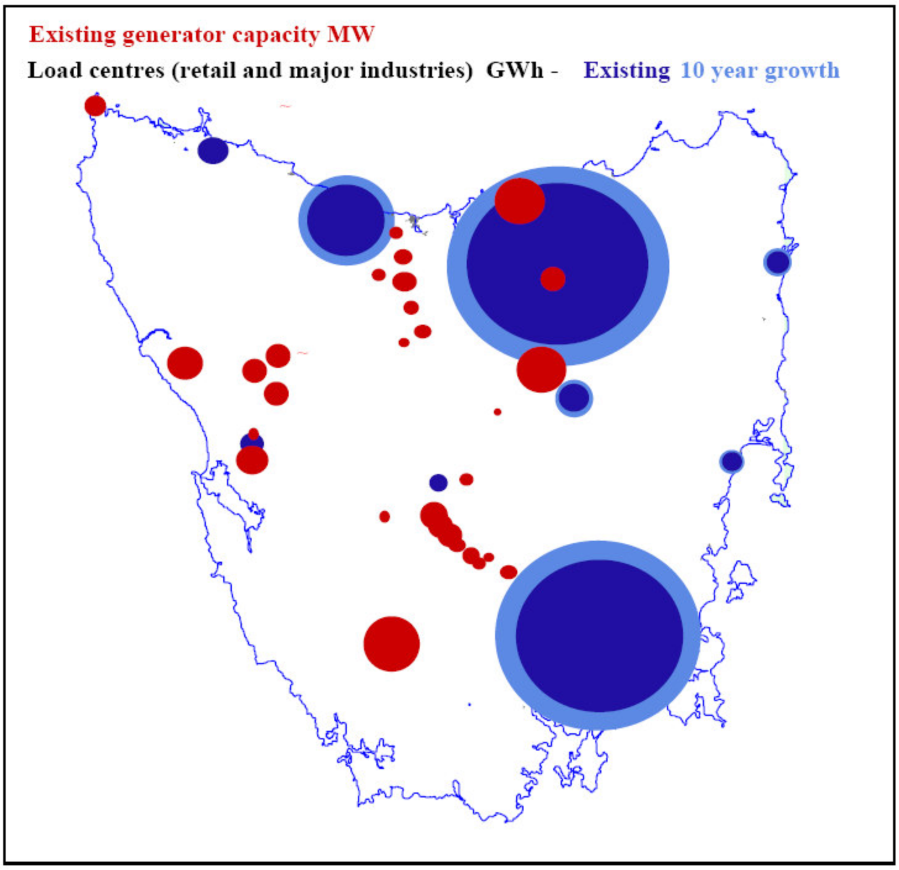

Figure 3: Tasmanian load and generation locations

The Transend network is characterised by a North-South backbone, with spurs determined largely by location of generators

Large parts of the North West, North East and South West are not strongly linked to the backbone transmission network (see Figure 4).

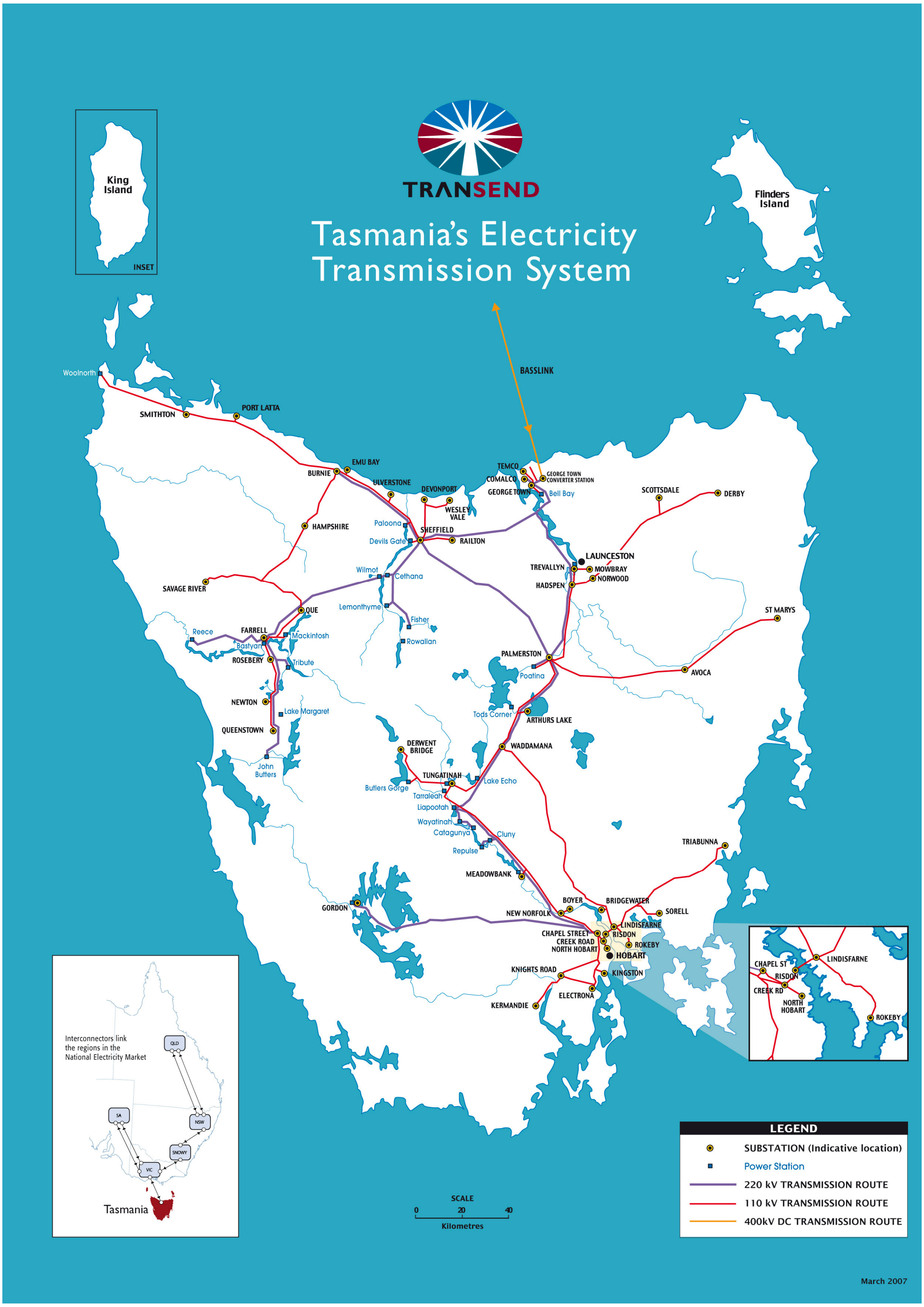

Figure 4: Transend's transmission network

The operation of Tasmania's transmission network has changed fundamentally with the Basslink cable coming into service

Basslink connects the Tasmanian network to the mainland and the NEM. It was commissioned for full commercial service on 28 April 2006. The cable has capacity for 480MW import to Tasmania and 600MW[6] export from Tasmania.

Since Basslink came into service, imports from the mainland have exceeded exports by nearly a four to one ratio, particularly over September-November 2006 (see Figure 5). This is largely due to the current drought and consequent depletion of Hydro Tasmania's water storages.

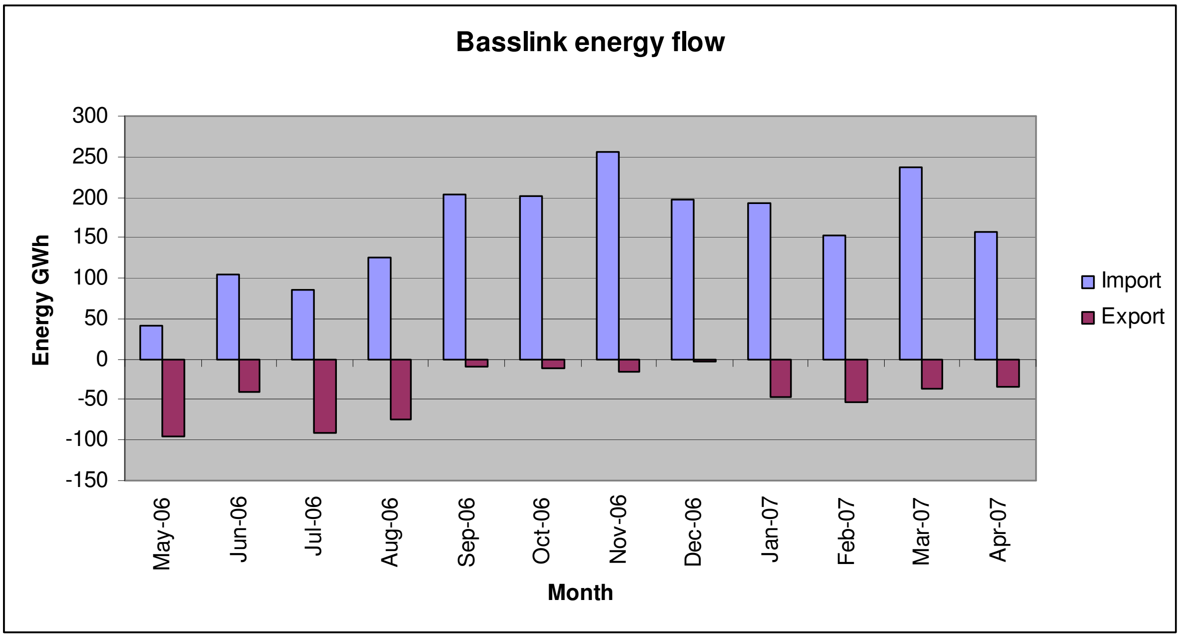

Figure 5: Energy flows through Basslink May 2006 to April 2007

Spot wholesale electricity prices were established when Tasmania joined the NEM, with strong price congruence since Basslink came into service in April 2006 (Figure 6) except in months such as January 2007 where Victorian demand peaks led to high local prices and Basslink export capacity was fully utilised – in these conditions, it is normal for prices in the two regions to diverge.

[6] This is a short term (six hour) rating which depends on flow on the cable in the previous 24 hours.

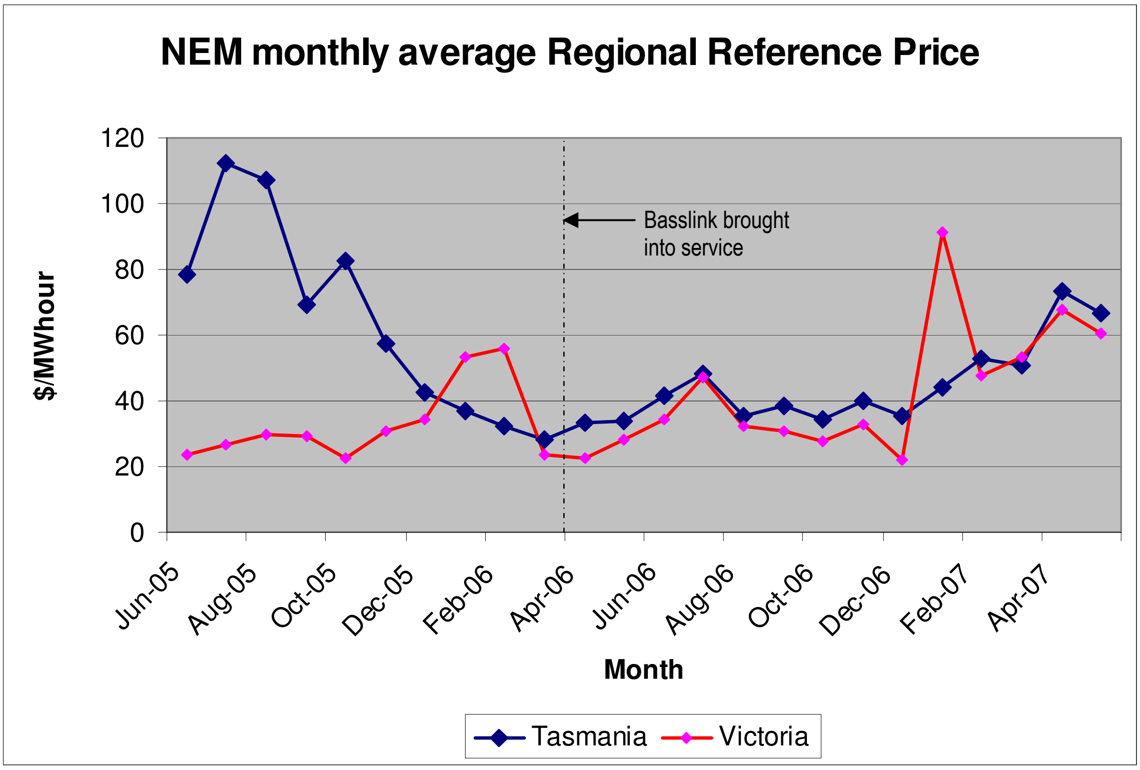

Figure 6: Average monthly wholesale electricity prices: Victoria and Tasmania

Note that price data for the period prior to Basslink connection (April 2006) is not particularly significant as:

- All but a few percent of the Tasmanian electricity supply is hedged against spot price variations, so the price variations shown in Figure 6 were not reflected in delivered energy cost to customers. Spot prices will have more significance as supply diversity increases with new generator entrants such as the planned Alinta gas power station in the Tamar Valley.
- The period prior to Basslink connection spanned a very dry winter and was also regarded somewhat as a 'NEM familiarisation' period by Tasmanian market participants.

E. Factors that will shape transmission development

The stakeholder interviews, workshops and The Nous Group's own research have identified a series of factors which are likely to have an impact on the development of the transmission network over the next 30+ years, and consequently on Transend. These influencing factors have been divided into 6 categories:

1. Demand
2. Supply
3. Environment
4. Ownership
5. Regulation
6. NEM connection

Each of these factors is briefly described in the following sections.

1. Demand

Overall, NIEIR projections suggest relatively modest growth for Tasmania over the next few decades, in terms of population, economic and demand growth (refer Table 2 on page 12).

Even these modest rates of growth would translate into an increase of winter peak energy demand of more than 50% (ie 1,267MW increase on 2005/06 maximum demand of 1,808MW) over the next 35 years as shown in Table 3:

Period	Growth in maximum demand over the period (MW)					
	Winter			Summer		
	10% PoE[7]	50% PoE	90% PoE	10% PoE	50% PoE	90% PoE
2010-2020	313	310	278	221	217	213
2020-2030	348	332	331	228	225	222
2030-2040	385	380	366	246	242	239
2005-2040	**1267**	**1221**	**1117**	**907**	**876**	**850**

Table 3: NIEIR Tasmanian demand projections 2005-2040 ('Business as usual' scenario)[8]

However, it is possible to envisage much higher rates of population growth over the next 30+ years under certain demographic scenarios. For instance, climate change could increase Tasmania's desirability as a destination for both tourism and retirement (the increasing 'sea-change' and 'tree change' phenomena). Such developments could lead to much higher growth in population, economic development and energy demand. In addition, the location of demand could shift, with higher demand growth on the East Coast and in the North East in response to population movements.

Increasing temperatures under climate change could also be expected to cause increased air conditioner penetration in Tasmania, with a possible move towards a summer demand peak. When compared to other states with warmer climates, Tasmania has had a historically low

[7] PoE: Probability of exceedence. 10%PoE is the level that will be reached or exceeded once in ten years, whereas 90%PoE is the demand that will be exceeded in nine out of every ten years.

[8] NIEIR, Energy scenarios for Tasmania to 2040, Oct 2006 (report commissioned by Transend and included as Appendix 1 to this report)

rate of adoption of domestic air conditioning. However, the current displacement of wood heating by heat pumps (i.e. reverse cycle air conditioners) provides a base for much greater penetration in the future.

Climate change could also see reduced demand growth due to price elasticity if a carbon price were introduced. Table 4 shows that NIEIR projects an increase of only 647MW if a 'stringent' carbon management scenario were introduced, compared to the 1,267MW projected under the 'business as usual' scenario shown in Table 3.

Period	Growth in maximum demand over the period (MW)					
	Winter			Summer		
	10% PoE[9]	50% PoE	90% PoE	10% PoE	50% PoE	90% PoE
2010-2020	129	125	111	107	102	98
2020-2030	151	147	142	114	112	110
2030-2040	147	145	140	109	107	106
2005-2040	**647**	**617**	**533**	**542**	**514**	**490**

Table 4: NIEIR Tasmanian demand projections 2005-2040 ('Stringent carbon price' scenario)[10]

The other important factor influencing demand levels, given Tasmania's load profile, is the presence or absence of major industrial customers. Supply contracts for all five major industrial customers are due for renewal by 2014 and departure of one or more of these loads would have a major impact on both overall demand and the 'peakiness' of the load curve. The plants being supplied are small when considered on an international scale, so their long term viability may be open to question. Balanced against this, these customers' existing sites have an incumbency value and may be prime assets, given the worldwide difficulty of establishing new green-field sites in these industries.

There is also the possibility of increasing mining activity in the West and North-West, particularly if demand for minerals continues to be strong over the long term. This may have the potential to offset loss of other industrial customers should this occur.

The gas pipeline from the mainland is a potential influencing factor, as gas may slowly displace some electricity load in the industrial, commercial and domestic sectors. However, stakeholders report it is likely that gas will impact use of coal, fuel oil and wood fuels, rather than electricity where its impact is estimated to be low.

2. Supply

In the past, Tasmania relied almost exclusively on hydro power for its electricity supply. However, other sources of generation – in particular gas and wind – have diversified the supply mix in recent years (see Table 5).

[9] PoE: Probability of exceedence. 10%PoE is the level that will be reached or exceeded once in ten years, whereas 90%PoE is the demand that will be exceeded in nine out of every ten years.

[10] NIEIR, Energy scenarios for Tasmania to 2040, Oct '06 (report commissioned by Transend and included as Appendix 1 to this report). The stringent scenario has a carbon price of $10/ton in 2010 increasing to $50/ton in 2040. It is also assumed that there is no loss of major industrial load.

Type	Power stations	Nameplate capacity	Portion
Hydro	27 stations, 50 turbines	2277 MW	83%
Gas	1 thermal, 3 Open Circuit Gas Turbines	335 MW	12%
Wind	2 farms, 62 turbines	140 MW	5%
	Total:	**2752 MW**	**100%**

Table 5: Tasmanian generation capacity at April 2007

Since Basslink went into service in April 2006, imports have also become a vital part of the mix. In the 12 months to April 2007, imports supplied around 13 per cent of Tasmania's consumption of electricity (Figure 7).

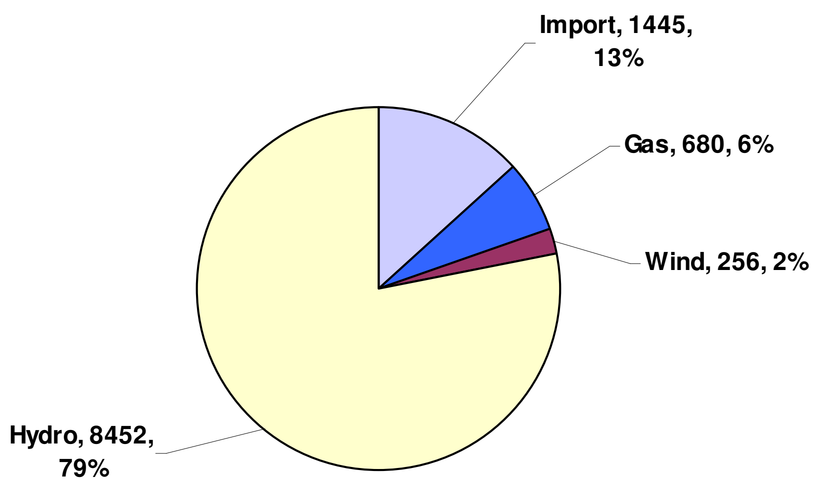

Figure 7: Tasmania electricity supply (GWh) - May 2006 to April 2007

The factors arising on the supply side of the Tasmanian electricity industry vary by 'on-island' generation sector, as follows[11]:

a. Hydro

Hydro power continues to be the dominant source of Tasmanian electricity, comprising 85% of total Tasmanian generation capacity by nameplate rating. However, opportunities to further expand hydro capacity are likely to be limited:

- All stakeholders agree it is unlikely any major new dams will be built in Tasmania in the foreseeable future
- The Gordon Power Station has unused accommodation for two further 144MW generators which could be installed to increase capacity

[11] Considerations of the NEM connection across Bass Strait (which can be considered as another generation source) are addressed in Section E6 below.

- Many other stations could potentially benefit from refurbishment of turbine runners and guide vanes with modern equipment offering higher hydraulic efficiency. However, the capacity increase is likely to be no more than 5%, i.e. perhaps 120MW in total.

Some potential options may exist to increase the market value of existing capacity:

- Possible additional regulating pondage on some 'run of the river' cascades to improve dispatchability of cascade capacity
- Transformation of one or two stations to pumped storage by installation of pumps and new pondage below the power station.

Sensitivity of hydro power to future climate change is a major uncertainty. In 10 successive years of below average inflows, hydro storages in Tasmania have dropped from a high in 1996 of over 80 per cent to around 18 per cent in May 2007, the lowest they have been since 1968 when they fell to 14.2 per cent. Last year (2006) saw the lowest inflows into Tasmania's hydro storages since the 1967 record low. It is not yet clear if the drought is a one-off event or an early indication of imminent climate change.

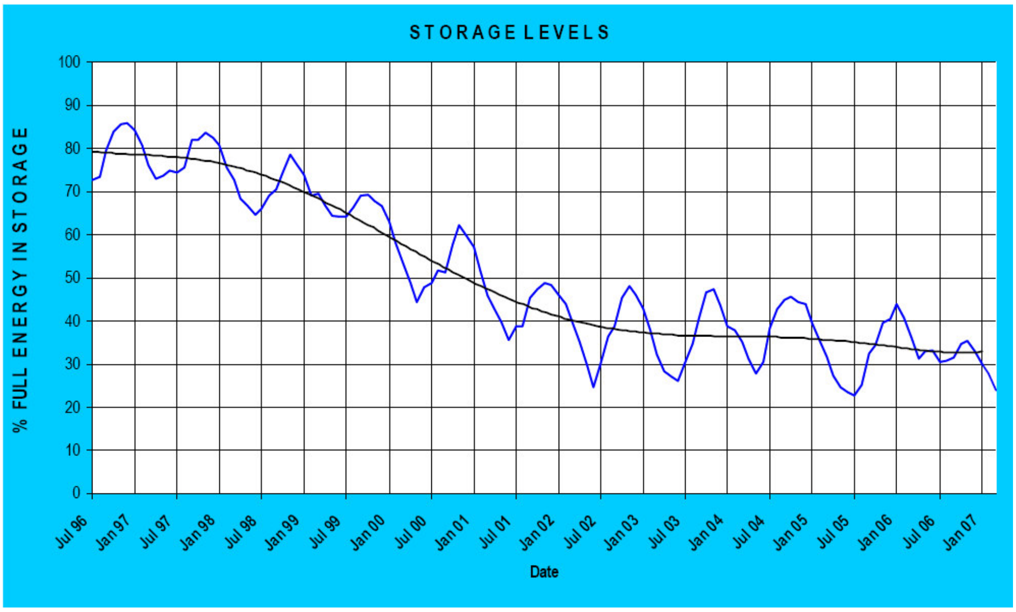

Figure 8: Hydro Tasmania storage levels - impact of drought[12]

Current climate models indicate little change in hydro inflows but considerable uncertainty remains in the modelling methods and data used. CSIRO predictions for climate change in Tasmania are shown in Table 6:

[12] Source: www.hydro.com.au

Climate parameter	Estimate	Uncertainty
Temperature	+ 1.1 °C	± 0.4 °C
Rainfall	+ 3.5%	± 11%
Evaporation	+ 4.4%	± 1.9%

Table 6: CSIRO predictions of climate changes in Tasmania 1990 to 2030[13]

The very high uncertainty in the rainfall prediction means it is worth exploring a wide range of possible scenarios for water inflows to hydro storages.

b. Wind

Wind power is emerging as a significant component of the Tasmanian power generation mix. Tasmania has some of the best wind resource in Australia and initial results show Tasmanian wind farms have substantially higher capacity factors than sites on the mainland. The prospects for wind power in Tasmania are summarised in Table 7:

Committed capacity	Woolnorth Bluff (65MW) – in service Woolnorth Studland Bay (75MW) – in service
Confirmed potential capacity	Musselroe (129MW) Heemskirk (160MW)
Potential ultimate capacity	Relevant considerations include: • Excellent wind resource in Tasmania's North-East, North-West, West Coast and Central Plateau • Immediate constraints are economic. Government Mandatory Renewable Energy Targets or similar schemes are necessary for investment to proceed in the short term. • Technical constraints due to the small scale of the Tasmanian system, such as system inertia (fast spinning reserve) and voltage control, are likely to increasingly limit long term development of the resource. However, technical solutions to these challenges may also emerge.

Table 7: Wind power in Tasmania

Scale economies in wind turbine manufacture are likely to progressively reduce wind power costs[14] to a long term level that is fully competitive with other generation options once carbon costs are included.

The unit cost of wind power in Australia is around $75/MWh, having fallen steadily from around $200/MWh when the industry started. The slight upward trend of the last few years is due to equipment supply/demand imbalance, rising steel prices, increasing labour costs and restructuring in the manufacturing industry and is considered likely to peak in a year or two. This is expected to be followed by resumption of the long term trend of increasing unit sizes and falling unit costs. In five to ten years, the unit cost of wind power in Tasmania may be as low as $60/MWh.

Most stakeholders felt that, provided the economics were favourable (through either government support or reduced manufacturing costs), Tasmania could support an ultimate

[13] Source: Climate change scenarios for initial assessment of risk in accordance with risk management guidance, Australian Greenhouse Office and CSIRO, 2006.

[14] Turbine costs typically constitute about 65% of total scheme costs

wind power capacity of between 600MW and 1000MW at around 40% capacity factor, assuming the present transmission system arrangements and load profiles.

c. Gas

Investment in gas power generation has emerged rapidly since commissioning of the Bass Strait gas pipeline. In the 12 months to April 2007, gas supplied 6% of total energy supply from two facilities:

- The 240MW Bell Bay power station which has been converted from oil to gas firing
- Three open circuit gas turbines at Bell Bay with a combined nameplate rating of 95MW.

The announcement of the Tamar Valley (Alinta) combined cycle gas turbine power station with an initial capacity of 260MW will increase this proportion further and introduce a second independent generator to Tasmania. In addition, the Gunns cogeneration facility is planned to have a net export capacity of up to 160MW. Both of these power stations are planned to connect to the transmission network at George Town substation.

The Bass Strait gas pipeline has capacity to support further gas generation, either in the North near where it comes onshore, or along either of the main spur pipelines which extend to Hobart and Burnie. If necessary, the pipeline’s capacity could be considerably increased through the use of compressors. In other broadly similar situations, pipeline compressors have increased flow by up to 50%.

The pipeline can be seen as a direct competitor for Bass Strait electricity transfer capacity, currently provided by Basslink. Until cable redundancy is available, direct competition between gas power investments on the mainland and similar investments in Tasmania may be constrained. Some stakeholders feel that if adequate secure link capacity is available, the preferred option may be to build gas power stations in Victoria and move the energy to Tasmania via the cables. However, whether this option prevails depends on the combined effect of many factors and commercial arrangements.

3. Environment

The treatment of carbon dioxide emissions by the power generation industry is one of the most prominent long term uncertainties facing the industry, because –

- Climate change has the potential to change electricity demand patterns towards a peakier load duration curve
- Government policy responses designed to manage carbon emissions have the potential to profoundly change the economics of the power industry (among others).

A number of resources were utilised in researching climate change and carbon policy as factors potentially affecting electricity transmission.[15] Identified key issues are summarised here.

[15] These include: Published reports on climate change and the economic effects of policy options (e.g. by CSIRO, IPCC); government reports on climate change and policy options (e.g. government Greenhouse Office papers and risk scenario reports); research commissioned by industry bodies such as the National Generators Forum and the CRC for Clean Coal and Sustainable Development and the CO2CRC.

In Australia, there is a vigorous political debate on possible approaches to the policy goal of carbon emission reductions, with most state governments stating their support for a cap-and-trade carbon emission trading scheme and the Australian government pointing out the potential economic risks and cost impacts of such a scheme and advocating investment in clean energy technology as an alternative.

However, the challenge for the electricity industry has recently been brought into much sharper relief by the nuclear power debate, as shown in Figure 9 which illustrates the challenge of meeting even the most conservative target now under discussion, i.e. maintaining emissions at current levels.

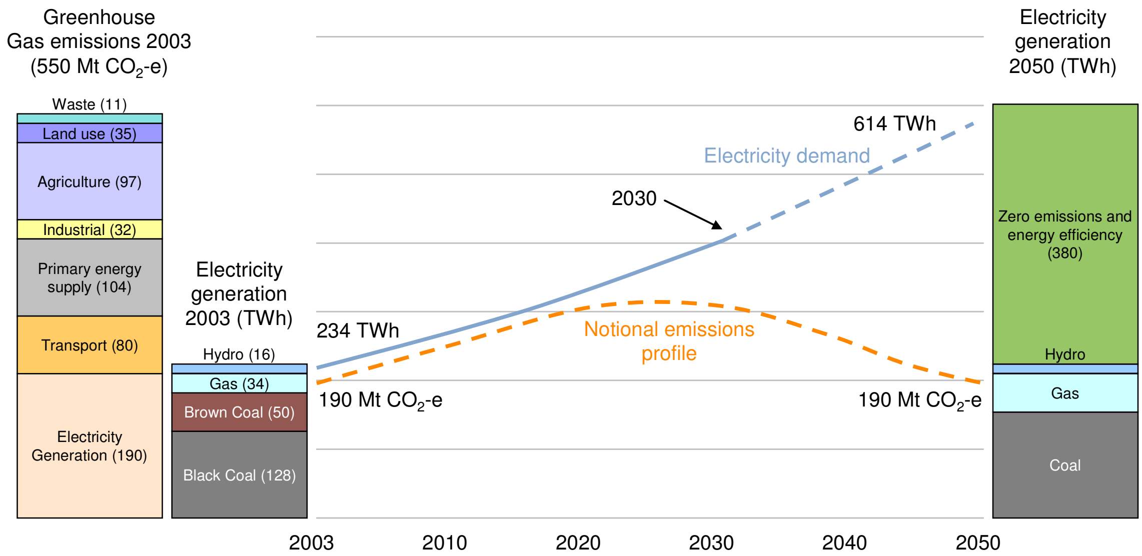

Figure 9: The climate change challenge for electricity in Australia[16]

If the industry is required to meet the demands of the Kyoto principles for developed nations (‘deep’ cuts in emissions by 2050), the challenge becomes extreme as shown in Figure 10. This indicates that investment in low and zero emissions power generation technology must, by 2050, deliver more than twice the total installed capacity of the entire NEM in 2003.

[16] Prime Minister & Cabinet, ‘Uranium Mining, Processing and Nuclear Energy Review’, Draft Report, November 2006.

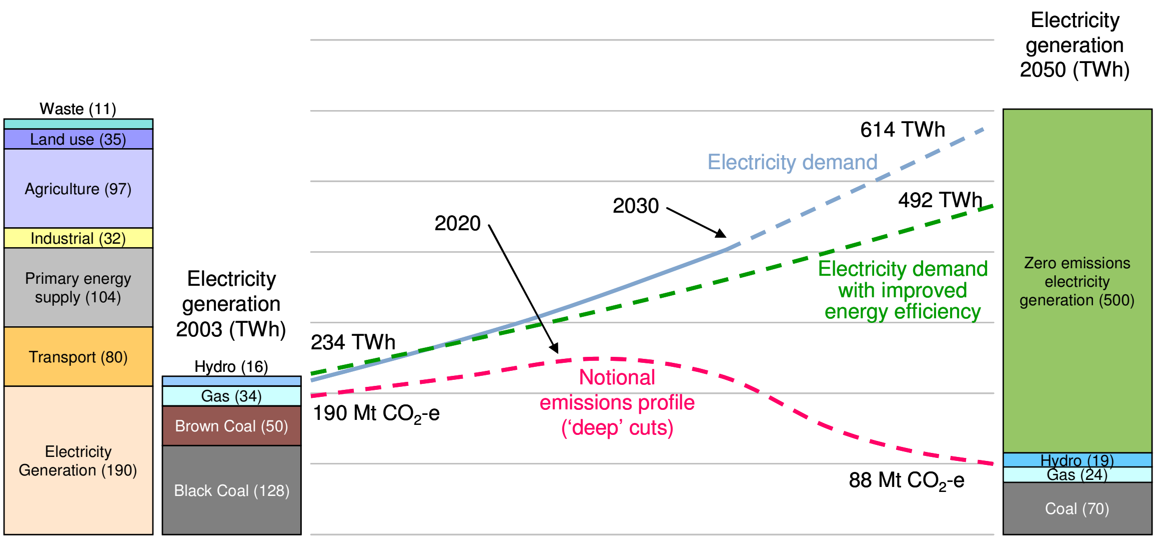

Figure 10: Australia's electricity generation and missions, a 2050 scenario[17]

Research conducted in 2004 used careful modelling to find the lowest cost means of meeting such a target, and indicated a carbon price of \$35-40/tonCO_2 must be added to the traditional comparative cost structures of generation options. An example of this 2004 data is shown in Figure 11.

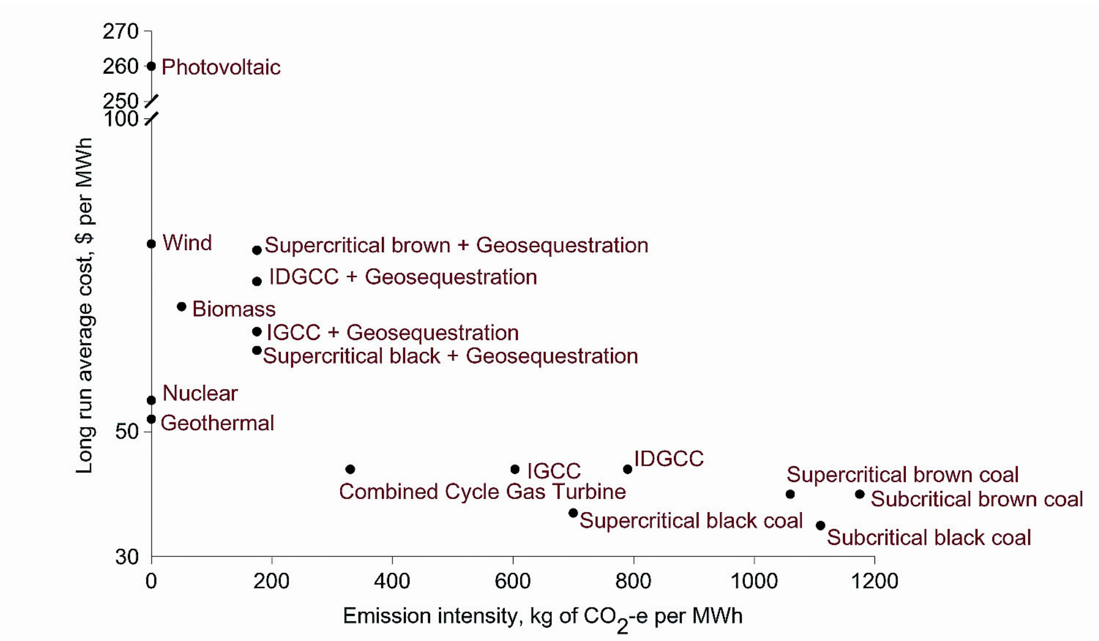

Figure 11: Electricity Generation - Indicative Costs and Emission Intensity by Fuel Source[18]

More recent research is focusing increasingly on more detailed analysis of relative economics of various power generation technologies, as illustrated by the 2006 data shown in Figure 12.

[17] AIE National Conference, November 2006 - DITR

[18] Allen Consulting Group – The Greenhouse Challenge for Energy, September 2004

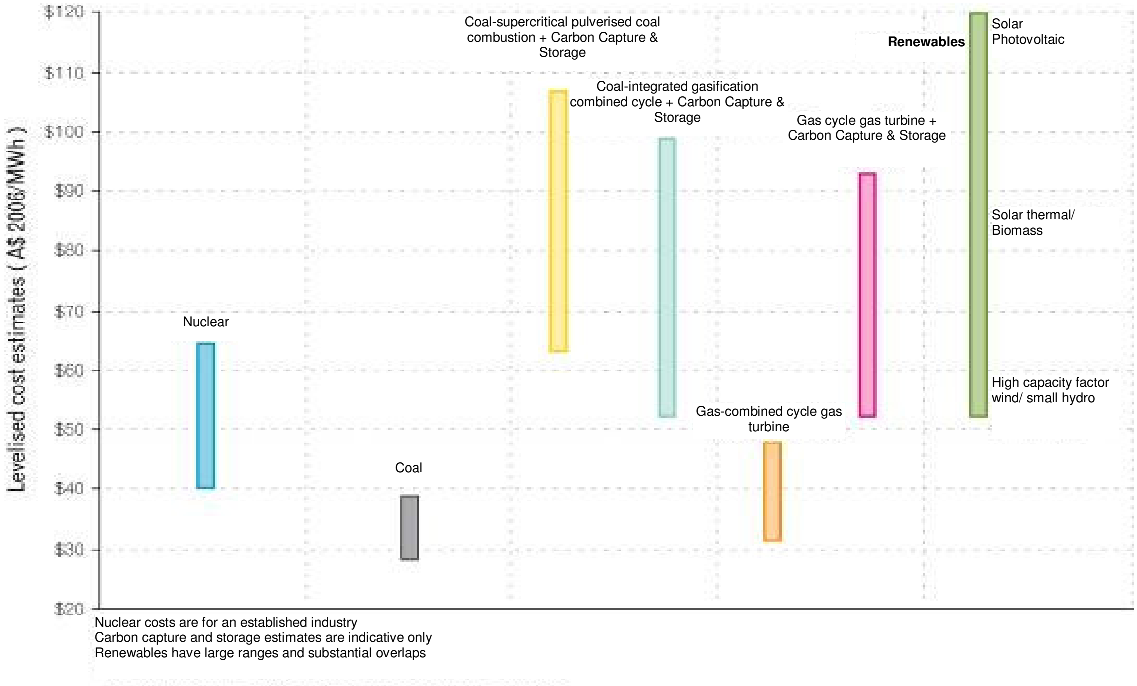

Figure 12: Relative electricity costs for various power generation technology options[19]

The impact of the changed cost relativities would be dramatic as indicated in Figure 13.

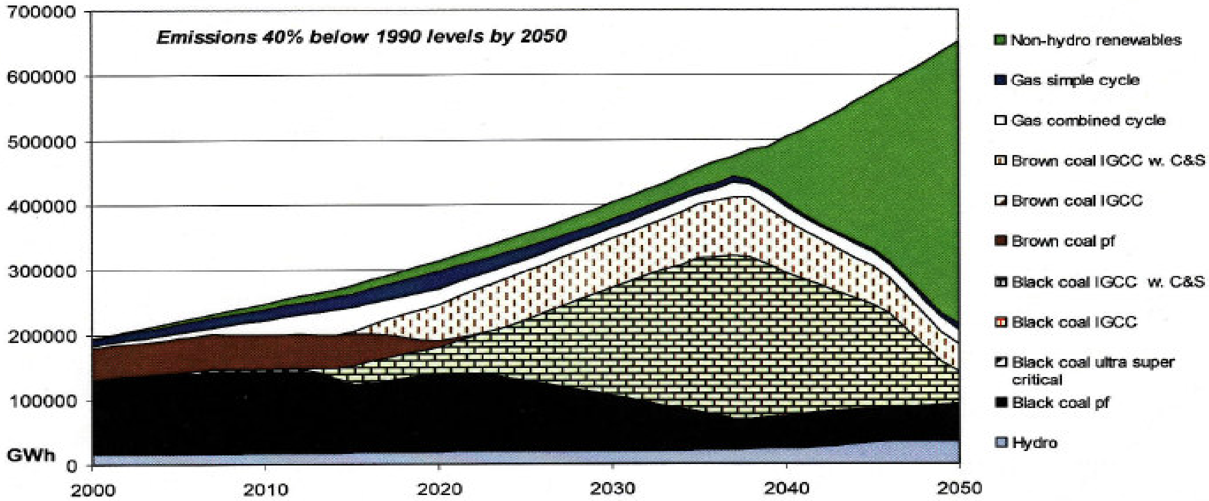

Figure 13: Simulated electricity generation portfolio for the 'emissions at 40% below 1990 levels by 2050' scenario[20]

Some current modelling indicates that the wholesale price of electricity may rise by 60% (best case) to 125% (worst case) to pay for the additional cost of zero emission plant. This has

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[19] EPRI for Prime Minister & Cabinet, 'Uranium Mining, Processing and Nuclear Energy Review', Draft Report, November 2006

[20] Cooperative Research Centre for Coal in Sustainable Development, 'Options for Electricity Generation in Australia', Technology Assessment Report 44, January 2005

obvious implications for NEM prices and the long term value of Tasmanian hydro and wind power, as these energy sources will not be subject to the cost increase that fossil fuel plants will experience.

4. Ownership

The recent Energy Reform Implementation Group (ERIG) report[21] identified appropriate ownership structures as a key determinant of industry efficiency via competitive market processes. The continuing direct government ownership and control of energy assets was reported to be a potential barrier in the achievement of a fully efficient economy.

The Tasmanian Government has legislated to retain electricity assets in public ownership. Most stakeholders considered that the majority of electricity assets will be transferred to the private sector at some time during the next 30+ years, with the possible exception of hydro generation due to public sensitivity associated with iconic construction projects and water rights.[22]

Many stakeholders feel that a merger of Transend and Aurora Energy's distribution business would increase overall business value and efficiency and is therefore likely, either before or after a sale of the two businesses. However, stakeholders consulted in this project felt that changes of ownership are not likely to have a material effect on projected energy market or network investment outcomes over the period.

5. Regulation

Most stakeholders considered that regulatory changes are unlikely to have a great effect on Transend. However, a number of issues are likely to be strongly influenced by regulatory policy settings:

a. A national planner for electricity transmission

The January 2007 recommendations from ERIG were broadly endorsed by COAG in April 2007 and implementation of a national transmission planning organisation is now certain. However, the precise role and powers of this new body are yet to be fully defined. The COAG decision specifically limited the new body's power to bind states to particular investment decisions. The effect of this new national function on Tasmania's transmission planning is not yet clear, especially in relation to the network reliability criteria recently developed by the Tasmanian regulator for use as formal reliability design standards in all Transend transmission projects.

b. Pressure on Transend revenue and performance targets

The relative generosity or severity of transmission revenue regulation is likely to continue to reflect market and community perceptions of the need for new infrastructure investment and the relative efficiency of transmission service providers. It is also likely to be influenced by demands from other sectors for priority when funds are scarce. Similarly, pressure on transmission service performance (security, reliability and quality of supply expectations) is

[21] Energy Reform Implementation Group Report January 2007: *Energy reform - the way forward for Australia* : www.erig.gov.au .

[22] Although the ERIG report notes that generation is the most important part of the electricity supply chain to privatise.

likely to get stronger over the long term. Many stakeholders felt that Transend may face real challenges in meeting market demands in this respect.

c. The future of inter-region links across Bass Strait

A key issue is: 'What policy settings (in the form of a benefits test) will apply to future investment in Bass Strait transfer capacity?' The benefits test is set by the Australian Energy Regulator for use by transmission owners. Whilst the AER approves the revenue of transmission service providers based on a specific forward investment plant, it does not directly apply the test to individual projects except in cases where a proposed investment is disputed by a market participant. The benefits test will influence the answers to two key questions:

i. Might Basslink be converted to a regulated asset?

Most stakeholders agree the current benefits test would not support conversion of Basslink to a regulated asset in the current market environment, at least not at a value close to its full construction cost. However, there are many factors that could bear on this question over the longer term. It is not clear that the benefits test will remain the same for 30+ years, nor how the different components of the tested benefits will be affected by climate change and other market changes over the period, nor even if Hydro Tasmania and its owner might be prepared in the short term to accept a lower regulated asset value in order to achieve (partial) sharing of ongoing costs with the mainland. The current reform direction towards national planning of inter-region links in the NEM will also have a bearing on how the answer to this question evolves.

ii. Might additional Bass Strait transfer capacity be justified?

Most stakeholders remain uncertain and even somewhat sceptical about further expansion of link capacity across Bass Strait. However, to enable Tasmanian hydro to supply its full peaking power capacity to the NEM, additional transfer capacity is likely to be necessary. Similarly, if Tasmanian hydro energy reserves contract significantly due to climate change, import of either gas for on-island gas power generation or electricity via an enhanced link capacity may be necessary. Taking all factors into account, it is difficult to entirely preclude the option that at some point in the next 30 years, additional transfer capacity across Bass Strait may be built.

6. NEM connection (Basslink)

Basslink was commissioned for full service on 28 April 2006 with a Southwards capacity of 480MW and a Northwards capacity of 600MW[23].

a. The benefits of Bass Strait power transfer

The benefits of Basslink to the State include:

i. Drought-proofing Tasmania's electricity supply – a benefit that has been very apparent since implementation. Hydro Tasmania states that without Basslink, storages would be 6% lower than they are currently (The Great Lake would be virtually emptied of useable water), Tasmania would be facing the prospect of power rationing and potential blackouts in the 2007 winter and Hydro Tasmania

[23] The northwards capacity is a short term (6 hour) rating. The link must operate at no more than 300MW for at least four hours prior to use at 600MW.

would be paying for much greater quantities of gas at a generally higher cost than Basslink imports.

ii. Provision of national market access for hydro and wind power generators in Tasmania. Tasmanian hydro nameplate capacity is of similar scale to that of Snowy Hydro, but Tasmania's isolation until now has precluded realisation of the full value of its hydro assets in the NEM context.

iii. Improved flexibility of hydro generator operation to reduce spillage and so get more value from the water in storages. When water spillage is imminent and local load is insufficient to absorb more generation, the water that would have spilled can be run through the generators and the produced power can be exported to the NEM.

iv. Market price arbitrage between Tasmania and Victoria. However, to cover the full operating cost (thought to be around $240,000 per day average) by this means would imply full capacity of 400MW x 24 hours X 365 days @ $25.00/MWh price difference, so arbitrage is clearly not a sufficient funding mechanism alone in current market conditions.

b. Significant long term issues

There are two characteristics of Basslink that are of long term significance: Firstly, it is a single link and can be lost in a single event, so security of connection is an important consideration for inter-regional trade. Secondly, its capacity is much lower than would be required to use Tasmanian hydro as a major peaking provider in a similar way to mainland hydro stations.

The financial risks involved in electricity trading across inter-regional links subject to congestion constraints are sometimes managed by the NEM's quarterly auctions of inter-regional settlement residues. However the forward market in rights to these residues is thin and rarely extends forward more than 12-18 months, which is far less time than would be required to hedge a typical supply contract. If the market design is changed to address this issue, the new arrangements would have direct application to Basslink trading and risk.

The NEM is currently designed to function as a collection of linked regional markets. If Bass Strait transfer capacity is increased, it may exacerbate the already recognised issue of Victoria, Tasmania and South Australia starting to behave more like a single region. Design changes in market processes may be required to address such a development.

c. Opportunities for Tasmania

There are a number of possible drivers of opportunities to import or export more power to and from the mainland. Reduced water inflows through climate change could lead to increased reliance on mainland power and therefore, a need for increased import capacity and security. Conversely, the departure of major industrial loads could lead to a supply/demand imbalance and an opportunity to export more power.

In addition, there are two relatively independent opportunities to realise higher value from Tasmanian hydro and wind power:

i. Exploit higher NEM prices that may arise in a carbon management regime.

The value of this opportunity is expected to attach equally to every MWh delivered to the market, i.e. time of delivery is not critical. However the energy may need to be moved across

Bass Strait, so the capacity of the link could be a key determinant of the extent to which this can be done.

ii. Exploit premium NEM prices, including in peak demand periods.

Climate change may preserve the peakiness of the NEM load duration curve or make it even peakier if major energy intensive industries depart Australia. Further, it must be recognised that nationally, hydro is unlikely to continue to expand as the market expands and it will be an increasingly scarce resource as the market grows. Hydro's flexibility, its 'clean green' character, and its increasing scarcity (both due to its declining share of the total market and possibly due to climate change impacts on inflows on the mainland), may all contribute to a further value opportunity for Tasmanian hydro power. The ability to obtain higher value for Tasmanian power during NEM peak periods will depend very directly on the Northwards transfer capacity across Bass Strait which would almost certainly have to be increased beyond current levels.

F. Potential transmission network capacity requirements

1. The scenario planning approach

To extend the thinking of both internal and external stakeholders about what Transend's operating environment might look like in 30+ years and what the consequential demands on the transmission network might be, the vision project developed four scenarios based on groups of potential influencing factors to more vividly create possible transmission futures.

In particular, the scenarios were deliberately designed to 'push' management and technical thinking by creating possible outcomes that would place challenging demands on the business. Scenarios are not predictions of what will happen, or even what is likely to happen – at least, not in that exact form. Instead, the scenarios 'explore the boundaries of reasonable credibility' as illustrated in Figure 14:

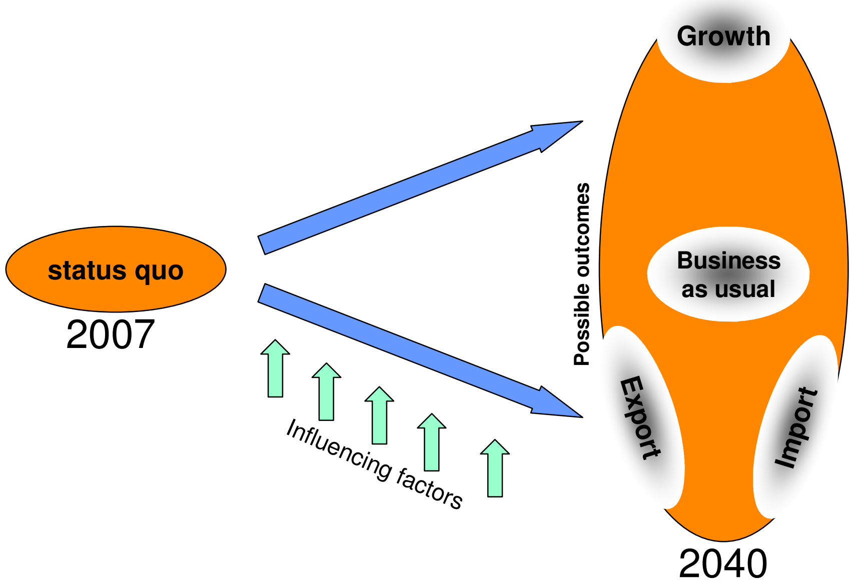

Figure 14: Scenarios to explore the range of possible 2040 network needs

The scenarios tested factors such as:

- Climate change effects
- Carbon price levels
- Population projections
- Demand growth, both peak demand and total energy requirements
- Presence or absence of major industrial customers
- Generation type and locations
- Transfer capacity across Bass Strait
- Growth rate of the Tasmanian economy
- Ownership of Transend and relationship with Aurora Energy's network business
- Skills availability
- Energy prices
- Consumer attitudes

In each scenario, the active influencing factors were selected to create a reasonably credible overall picture, but also to create tension by applying conflicting pressures on Transend's network business.

Three assumptions were made in constructing the scenarios:

a. Each scenario should contain 'internal tensions' between environmental, demand, supply, community and ownership factors

b. The influencing factors with most impact on the 30 year scenarios will be environmental (especially climate change and carbon management), demand and supply factors

c. Technology developments will have their most relevance in thinking about the possible business responses open to Transend, rather than shaping the scenarios themselves.

The four scenarios used were:

'Growth': a range of factors lead to much greater demand growth than is currently foreseen

'Export': a range of factors lead to much of the Tasmanian electricity industry being directed towards export of 'green' peaking power to the mainland NEM regions via increased Bass Strait transfer capacity

'Import': a range of factors lead to Tasmania relying on electricity imports from the mainland via increased Bass Strait transfer capacity

'Business as usual': Tasmania's current situation continues with only slow incremental growth in demand and no significant discontinuities in the operating circumstances of the network business

The scenarios drew upon information gathered from research by the team and in stakeholder interviews. They were reviewed in workshops of internal and external stakeholders. A detailed description of the scenario planning approach is outlined in Appendix 4 and descriptions of the four scenarios are set out in Appendix 2.

2. Modelling of network development needs

The three scenarios that represented major change from today's conditions (import, export and growth) were used as the basis of network modelling to identify what development projects may be required.

The 'business as usual' scenario was not modelled. However, it should be recognised that continuing capital investment will be required even in this scenario to replace ageing transmission assets and augment the network to respond to (slower) growth in demand. However, under this scenario there are fewer major 'step changes' in network development. Overall, this scenario is considered likely to present challenges that fall within and would be adequately covered by, consideration of the other three scenarios.

For each scenario, key assumptions were defined (see Table 8) and possible Year 2040 demand and generation patterns (see Table 9) were developed for use in the network modelling.

Scenario			Key assumptions
Scenario	Growth	Demand	• Industrial development in the North West and increased industrial load North and South • State wide population increase drives domestic and general demand growth
		Supply	• Gas generation close to gas supply and load centres in North West, North and South • Spare Gordon hydro turbine position(s) used
	Export	Demand	• Tasmania's demand growth is low • Bass Strait link capacity increased to supply mainland market with green peak power
		Supply	• Renewable sources favoured, hence major wind power development (800MW total) • Spare Gordon hydro turbine position(s) used
	Import	Demand	• Tasmania's demand growth is medium • Industrial development is limited
		Supply	• Mainland power price is low, inhibiting investment in local generation in Tasmania • Minimal new wind power or new gas generation, second Bass Strait link for redundancy

Table 8: High level summary of key assumptions used in modelling each scenario

These assumptions lead to the demand and generation profiles summarised in Table 9:

		Region	Scenario		
			Growth	Export	Import
Demand (existing + new)		West Coast	300	40	60
		North West	1,000	350	430
		George Town	800	350	480
		North	780	420	630
		South	1,620	1,290	1,400
		Total	**4,500**	**3,450**	**3,000**
Generation	New (by 2040)	North West (wind)	235	240	-
		West (wind)	-	160	-
		North East (wind)	-	200	75
		Central (wind)	-	200	-
		North West (gas)	400	-	-
		North (gas)	860	-	320
		South (gas)	300	200	-
		South West (hydro)	225	260	-
	Existing		2,680	2,680	2,680
		Total	**4,700**	**3,940**	**3,075**

Table 9: Demand and generation scenarios (MW)

In Table 9, the generation capacity shown is the total installed capacity. However, the system modelling has been based on the capacity available for normal NEM dispatch which can be significantly lower in the case of wind power and cogeneration than the figures shown.

Possible development profiles for energy consumption, demand and generation were derived as summarised in Figure 15:

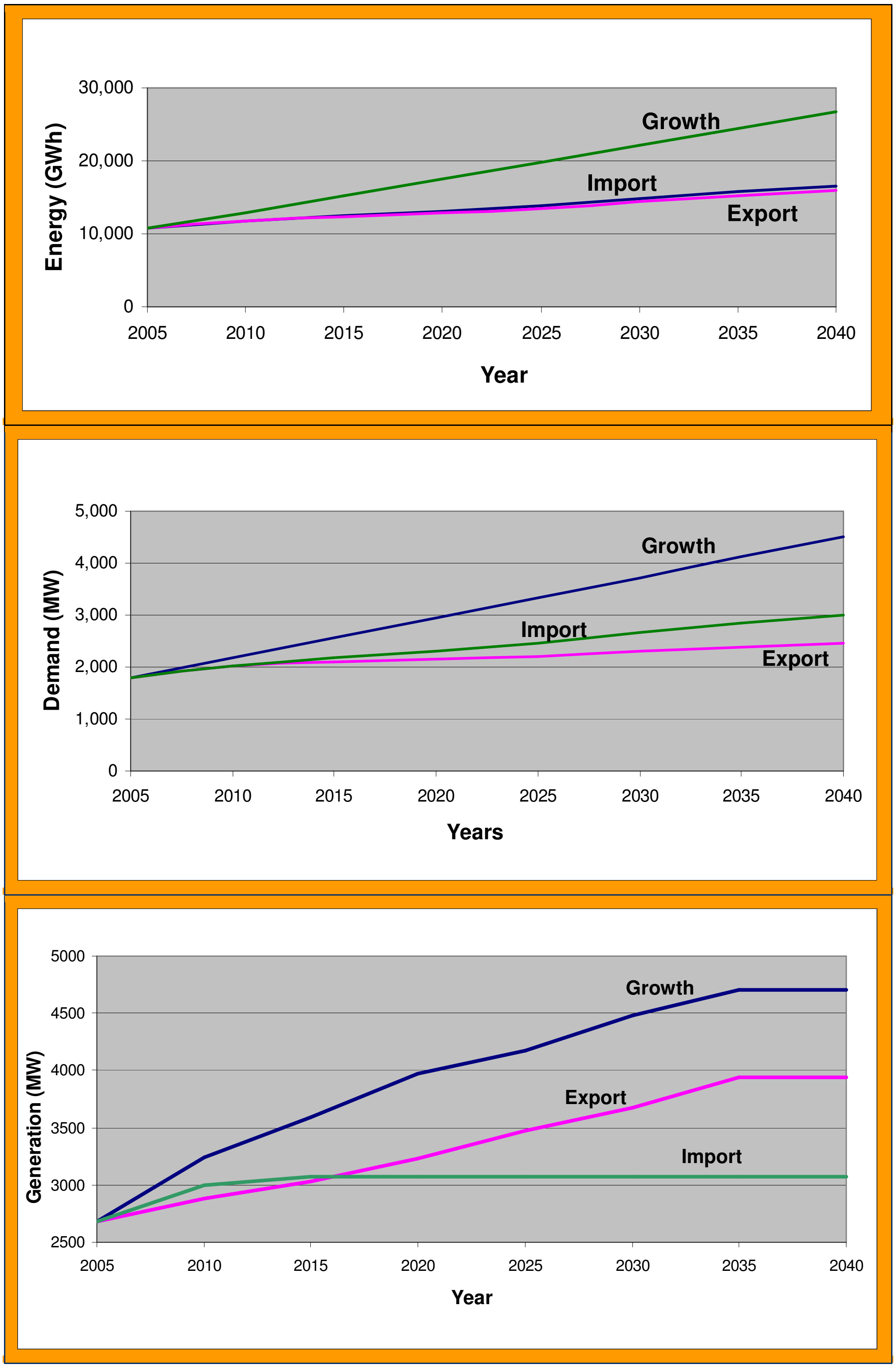

Figure 15: Scenario modelling - summary parameters

Based on these sets of data, system studies were undertaken to identify the potential development requirements for the network in each of the scenarios.

The system studies identified a number of locations in which network constraints were likely to emerge (or are already evident), as summarised in Table 10:

Location	Description	Possible timing
Palmerston to Chapel Street[24]	220kV lines overload	Pre-2010
Sheffield to George Town	Line capacity increasingly exceeded during high southwards flow	Pre-2010
Waddamana to Lindisfarne	Supply to Hobart region requires second 220kV line and reactive support	2015
Sheffield to Burnie	110kV line overload as demand grows in the North West	2015
North West	110kV to 220kV upgrade and new supply point to supply regional demand	2020
North-South backbone	New line capacity needed to support voltage during southwards flow	2020
Palmerston to Liapootah	Line overload and voltage stability issues during southwards flow	2020
George Town to Hadspen	Distortion of market dispatch under light load and northwards flow (export)	2020
East Coast supply network	Additional lines needed to support demand	Uncertain
Sheffield to Burnie	Overload of 220kV line requires additional line	2025
Basslink upgrade or duplicate	Numerous issues depending on point of connection	Uncertain

Table 10: Possible transmission network constraints to 2040

In summary, line loadings on the core 220kV network are increasing to the point that network constraints in the Southern portion of the network may impact before 2010. After that, additional constraints to the South of Palmerston may need to be addressed by 2015 and 2020. Then the Palmerston to Waddamana section of the 220 kV network may require additional lines by 2025. Possible constraints in the West Coast area, Northern region and East Coast may require new lines, with timing dependent on local demand growth.

[24] This constraint is the focus of a proposal to build a new 220kV line from Waddamana to Lindisfarne by 2010.

G. Potential transmission network development

The scenario planning approach identified a range of possible network constraints that may require investment in additional lines or upgrades of existing lines. These projects are in addition to projects needed to replace ageing assets at the end of their service lives.

Given the range and diversity of network projects that that are likely over the next 30+ years, a strategic approach is essential. Piecemeal treatment of each project without consideration of overall strategy would be likely to produce unwanted outcomes for stakeholders in the form of suboptimal prices and service reliability levels.

The system modelling identified a number of strategic issues that will require resolution in order for long term network development to deliver the optimum result for stakeholders. These are illustrated in Figure 16 below. The issues are:

1. Strategy for the network backbone
2. Strategy for major load centres
3. Strategy for North West & West Coast
4. Strategy for the East Coast

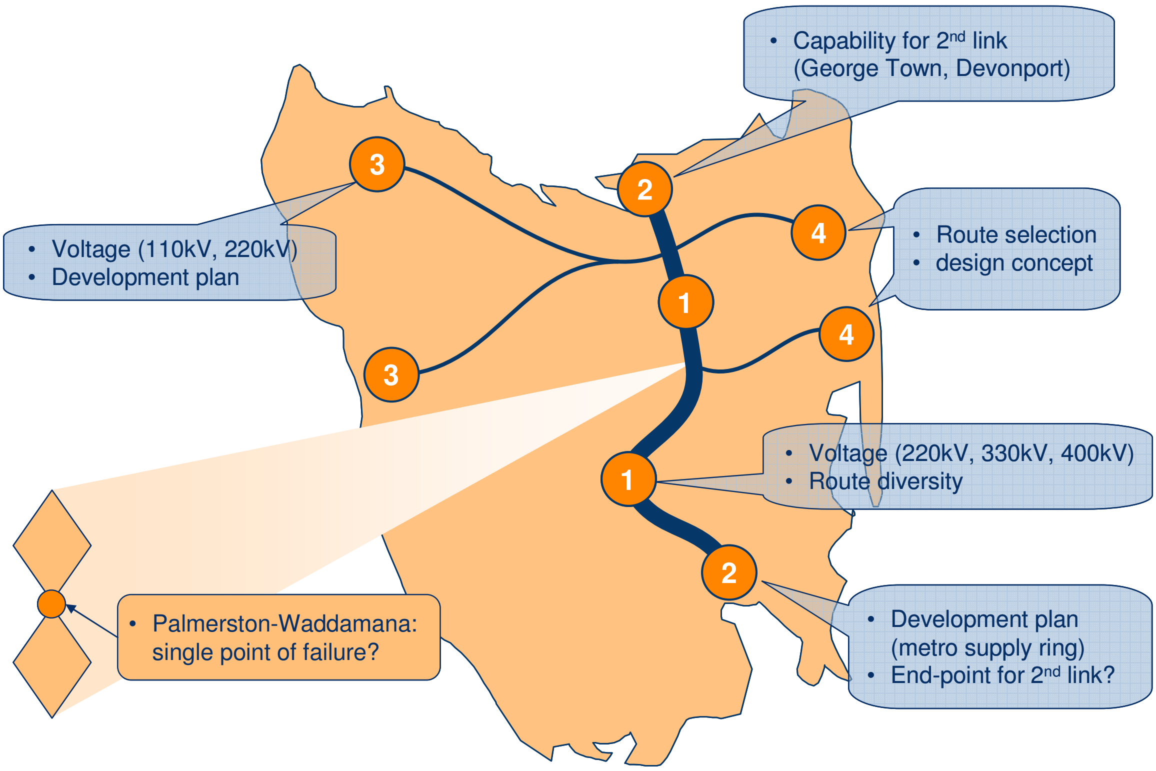

Figure 16: Strategic issues in long term transmission network development

The four long term strategic issues must be considered in the light of other governance and regulatory structures that exist, especially the reliability based network planning criteria set by the Tasmanian regulator.

1. Strategy for the transmission network 'backbone'

There are two strategic issues which must be resolved in the long term development of the North-South transmission network backbone:

a. Backbone network route diversity:

Redundancy of transmission line routes is important in preservation of supply against major disturbances. The major supply interruptions in Victoria on 16 January 2007, which were caused by simultaneous loss of multiple lines in a single easement due to a bushfire, vividly illustrate this point.

In Tasmania, the main North-South network backbone has good potential for route diversity North of Palmerston and South of Waddamana (assuming the proposed line from Waddamana to Lindisfarne is built). However, Palmerston and Waddamana substations and the single transmission line easement that runs between them are elements of the transmission system that will remain potential single points of failure.

In this situation, a suitable strategy might be:

i. Preserve and continue to develop appropriate redundancy of transmission corridors North of Palmerston and South of Waddamana

ii. Design Palmerston and Waddamana substations and the lines between them to a high level of reliability and security against major events that could potentially cause a 'single cause, multiple contingency' failure.

b. Backbone network voltage level:

Continued development of the North-South backbone network could be done at any one of a number of different voltage levels. Optimum results will flow from careful choice of a target voltage level for this corridor that best suits the network's long term needs. Options include 220kV, 275kV, 330kV, 400kV and 500kV and a detailed study is warranted to identify the option that will provide optimum outcomes in terms of overall transmission prices, reliability and flexibility.

Continued investment in 220kV technology may produce undesirable and inefficient multiplicity of parallel lines in many of the existing easements even though it would contribute some network redundancy. The construction of 220kV lines to suit later refit for operation at higher voltage levels may involve a relatively low initial cost premium and if so, this may be a prudent investment in future flexibility. However, current projects should proceed as planned (for example, the proposed Waddamanna-Lindisfarne 220kV line).

The issue of selection of the optimum voltage to meet long term needs is considered further in Section 5 below.

2. Strategy for the major load centres – North and South

Tasmania's two major demand centres pose slightly different strategic issues than those raised by the backbone network. The two issues of strategic significance are:

a. Metropolitan supply ring development:

A network development plan is required for a supply ring (or equivalent) to provide the redundancy necessary for reliable supply to major customers in the Hobart area and to the commercial centre. Production of this plan should be done in conjunction with Aurora Energy and local planning authorities. It should take into account modern transmission technology options that offer opportunities for incorporation of transmission assets into the built environment of high density urban development areas.

b. Options for connection of second Bass Strait link:

The long term period to 2040 may see augmentation of Bass Strait transfer capacity in the form of a second cable link. This may arise from factors such as those listed in the import and export scenarios. Transend would play a key role in conjunction with national transmission planning bodies to develop the optimum solution for connection of this link into the Tasmanian transmission network. Options centre on areas close the major load centres, viz. Northern locations such as Burnie, Devonport or George Town or alternatively, closer to Hobart (the link could be brought south from the cable landing point via an overhead DC line). For this reason, it may be prudent to include consideration of this issue in development plans for the major load centres. There are many factors that would determine the optimum solution, but development plans for both these areas should include consideration of possible future requirements to connect a link of up to 1,000MW capacity securely into the local transmission network.

3. Strategy for the North-West Coast and West Coast

The 110kV transmission spur that extends from the backbone network at Sheffield substation across to Burnie and Port Latta substations, and ultimately to the wind farms at Woolnorth, will require upgrading if either (or both) local wind power investment or regional industrial development significantly increases. Requirements may also include possible wind generation and mineral development sites on the West Coast. A development plan for this area of the network is required that amongst other things, defines the voltage level for future developments. The basic decision will be whether to continue with the existing 110kV design or upgrade to 220kV. Detailed studies are likely to be required to fully resolve this choice. The technical concept can be defined to meet a particular level of demand and/or generation independent of considerations of funding of the actual investment.

The plan should be developed in conjunction with external planning authorities and take into account the views of potential wind power investors and operators. Existing easement routes are likely to suffice.

4. Strategy for the East Coast

The strategic approach to transmission supply to the East Coast requires production of a design concept and development plan ahead of the actual needs so that any necessary easement acquisitions can proceed in time to meet the normal long lead times required for planning approvals.

Of the many options for long term augmentation of supply to the East Coast, no single option has compelling justification for adoption compared to any of the others:

i. Existing spur lines could be upgraded to double circuit construction or additional lines could be built in the same easements.

ii. Alternatively, the three spurs connecting Triabunna, St Marys and Derby substations to the network backbone could be reinforced by a line running parallel to the coast connecting any two or all of these locations.

Detailed studies are required to asses the options for feasibility and comparative benefits in terms of reliability and costs. These studies must involve local planning authorities, especially where new easements are involved.

The objective of the studies would be to produce a development ‘road map’ (design concept plus notional development plan) for increased supply to the East Coast, so that action can be taken quickly should a need arise at short notice, while still protecting overall strategic objectives of efficiency and reliability. This need applies in all regions, but the challenges in development of such a ‘road map’ are perhaps greatest for the East Coast.

5. Choice of backbone voltage level

The choice of backbone voltage level will depend on a number of factors, but three are of particular importance:

i. Efficient use of easements, i.e. minimum net increase in line length and number of circuits in each easement. This benefit must be offset by the limited redundancy benefit from a smaller number of parallel circuits in each easement.

ii. Low long term costs, as reflected in transmission service prices to customers. Whilst this will be dependent on a number of factors such as load-duration curve and demand growth rate, a strategic choice can be made through careful modelling and sensitivity testing against variation in key quantities.

iii. Flexibility so development remains efficient with variations in demand growth, i.e. without under-utilisation of assets and consequent higher prices. Each option should be assessed for its flexibility to match investment to demand growth rate to avoid price volatility over time, e.g. substation upgrades tend to be expensive single blocks of investment, whereas line upgraded may be split between initial construction to support a later refit to operate at a higher voltage.

Other factors such as the level of reactive support required and levels of system losses will tend to favour higher voltages. However, these issues can generally be managed at relatively lower cost and with lesser environmental impact, so they tend not to drive the selection of voltage level in networks of the scale of Tasmania’s.

Potentially suitable options include:

220kV: Already in use in Tasmania and used widely in Victoria and some other states

275kV: Extensively used in some mainland states

330kV: Used widely in NSW and Queensland and in some major links in Victoria

400kV: Used in many major transmission networks globally, e.g. widely in the UK

Higher voltage options are likely to be too big a jump from the status quo (e.g. 500kV) given the small size of the Tasmanian network and its limited capacity to absorb major disturbances resulting from sudden loss of a line.

Transend has commenced some preliminary investigations which are providing early indications that a voltage higher than the current 220kV may provide the best overall solution. However, Transend should conduct further, detailed investigations to test these preliminary conclusions.

H. Recommendations

This vision lays out some potential views of the environment for electricity transmission in Tasmania over the next 30 years. As events unfold, Transend will need to act to ensure that it is shaping outcomes rather than just responding to them. The process of developing this vision has provided some clear indicators of directions that Transend should prioritise - in the development of the transmission network; in specific business capabilities the company will need to meet its challenges; and in how Transend should use the network vision itself to support its revenue application and its longer term positioning in the industry.

It is the nature of projects like this that they lead to more detailed work in areas of strategic significance that they identify, i.e. they help define the business and network planning agenda. It is recommended that Transend initiate further action in each of the following areas:

1. Transmission network development

The system studies undertaken as part of this vision development project have identified strategic issues and included some preliminary investigations. However, to effectively address the strategic issues in long term network development, Transend should initiate more detailed planning studies to:

i. Develop a 'generation resource' map, to investigate in more detail the likely potential locations of new or upgraded generation sources

ii. Select the optimum voltage for future backbone network development

iii. Produce development plans for the Hobart, West and North West regions

iv. Produce a design concept and development plan for the East Coast region

v. Identify options to ensure capability to connect a second mainland link

These studies should be done in conjunction with stakeholders wherever possible to build Transend's credentials as a key industry planner. The objective is to prepare development 'road maps' so that action can be taken quickly when needs arise at short notice, without compromising overall strategy objectives of efficiency and reliability.

Transend should remain involved in implementation planning of recent COAG decisions to set up a national transmission planner, so that its internal planning activity can mesh with new national arrangements as they emerge.

2. Making the most of this vision

The benefits of this network vision lie not only in the outcomes of the thinking undertaken, but also in the process of engagement that the project has employed. It's important that Transend builds upon that level of engagement with internal and external stakeholders, and the vision is a useful tool. We would recommend that following consideration of this project report by the Transend Board, a next step should be to develop a 'public consultation' vision document that could be used to support public consultation leading up to the next revenue application.

Decisions on what should be included in the public consultation vision document will of course need to be considered and discussed. However, we would recommend a structure broadly based on this report, but modified to be more accessible for a wider range of stakeholders. The structure might look something like:

A. Executive summary

B. Transend's role in the electricity supply chain

C. What stakeholders require from Transend

D. The Tasmanian energy market – current context

E. Factors that will shape transmission development

F. Potential network capacity requirements

G. How the Tasmanian transmission network might develop to meet requirements

H. Conclusion

The Nous Group would recommend a wide ranging consultation process which draws on the vision not to define specific capital investments; but rather to inform stakeholders of the long-term context for the specific proposals in the next revenue application and to garner support for them.

I. Conclusion

This network vision does not set out exact paths for development of the transmission network over the next 30+ years – it is simply not possible to accurately forecast developments in demand and generation patterns over that time frame. However, it does help to define the boundaries of how the network might develop, to highlight potential constraints and issues and point to the development options that might need to be investigated further.

Transend's revenue application requires a five year firm investment plan based on a ten year indicative network development plan. However, the 45+ year life of transmission assets makes it important to place these plans in a strategic context that will drive investment decisions over the long term. As well as providing this context, the work completed in the development of this network vision provides a basis for more detailed investigations, planning and costing, so Transend is well prepared to respond to a range of possible outcomes in the Tasmanian energy market.

The development of this vision has been a constructive process for Transend – both in terms of positive engagement with key external stakeholders, and productive involvement of internal management and staff. The vision has further potential value as a basis for building more effective relationships with a range of external stakeholders, opening dialogues with them, and involving them more directly in planning processes. The opportunity is there for Transend to take this network vision, develop a public version of it, and employ it as a vehicle for consultation and engagement to help the organisation move forward in concert with its stakeholders.

Appendix 1 NIEIR demand forecast report

(**note:** Tables and Figure numbering throughout this Appendix are specific to the NIEIR report – numbering in this project report resumes from Appendix 2)

Energy scenarios for Tasmania to 2040

A report for the
Transend Networks Pty Ltd

Prepared by the
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trading as National Economics
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October 2006

While the National Institute endeavours to provide reliable forecasts and believes the material is accurate it will not be liable for any claim by any party acting on such information.

Contents

List of tables

List of figures

1. Introduction

Transend Networks requested the National Institute of Economic and Industry Research (NIEIR) to prepare long run projections of Tasmanian energy and maximum electrical demands to 2040.

NIEIR currently prepares energy and peak electrical demand forecasts out 15 years for Transend Networks. These projections are used in Transend Networks' Annual Planning Review and also as an input into the NEMMCO Statement of Opportunities for the National Electricity Market (NEM).

It should be acknowledged that the projections developed in this report were not derived from an extensive or exhaustive modelling process. They are consistent with the scenario assumptions and provide a mix of indicative outcomes to 2040 for Tasmanian energy.

The study scope for projections of energy and demand for Tasmania to 2040 is reproduced below.

The work involved the development of three scenarios. That is:

(i) a business-as-usual scenario (BAU);

(ii) a mild intervention scenario; and

(iii) a stringent intervention scenario.

The BAU scenario will basically incorporate current greenhouse policy. The mild and stringent scenarios will incorporate policies in the areas of greenhouse gas abatement (e.g. emissions trading), additional MEPs [Minimum Energy Performance Standards], peak load pricing and direct load control. Each of these will have varying impacts on wholesale and retail prices.

The analysis will also consider additional renewables and gas fired generation in electricity production and direct gas use for heating (process, hot water, space). Restrictions on wood usage may also be included in the intervention scenarios, on pollution grounds.

The output includes a report documenting the various scenario assumptions to 2040. The projections of energy will include electricity and gas energy, as well as maximum electricity demands. The forecasts are reported for 2010, 2015, 2020, 2025, 2030 and 2040.

Section 2 of this report outlines the key methodological assumptions underlying the three scenarios developed for the projections.

Section 3 tabulates forecasts of electrical energy to 2040 under each scenario. Maximum demand forecasts are also presented in this section.

Section 4 presents projections of natural gas usage to 2040 for Tasmania, again by scenario.

2. The scenario assumptions for long run projections of Tasmanian energy and maximum demands

2.1 Introduction

This section outlines the assumptions underlying the projections of energy for Tasmania for the three scenarios developed. These are as follows:

- a business-as-usual (BAU) projection;
- a mild intervention scenario; and
- a stringent intervention scenario.

2.2 The business-as-usual (BAU) scenario

Table 2.1 presents a summary of the growth in Tasmanian population, gross state product and the dwelling stock to 2040.

Table 2.1 Tasmanian GSP, population and dwelling stock growth – five year spans to 2040 – BAU

	Compound growth rate (per cent)		
	Gross state product	Population	Dwelling stock
2005-2010	2.6	0.4	0.8
2010-2015	1.7	0.2	0.8
2015-2020	1.6	0.1	0.6
2020-2025	1.5	0.2	0.6
2025-2030	1.9	0.4	1.0
2030-2035	1.6	0.3	0.8
2035-2040	1.5	0.2	0.6
2005-2040	1.7	0.3	0.7

As indicated in Table 2.1, Tasmanian GSP averages 1.7 per cent growth per annum over the 35 years to 2040. Population growth over the same period averages 0.3 per cent per annum.

In level terms, Tasmanian GSP rises by 80 per cent over the 35 year period. Population in Tasmania rises by nearly 50,000 persons.

Energy and energy policy assumptions

- Current greenhouse policy, that is no specific carbon signal (ETS, carbon tax), over the 2005-2040 period.
- No MEPS changes, no peak/off-peak (tou) tariffs, no interval meter installations.
- NIEIR projections of Tasmanian energy supply and demand out to 2040, covering:
  - generation (hydro, gas, wind: no expansion in BAU as MRET saturated). No hydro expansion, no Basslink expansion in Tasmania;
  - net imports via Basslink (on average runs at 75 per cent capacity each year, but runs at close to capacity from 2010 on);
  - electricity demands by sector;
  - non-electricity energy supply (gas, biomass); and
  - non-electricity energy demands.

Gas electricity generation in Tasmania

Under BAU there is a gas generation expansion at Bell Bay and potentially at other sites (CCGT, OCGT and cogeneration) because with hydro capacity constrained (no further developments, some upgrading), and no expansion of Basslink (running at full capacity from 2010), gas is the only alternative to meet increasing electricity demands.

Basslink

Subject to water availability and Basslink capacity, exports to Victoria expand over 2006-2010 to supply Victorian peak demands at prices competitive with gas fired peaking plants in Victoria. In milder months when Victorian daily demands fall to levels that can be supplied competitively by Victorian brown coal plants and black coal imports into Victoria, Tasmanian exports drop and imports rise.

Imports to Tasmania from Victoria occur when there is spare capacity in Victoria, when Tasmanian prices are higher than alternative Victorian exports to South Australia and New South Wales, and when Basslink is not constrained.

When Basslink South capacity is reached, and when Tasmanian demand exceeds import, Tasmanian hydro and wind capacities, electricity prices rise to bring on gas generation from Bell Bay and other sites.

New generators enter the Victorian and Tasmanian markets if expected prices can provide reasonable returns for the new generators. In the case of new Victorian generators, this will include expected returns from Victorian and export markets.

Gas generation expansion in Tasmania will occur when expected returns, in the capacity (Basslink, hydro, wind, existing gas) constraint case, are adequate from increasing Tasmanian demands.

With electricity supply in Tasmania constrained (existing capacity, hydro, imports) some electricity demand could switch to gas, biomass and solar: for example in water heating and space heating.

Sensitivities

- Industry trends: aluminium, TEMCO, pulp and paper retained at current levels.
- Household growth rates are provided above.
- Gas penetration (non-electricity generation) and prices: winter peak – assumes gas penetration increases moderately in the residential sector.
- Air conditioning split-system penetration (approximately 20 per cent in 2005: ABS 4602) continues to rise slowly reaching 30 per cent by 2020 and 40 per cent by 2040.
- Peak/off-peak demand (MW) and energy (GWhs).
- Wood heating trends (currently, 2005, 44 per cent of space heating): Tasmanian Office of Energy (Tony Beamont 03 6233 3785) indicates wood space heating usage is dropping due to recent incentives and (slow) gas penetration, and there are no plans to restrict use.
- Gas generation (Bell Bay expansion, cogeneration) under BAU: moderate to significant increase, as no other alternative (see above).
- Housing construction standards: trends, 4-5 star. Tony Beaumont, Office of Energy indicated in September 2006 that there are no plans to introduce higher new housing standards.

2.3 Mild intervention scenario

Features

- Mild carbon signal, increasing from \$5/t CO_2 in 2010, to \$15/t CO_2 in 2020 to \$25/t CO_2 in 2040.
- Mild demand side management (DSM) policy acceleration compared with BAU.
- NIEIR projections for this scenario covering those elements outlined for the BAU above.

Scenario 2 details

1. **Carbon signals** do not increase hydro and other renewables sent out prices but do increase price of gas generation in Tasmania and of imports from Victoria by:
   - \$5/t CO_2 in 2010 to \$15/t CO_2 in 2020, linear increase by \$1/t CO_2 per year increasing price of imports (Victorian brown coal generation) by \$1.30/MWh per year (GHGI of average 1.3t CO_2/MWh); gas electricity prices by \$0.5/MWh (average intensity of 0.5t CO_2/MWh) per year and gas prices rise by, at \$1/t CO_2 per year, \$0.057/GJ per year;
   - \$15/t CO_2 in 2020 to \$25/t CO_2 in 2040, linear increase by \$0.5/t CO_2 per year, increasing price of imports (Victorian brown coal) by \$0.6/MWh per year (GHGI average of 1.2t CO_2/MWh); gas electricity prices increase by \$0.25/MWh (GHGI of 0.5t CO_2/MWh) per year and gas prices rise by, at \$0.5/t CO_2 per year, \$0.029/GJ per year.
2. **Air conditioners:** Air conditioner MEPS result in the efficiency of new units increasing by 15 per cent from 2008 to 2020 and by 25 per cent from 2020 to 2040.
3. **Peak pricing, load control.** Interval meters (IM) are available from 2020. Peak prices increase by 30 per cent from 2020 on.

   Customers are offered a lower peak price of 10 per cent above off-peak if they agree to direct load control: 30 per cent of customers accept this offer.
4. As in BAU assume **no** hydro expansion due to water constraints (although there may be efficiency improvements in existing hydro plants). Carbon prices stimulate more gas generation than in BAU as prices of imports from Victorian brown coal generation increases relative to gas generation prices.
5. Split system penetration similar to BAU scenario.
6. Tasmanian renewable energy target (TARET) of 5 per cent of total end-use in 2015 = 595 GWh, increasing at 5 per cent per year until 2025, remaining at that level to 2040. TARET commences in 2010. Only renewable generators commissioned after 2010 would be eligible to participate in TARET.

2.4 Stringent intervention scenario

Features

- Stringent carbon signal, increasing from \$10/t CO_2 in 2010, to \$25/t CO_2 in 2020 and \$50/t CO_2 in 2040.
- Stringent demand side management policy acceleration compared with BAU.
- Further restrictions on wood use.
- NIEIR projections for this scenario covering those elements outlined for BAU above.

Scenario 3 details

1. Carbon signals increase prices of gas generation in Tasmania and imports from Victoria by:

   - \$10/t CO_2 in 2010 to \$25/t CO_2 in 2020, linear increase by \$1.50/t CO_2 increasing price of imports (Victorian brown coal generation) by \$1.95/MWh/year (GHGI of 1.3t CO_2/MWh); gas electricity prices increase by \$0.65/MWh per year (average GHGI of 0.5t CO_2/MWh) and gas prices at \$1.50/t CO_2 per year, increase by \$0.086/GJ per year;

   - \$25/t CO_2 in 2020 to \$50/t CO_2 in 2040, linear increase by \$1.25/t CO_2 per year, increasing price of imports (Victorian brown coal) by \$1.5/MWh/year (GHGI of 1.2t CO_2/MWh); gas electricity prices increase by \$0.5/MWh per year (average GHGI of 0.4t CO_2/MWh) and gas prices at \$1.25/t CO_2 per year, increase by \$0.071/GJ per year.

2. **Air conditioners:** Air conditioner MEPS result in the efficiency of new units increasing from 2008-20 of 30 per cent and by 40 per cent from 2020-40.

3. **Peak pricing, load control.** Peak prices increase by 60 per cent from 2015 **or** when assumed interval meters are available.

   Customers are offered a lower peak price of 25 per cent above off-peak price if they agree to direct load control: 50 per cent of customers accept this offer.

4. Gas heating (space, water) and split system penetrations increase.

5. Gas fired generation increases slower than the BAU as TARET is increased.

6. Higher renewables target than scenario 2 in Tasmania (TARET) of 10 per cent of total end-use in 2015 = 1,189 GWh, growing at 5 per cent per year to 2025 and remaining at that level to 2040.

Same eligibility rules and commencement as TARET in scenario 2.

Other comments

In scenarios 2 and 3, the Tasmanian economy, because of its renewable resources, fares better than the other States that have a much greater reliance on fossil fuels, and this tends to increase Tasmania's economic growth rate.

3. Projections of Tasmanian electricity energy and demands to 2040

3.1 Introduction

This section tabulates projections of Tasmanian energy and peak demands to 2040 for each of the three scenarios outlined in Section 2 of this report.

3.2 Tasmanian energy projections to 2040

Table 3.1 presents forecasts of total electricity generated by scenario to 2040.

Under the BAU scenario, energy growth over the 35 year period averages 1.3 per cent per annum. This represents total volume growth of nearly 6,000 GWh, or absolute percentage of around 60 per cent.

It is important to note that the BAU, mild and stringent scenarios do not factor any downside risks to Tasmania's industrial sector. The loss of one or more of Tasmania's top five industrial customers over the next three decades would lead to a significant fall in generation.

Figure 3.1 shows Tasmanian electricity generated and projected generation in 2040 for the BAU, mild and stringent scenarios.

Under the mild scenario, total electricity generated rises by 1.1 per cent per annum between 2005 and 2040, 0.2 percentage points below the BAU scenario. In volume terms, energy generated by 2040 is some 0.7 terawatt hours lower than the BAU scenario.

Under the stringent scenario, average growth in electrical energy generated is 0.9 per cent per annum between 2005 and 2040. Compared to the BAU scenario, total electrical energy generated by 2040 under the stringent scenario is nearly 2 terawatt hours lower than the BAU scenario.

Higher renewable energy targets under the stringent scenario and stronger carbon signals generate higher electricity and gas prices. More stringent MEPs for gas heating appliances and air conditioners lowers average energy usage by the residential and commercial sector.

Figure 3.2 shows an index of electricity intensity per $ million of Tasmanian gross state product by scenario. By 2040, compared with 2005, the electricity intensity of the Tasmanian economy:

1. falls by 15 per cent between 2005 and 2040 under the BAU scenario;
2. falls by 19 per cent between 2005 and 2040 under the mild scenario; and
3. falls by 24 per cent between 2005 and 2040 under the stringent scenario.

Table 3.1 Tasmanian electricity generated by scenario – generated (GWh)

	BAU	Mild	Stringent
2005	10674.7	10674.7	10674.7
2010	11689.4	11689.4	11689.4
2015	12487.2	12366.2	12287.8
2020	13117.0	12886.0	12592.6
2025	13861.8	13498.8	13004.3
2030	14870.8	14383.8	13680.4
2035	15840.8	15234.8	14326.3
2040	16602.6	15877.6	14767.2
Average percentage growth			
2005-2010	1.8	1.8	1.8
2010-2015	1.3	1.1	1.0
2015-2020	1.0	0.8	0.5
2020-2025	1.1	0.9	0.6
2025-2030	1.4	1.3	1.0
2030-2035	1.3	1.2	0.9
2035-2040	0.9	0.8	0.6
2005-2040	1.3	1.1	0.9
Absolute growth			
2010-2020	1427.6	1196.6	903.2
2020-2030	1753.8	1497.8	1087.8
2030-2040	1731.8	1493.8	1086.8
2005-2040	5928.0	5203.0	4092.5

Figure 3.1: Electricity generated, Tasmania 2005 and 2040

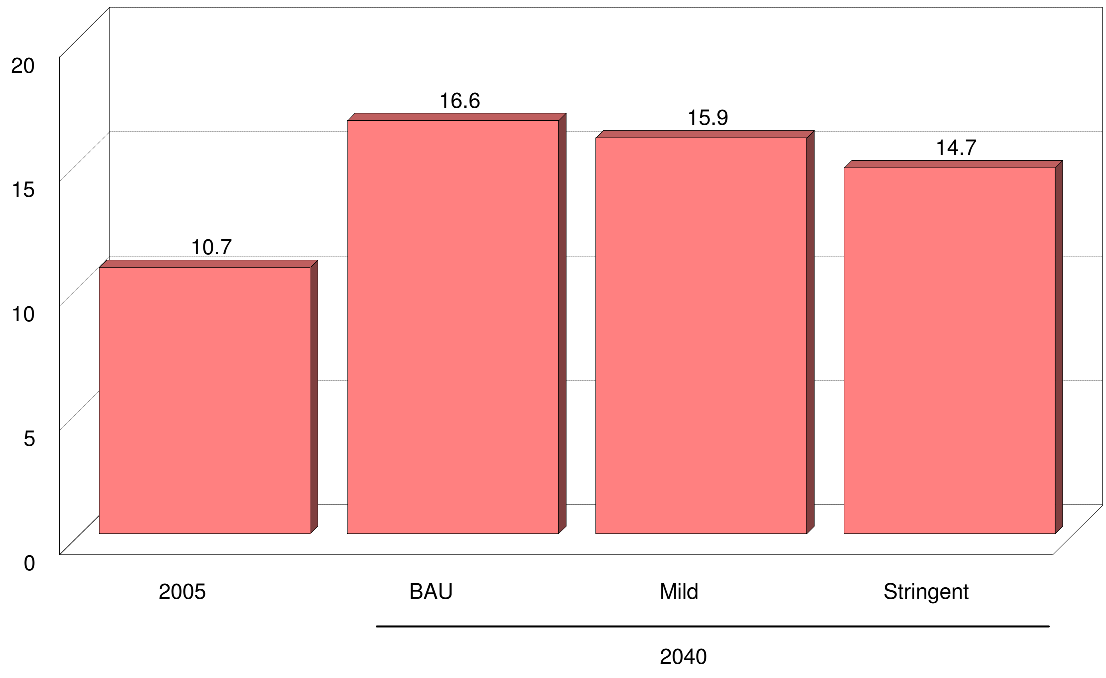
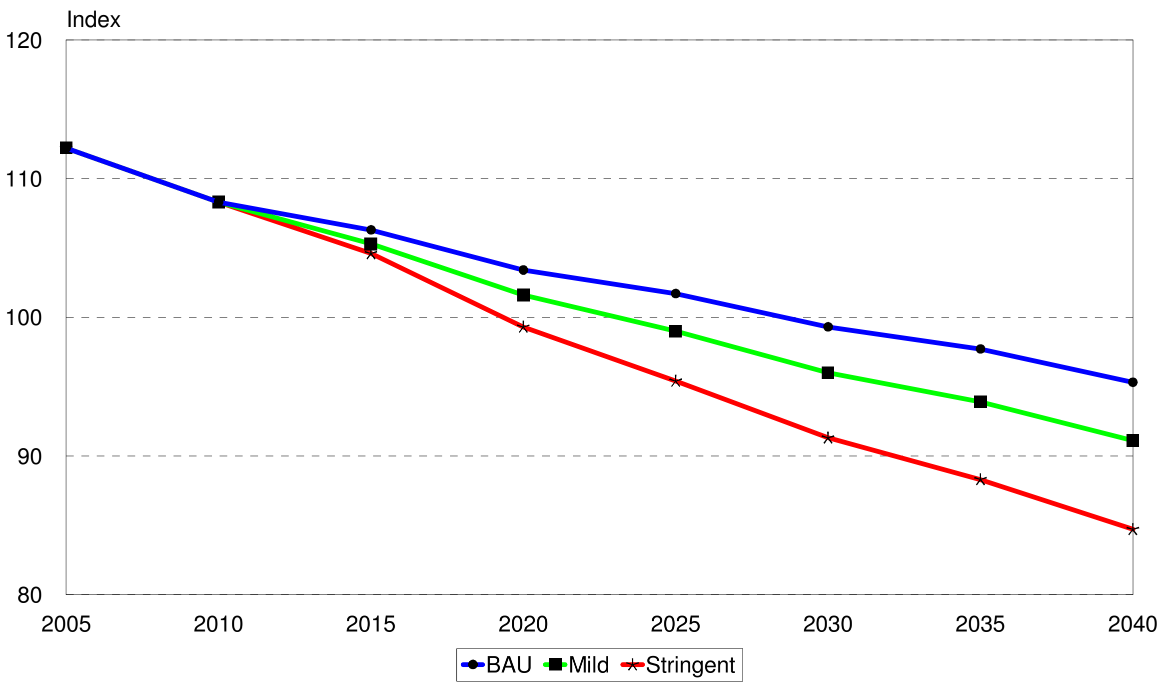


Figure 3.2: Electricity intensity of the Tasmanian economy by scenario



3.3 Maximum demand projections to 2040 by scenario

Tables 3.2 to 3.4 present forecasts of the winter maximum demand to 2040 by scenario. Figure 3.3 shows the 2005 Tasmanian winter maximum demand (MD) and the projections for 2040 for each of the three scenarios.

Under the BAU scenario, growth in winter demands is around 1.5 per cent per annum over the 2005 to 2040 period. Absolute growth in the 50th percentile MD under the BAU scenario is around 1,200 MW. This outcome suggests Tasmania may require some peaking plant post 2020, in addition to intermediate and base load gas fired generation.

Under the mild scenario, growth in the winter MD is reduced to around 1.1 per cent per annum over the period to 2040. Absolute growth is around 870 MW for the 10th percentile winter MD.

Under the stringent scenario, growth in the winter MD is reduced to 0.9 per cent per annum. Absolute growth over the period is around 650 MW.

There are significant efficiency gains in reverse cycle air conditioners, peak pricing and direct load control in both the mild and stringent scenarios to 2040.

Figure 3.3: Maximum winter 10th percentile demands 2005 and 2040 - BAU, mild and stringent scenarios

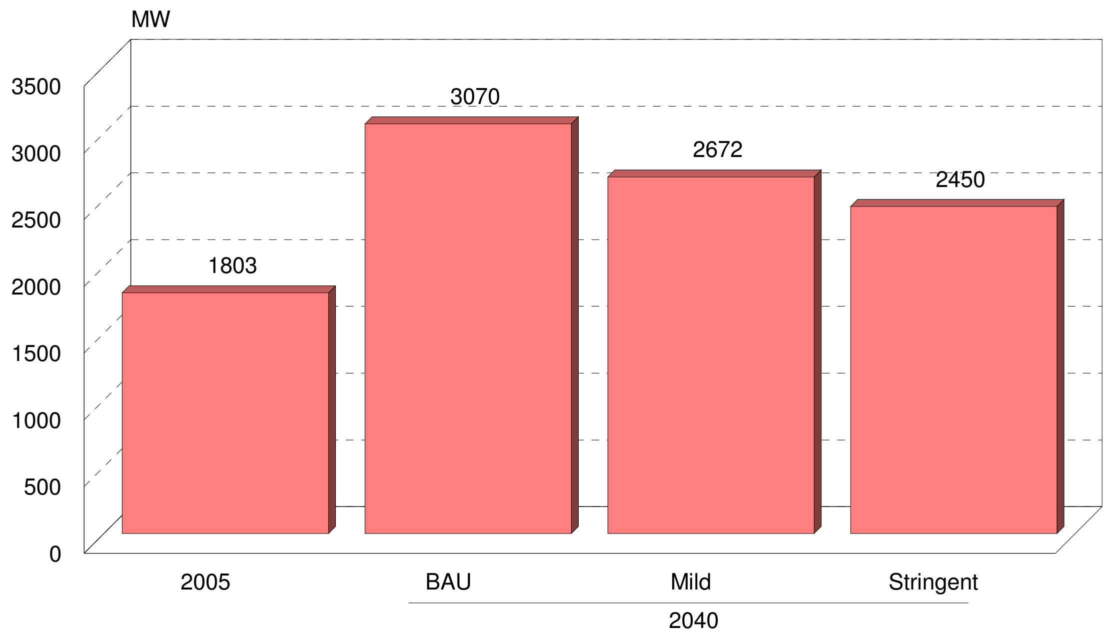


Table 3.2 Maximum demands (including embedded generation) – BAU scenario (MW)

	Winter			Summer		
	10th	50th	90th	10th	50th	90th
2005	1802.6	1802.6	1802.6	1366.6	1366.6	1366.6
2010	2022.8	2002.4	1943.8	1579.2	1559.1	1542.2
2015	2189.9	2167.8	2094.0	1698.9	1676.5	1657.6
2020	2336.0	2312.4	2221.6	1800.1	1775.6	1755.1
2025	2491.8	2454.5	2369.8	1901.3	1875.4	1853.8
2030	2684.4	2644.2	2553.0	2028.1	2000.5	1977.4
2035	2877.6	2834.6	2736.7	2152.8	2123.5	2099.0
2040	3069.6	3023.7	2919.3	2273.8	2242.9	2217.0
Average percentage growth						
2005-2010	2.3	2.1	1.5	2.9	2.7	2.4
2010-2015	1.6	1.6	1.5	1.5	1.5	1.5
2015-2020	1.3	1.3	1.2	1.2	1.2	1.1
2020-2025	1.3	1.2	1.3	1.1	1.1	1.1
2025-2030	1.5	1.5	1.5	1.3	1.3	1.3
2030-2035	1.4	1.4	1.4	1.2	1.2	1.2
2035-2040	1.3	1.3	1.3	1.1	1.1	1.1
2005-2040	1.5	1.5	1.4	1.5	1.4	1.4
Absolute growth						
2010-2020	313.2	310.0	277.8	220.9	216.5	212.9
2020-2030	348.4	331.8	331.4	228.0	224.9	222.3
2030-2040	385.2	379.5	366.4	245.7	242.3	239.5
2005-2040	1267.0	1221.1	1116.7	907.2	876.3	850.4

Table 3.3 Maximum demands (including embedded generation) – Mild scenario (MW)

	Winter			Summer		
	10th	50th	90th	10th	50th	90th
2005	1802.6	1802.6	1802.6	1366.6	1366.6	1366.6
2010	2022.8	2002.4	1943.8	1579.2	1559.1	1542.2
2015	2130.9	2105.9	2034.3	1671.7	1646.9	1626.1
2020	2212.7	2186.7	2110.5	1734.1	1708.2	1686.5
2025	2309.4	2282.3	2200.7	1807.9	1780.8	1758.1
2030	2444.7	2414.0	2329.5	1910.7	1882.0	1858.0
2035	2573.2	2540.8	2451.7	2007.8	1977.6	1952.4
2040	2671.9	2638.2	2545.7	2081.3	2050.0	2023.7
Average percentage growth						
2005-2010	2.3	2.1	1.5	2.9	2.7	2.4
2010-2015	1.0	1.0	0.9	1.1	1.1	1.1
2015-2020	0.8	0.8	0.7	0.7	0.7	0.7
2020-2025	0.9	0.9	0.8	0.8	0.8	0.8
2025-2030	1.1	1.1	1.1	1.1	1.1	1.1
2030-2035	1.0	1.0	1.0	1.0	1.0	1.0
2035-2040	0.8	0.8	0.8	0.7	0.7	0.7
2005-2040	1.1	1.1	1.0	1.2	1.2	1.1
Absolute growth						
2010-2020	189.9	184.3	166.7	154.9	149.1	144.3
2020-2030	232.0	227.3	218.9	176.6	173.8	171.5
2030-2040	227.2	224.2	216.2	170.6	167.9	165.7
2005-2040	869.3	835.6	743.1	714.7	683.4	657.1

Table 3.4 Maximum demands (including embedded generation) – Stringent scenario (MW)

	Winter			Summer		
	10th	50th	90th	10th	50th	90th
2005	1802.6	1802.6	1802.6	1366.6	1366.6	1366.6
2010	2022.8	2002.4	1943.8	1579.2	1559.1	1542.2
2015	2108.0	2083.7	2013.9	1652.9	1628.8	1608.5
2020	2152.1	2127.2	2054.4	1685.9	1661.1	1640.4
2025	2211.1	2185.5	2108.8	1730.4	1704.8	1683.4
2030	2303.0	2274.6	2196.2	1799.6	1773.0	1750.8
2035	2389.3	2359.8	2278.5	1864.4	1836.8	1813.6
2040	2449.7	2419.4	2335.9	1908.5	1880.3	1856.6
Average percentage growth						
2005-2010	2.3	2.1	1.5	2.9	2.7	2.4
2010-2015	0.8	0.8	0.7	0.9	0.9	0.8
2015-2020	0.4	0.4	0.4	0.4	0.4	0.4
2020-2025	0.5	0.5	0.5	0.5	0.5	0.5
2025-2030	0.8	0.8	0.8	0.8	0.8	0.8
2030-2035	0.7	0.7	0.7	0.7	0.7	0.7
2035-2040	0.5	0.5	0.5	0.5	0.5	0.5
2005-2040	0.9	0.8	0.7	1.0	0.9	0.9
Absolute growth						
2010-2020	129.3	124.8	110.6	106.7	102.0	98.2
2020-2030	150.8	147.3	141.9	113.8	111.9	110.4
2030-2040	146.8	144.9	139.7	108.9	107.2	105.8
2005-2040	647.1	616.8	533.3	541.9	513.7	490.0

4. Natural gas usage in Tasmania to 2040

4.1 Introduction

This section presents projections of natural gas usage for Tasmania to 2040 for each of the three energy scenarios modelled, the BAU, mild and stringent scenarios.

These scenarios for natural gas usage assume that the capacities of the Basslink interconnector is not increased over the period to 2040.

4.2 Scenario results

Table 4.1 shows projections of natural gas usage to 2040 by scenario. Under the BAU scenario, natural gas usage in Tasmania rises by 4.4 per cent per annum between 2005 and 2040. Total volume growth over the period is nearly 50 petajoules over the period to 2040.

As current capacity of the Tasmanian gas pipeline is 47 petajoules per annum, duplication and/or augmentation of the pipeline is required under the BAU scenario by 2030. Figure 4.1 shows total gas usage by scenario for 2005 and 2040. Figure 4.2 shows electricity generation natural gas usage by scenario for 2005 and 2040.

Under the mild scenario, total natural gas usage rises by 40 petajoules between 2005 and 2040. Growth is more subdued due to the TARET (renewable electricity) measure between 2015 and 2025. Natural gas usage in electricity generation rises by only 3 petajoules between 2010 and 2020, but by nearly 10 petajoules between 2020 and 2030 and 2030 and 2040. A pipeline expansion is still required under the mild scenario by around 2035.

Under the stringent scenario, natural gas usage in Tasmania rises by 25 petajoules between 2005 and 2040. Expanded TARET measures under the stringent scenario reduce gas usage in electricity generation relative to the BAU scenario. Actual gas usage in electricity generation falls between 2010 and 2020 and then rises post 2020, but at a lower rate than the BAU and mild scenarios. A natural gas pipeline expansion is not required by 2040 under the stringent scenario.

Figure 4.1: Total natural gas usage - Tasmania 2005 and 2040 - BAU, mild and stringent scenarios

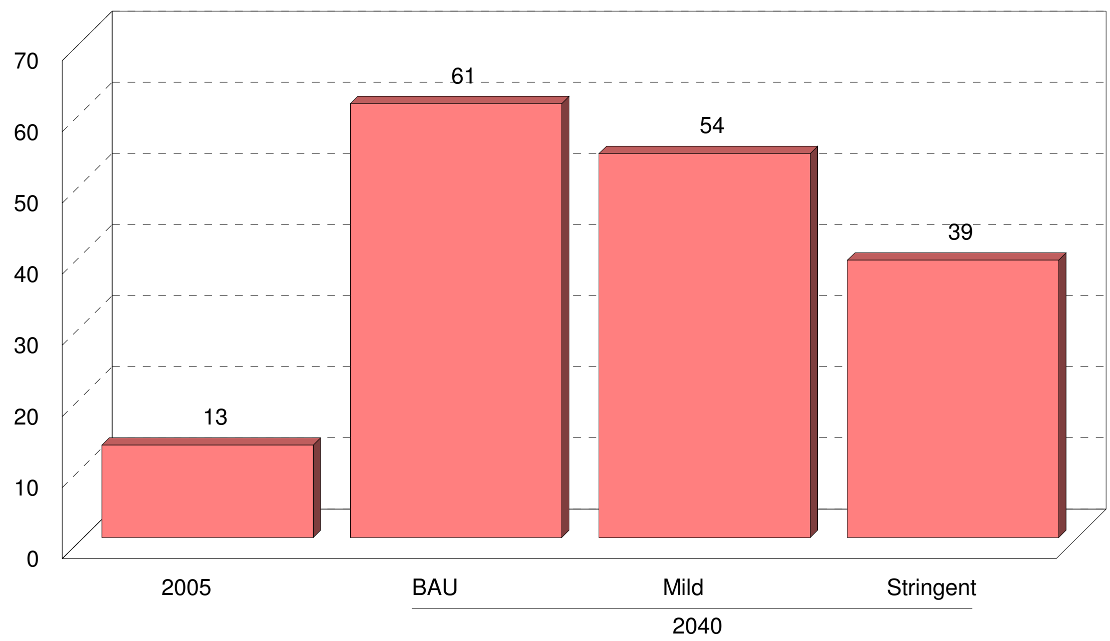


Figure 4.2: Total natural gas usage in electricity generation 2005 and 2040 - BAU, mild and stringent scenarios

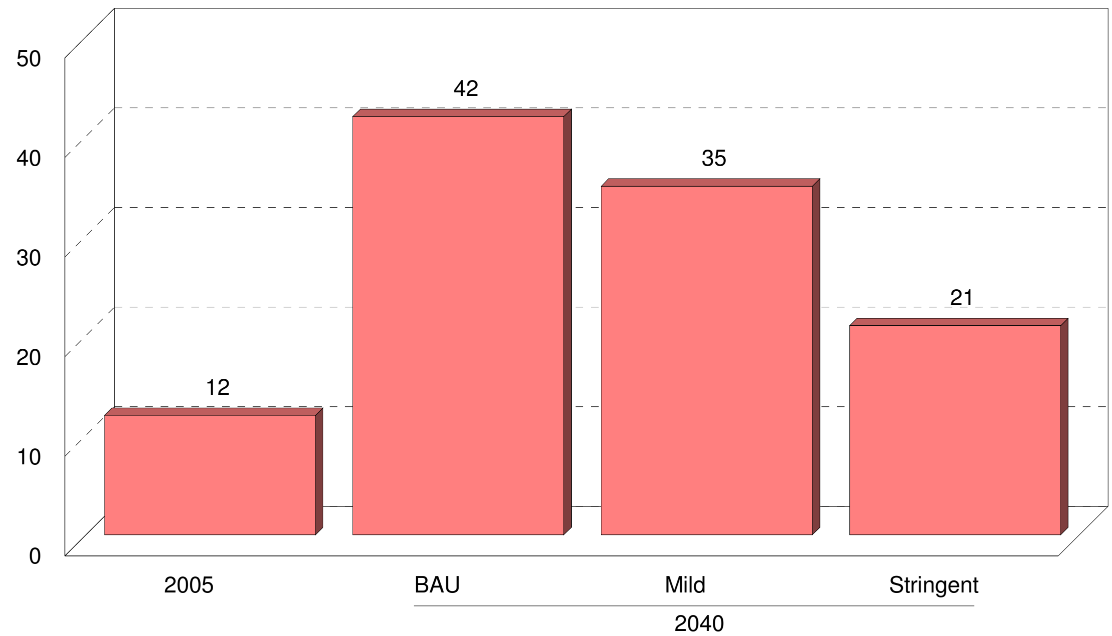


Table 4.1 Total natural gas usage to 2040 – BAU, mild and stringent scenarios (petajoules)

	BAU	Mild	Stringent
2005	13.4	13.4	13.4
2010	19.0	19.0	19.0
2015	25.3	24.1	19.0
2020	31.7	28.4	20.5
2025	38.0	32.9	22.2
2030	46.5	40.7	28.3
2035	54.5	48.1	34.1
2040	61.0	54.1	38.5
Average percentage growth			
2005-2010	7.3	7.3	7.2
2010-2015	5.9	4.9	0.0
2015-2020	4.6	3.3	1.6
2020-2025	3.7	3.0	1.6
2025-2030	4.1	4.3	5.0
2030-2035	3.2	3.4	3.8
2035-2040	2.3	2.4	2.5
2005-2040	4.4	4.1	3.1
Absolute growth			
2010-2020	12.6	9.3	1.5
2020-2030	14.8	12.3	7.8
2030-2040	14.5	13.4	10.2
2005-2040	47.6	40.7	25.1

Table 4.2 Natural gas usage in electricity generation to 2040 – BAU, mild and stringent scenarios (petajoules)

	BAU	Mild	Stringent
2005	11.5	11.5	11.5
2010	12.7	12.7	12.7
2015	13.5	13.2	8.6
2020	17.9	15.7	8.6
2025	23.0	18.9	9.0
2030	30.0	24.9	13.7
2035	36.6	30.8	18.1
2040	41.9	35.2	21.1
Average percentage growth			
2005-2010	2.0	2.0	2.0
2010-2015	1.3	0.7	-7.5
2015-2020	5.7	3.6	0.1
2020-2025	5.2	3.7	1.0
2025-2030	5.5	5.7	8.6
2030-2035	4.1	4.3	5.8
2035-2040	2.7	2.7	3.1
2005-2040	3.8	3.2	1.8
Absolute growth			
2010-2020	5.2	3.0	-4.1
2020-2030	12.1	9.2	5.1
2030-2040	11.9	10.2	7.4
2005-2040	30.4	23.7	9.6

Appendix 2 High level scenarios developed for the vision

The factors included for each scenario used in the vision development are described below.

Scenario 1: 'Growth'

In this scenario, a range of factors lead to much greater demand growth than is currently foreseen:

The following influencing factors lead to . . .	. . . these consequences
• Climate change increases temperatures • Clean green image of Tasmania is further strengthened • Tasmania's population grows dramatically – partially driven by a wave of wealthy, lifestyle oriented retirees - and air conditioning penetration reaches a high level • Tasmanian economy booms – several major industrial loads are added • Many young professionals move from electricity to other competing industries • Electricity supply quality and reliability expectations increase dramatically • Hardening community attitudes towards environmental impact (lines and stations) • Multiple changes in the regulatory environment creates more uncertainty for investment • Transend and Aurora Distribution are each sold to different national infrastructure owners	Demand significantly exceeds the NIEIR forecasts, and equals 4500MW: • East Coast: 800MW • NW industry: 1000MW • Hobart and Tamar: 2400MW • West Coast: 300MW Social, demographic and economic changes: • East Coast tourist / sea change developments • New mineral extraction and processing projects (West & North West) • New industrial loads in North West • Transmission line easements extremely difficult to obtain or expand • High temperatures and air conditioning penetration drive a move to summer peaks, and peakier load profile • Significant gas power generation built close to population centres and industrial loads near Hobart, Launceston and in the North West • A number of legal actions have been instituted over reliability Supply profile (approximate) – 4700MW • Basslink: 500MW • Hydro: 2500MW • Wind: 300MW • Gas (CCGT): 1400MW (North: 900MW, North-West: 200MW, South: 300MW) • Losses=200MW • Installed reserve=800MW

Scenario 2: 'Export'

In this scenario, a range of factors lead to much of the Tasmanian electricity industry being directed towards export of 'green' peaking power to the mainland NEM regions via increased Bass Strait transfer capacity:

The following influencing factors lead to . . .	. . . these consequences
• Climate change increases temperatures. Tasmanian storage inflows are only marginally affected, but Snowy and Victorian hydro inflows are reduced • High carbon price introduced, leading to high NEM prices (100% increase) • Energy intensive industries move out of Australia (and Tasmania) • Scale economies in wind technology reduce wind costs to $50 per MWh • Increasing network performance standards are imposed • Economic growth is low to moderate. However, dispersed agricultural industry demand growth is high • Community opposition to sale of public assets: Transend stays in Government ownership • Regulation is adjusted to favour investment in strong inter-regional links	• Demand is equivalent to NIEIR 'Stringent carbon' scenario, ie 2450MW • 800MW of extra wind power is installed (assumed 640MW or 80% of nameplate rating at time of maximum export demand): 240MW in North-West, 200MW in North-East, 160MW Heemskirk, 200MW in central plateau • Hydro installs an additional 260MW capacity on major storages to maximise its peaking capacity: New generator at Gordon (145MW), plus ~5% increase on the 2100MW in all other hydro generator capacities through refurbishment with high hydraulic efficiency runners and guide vanes (except Trevalyn which has already been refurbished) • Basslink exports at full capacity for much of the time and the link becomes a NEM regulated asset • Cross-Bass Strait export capacity is increased to 1500MW (different capacities and location of cable(s) to be modelled)[25] • Further 200MW combined cycle gas turbine installed in the South (Bridgewater) • Loss of 300MW of major industrial load, mainly in the South – for example, possible reductions may include loads such as: Zinifex (125MW), Norske Skog (80MW), Temco (95MW) • Tasmanian Government stringently rations Transend's access to capital

[25] Rather than choose a capacity that is a multiple of current Basslink capacity, 1500MW provides the opportunity for Transend to explore new issues arising from a second cable that is much larger than the existing one.

Scenario 3: 'Import'

In this scenario, a range of factors lead to Tasmania relying on electricity imports from the mainland via increased Bass Strait transfer capacity:

The following influencing factors lead to . . .	. . . these consequences
• Climate change reduces rainfall and shifts it across the State to the East, leaving Hydro short of water • Wind power investment is not subsidised and wind energy remains relatively high cost • Depletion of Bass Strait gas reserves sees high increase in gas price • Low cost carbon capture technology limits carbon price to a low level • Low NEM wholesale electricity price • Overall demand growth is steady and industrial loads are sustained	• Demand is equivalent to NIEIR 'Business as usual' scenario, ie 3000MW • Basslink imports at full capacity for much of the time and the link becomes a NEM regulated asset • Cross-Bass Strait import capacity is increased to 1500MW (different capacities and location of cable(s) to be modelled)[26] • Hydro capacity is 1100MW due to very dry conditions and low inflows: West: 600MW, Mersey Forth 300 MW, Gordon 200 MW • Hydro moves to more of a peaking supplier, with reliance on coal and gas from Victoria for base load supply • Gas capacity is 320MW: CCGT (200MW), OCGT (120MW) • Wind capacity is 140MW installed (assumed 110MW or 70% of nameplate rating at time of maximum demand) • Limited incentives for local generation investment: No new wind farms built, no new gas power generation • 200MW of interruptible load is provided by Comalco

Scenario 4: 'Business as usual'

In this scenario, Tasmania's current situation continues with only slow incremental growth in demand and no significant discontinuities in the operating circumstances of the network business:

The following influencing factors lead to . . .	. . . these consequences
• No carbon price is introduced • Several major industrial loads leave the State over the period • Tasmanian economy is relatively static	• Demand on the transmission system is generally weak - transmission network investment is mainly to address ageing assets and some slow demand growth • Basslink is used primarily as export in peak periods, but without carbon price signal, it is under-utilised

Note: This scenario is included for completeness only. The impact of this scenario on the transmission system, and therefore Transend, is largely to reduce the role of the business to one of maintenance only, with little significant 'step change' investment required.

[26] Rather than choose a capacity that is a multiple of current Basslink capacity, 1500MW provides the opportunity for Transend to explore new issues arising from a second cable that is much larger than the existing one.

Appendix 3 Resources used on this project

a. Stakeholders consulted

Through the course of this project, The Nous Group consulted extensively with stakeholders within and outside Transend. These interactions took place primarily through the following vehicles:

1. Individual interviews were conducted between October 2006 and January 2007:

Transend	Other stakeholders	
Richard Bevan	Andrew Reeves (OTTER)	Richard Sulikowski (DTF)
Paul Oxley	Phil Harrington (DIER)	Paul Bloomfield (Aurora Retail)
Stephen Clark	Vince Hawksworth (Hydro)	John Devereux (Aurora Dist)
Michael Hunnibell	Mark Kelleher (Roaring 40s)	Ben Skinner (TRU Energy)
Peter Clark	Simon Himson (Alinta)	Matt Zema (VENCorp)
Mike Green	Stephen Orr (International Power)	Richard Sulikowski (DTF)
Pradip Verma	Damon Thomas (TCCI)	Paul Bloomfield (Aurora Retail)
Wayne Tucker	Norm McIlfatrick (Economic Devt)	David Gaskell (Zinifex)
	Jenny Jarvis (Rio Tinto)	Jason Franklin (Rio Tinto)

Table 11: Stakeholder interviews

2. Two half-day interactive, scenario planning workshops were held in November 2006:

Workshop 1 attendees	
Richard Bevan	Peter Clark
Stephen Clark	Wayne Tucker
Michael Hunnibell	Pradip Verma
Chandra Kumble	Soruby Bharathy

Table 12: Workshop 1 (internal stakeholders) attendees

Transend	Others	Organisation
Richard Bevan	Glen Poynter	Zinifex
Stephen Clark	Paul Bloomfield	Aurora Retail
Michael Hunnibell	Andrew Roberts	Aurora Network
Paul Oxley	Andrew Catchpole	Hydro Tasmania
Peter Clark	Mark Kelleher	Roaring 40s
Michael Green	Andrew Reeves	Office of the Tasmanian Energy Regulator
Pradip Verma	Phil Harrington	Department of Infrastructure, Energy & Resources
Wayne Tucker	Matt McGee	Department of Economic Development
Sead Pasalic		
Chandra Kumble		
Soruby Bharathy		

Table 13: Workshop 2 (internal and external stakeholders) attendees

3. Four business response workshops were held in February, each focusing on a different potential response area for Transend:

	Workshop 1: Internal planning	Workshop 2: Stakeholder engagement in planning	Workshop 3: Transend's industry leadership role	Workshop 4: Technical capability
Attendees	• Sead Pasalic • Michael Seddon • Tim May • Soruby Bharathy • Dinesh Perera • Selina Lyons • Chandra Kumble	• Sead Pasalic • Michael Seddon • Tim May • Soruby Bharathy • Dinesh Perera • David Allen • Chandra Kumble	• Richard Bevan • Paul Oxley • Roger Riley • Matthew Hosan • Michael Hunnibell • Stephen Clark • Elizabeth De Lacy • Bess Clark • Leigh Burrill	• Bruce Longmore • Prahlad Tilwalli • Graham Shepherd • Chandra Kumble • Soruby Bharathy

Table 14: Business response workshops

b. Documents reviewed

The following are the major documents that have been reviewed in the course of this project:

- Transend 2005/06 Annual Report
- Transend 2006 Annual Planning Report
- NIEIR, 'Energy scenarios for Tasmania to 2040', October 2006 (report commissioned by Transend).
- Prime Minister & Cabinet, 'Uranium Mining, Processing and Nuclear Energy Review', Draft Report, November 2006.
- Allen Consulting Group – The Greenhouse Challenge for Energy, September 2004

- Cooperative Research Centre for Coal in Sustainable Development, 'Options for Electricity Generation in Australia', Technology Assessment Report 44, January 2005
- Papers from AIE National Conference, November 2006 – DITR
- Published reports on climate change and the economic effects of policy options (e.g. by CSIRO, IPCC)
- Government reports on climate change and policy options (e.g. government Greenhouse Office papers and risk scenario reports)
- Research commissioned by industry bodies such as the National Generators Forum and the CRC for Clean Coal and Sustainable Development.

Reference was also made to information on the following websites:

- Australian Bureau of Statistics (www.abs.gov.au)
- NEMMCO (www.nemmco.com.au)

c. Network studies

As a result of the work done to generate scenarios in developing the vision, Transend undertook some system studies to examine the effect of the scenarios on the network. These studies tested energy and peak load requirements in different regions and on different parts of the network, for each of the agreed scenarios. Points of constraint were identified, as well as more general issues for the development of the network.

From this work, some preliminary options for addressing these potential network development issues were identified. The results of this work are discussed in Section G above.

For further detail on this work, and the latest system study documentation, please see Dr Chandra Kumble in the 'Connections and Strategic Development Group' at Transend.

d. Technology research

To inform the responses that may be open to Transend in positioning itself to meet possible scenarios over the next 30+ years, Transend staff with expertise in specific areas of technology were asked to conduct research into current and likely future developments in their areas.

As well as contributing to and informing the vision, the work was seen to have important benefits for staff capability, extending long term thinking about technology, and how it can contribute to organisational strategy. The areas that Nous believes merit developing a sound knowledge base are set out in Table 15 below.

Paper
Network development and transmission lines Mini HVDC lines and converter stations High temperature line conductors (already in use in Transend) Low EMF designs to cut easement widths
Primary systems FACTS[27] solutions using improved (possibly diamond) thyristor units Superconducting current limiting links 'Soft' (point on wave) switching Gas insulated bus work Dry (oil free) bushings Single break switching Embedded digital transducers Ultra low maintenance technology Graded action switching based on real time modelling
Secondary systems Pervasive digital technology Comprehensive standards (e.g. IEC61850) providing 'plug and play' design flexibility New LAN and WAN solutions
Intelligent networks Distributed control systems Self-learning intelligent systems Packet switched networks (TCP/IP) Wireless networks (site and wide area) Satellite links
Construction, operation and maintenance Off-site modular construction and repair Relocatable collections of plant (bay in a container) Fast swap sealed units Zero scheduled maintenance plant
Network configuration and stability Distributed terminal stations (terminal station spread across multiple sites) Single switched lines (as maintenance outages reduce to near zero) Dynamic plant ratings based on real time measurement and modelling (already used by Transend) Dynamic superconducting energy storage for faults Static controlled Var compensators and braking resistors

Table 15: Technology research papers

Papers that have been produced to date cover the following areas:

- Interoperability (IEC61850)
- Mini HVDC and converters
- Secondary systems
- Transmission lines.

Nous would recommend that further research be conducted, but as part of a coherent technology strategy.

[27] Flexible AC Transmission Systems based on high voltage power electronic switching.

Appendix 4 Project approach and methodology

This Appendix sets out the project methodology, followed by an explanation of the analysis framework used.

a. Methodology

Phase 1:

1. Confirm scope, plan, issues and key stakeholders.

Phase 2:

2. Review relevant research and background materials, and initiate technical investigations by Transend's technology experts
3. Conduct a series of interviews with key stakeholders, both internal and external to Transend, and develop draft influencing factors and long term scenarios
4. Facilitate workshops with the Transend management team and key external stakeholders to refine and validate thinking on major influencing factors and scenarios
5. Initiate a set of system studies that follow from the scenarios.

Phase 3:

6. Through short workshop discussions, develop the key business responses to the range of scenarios that are likely to constitute major focus areas for Transend's transmission business over the next 30+ years
7. Develop recommendations (short, medium and long term) to enable Transend to optimise its position as potential scenarios unfold
8. Draft and present the final project report.

Phase 4:

9. Incorporate any final feedback from Transend management into the vision document and deliver it to conclude the project.

Phases 1 and 2

Phase 1 consisted of consultations with the Transend project team (Stephen Clark, Chandra Kumble, Soruby Bharathy) to confirm the scope of the work and the project plan.

The project proper commenced in Phase 2 with a series of interviews with key internal and external stakeholders, as listed in Appendix 3. Together with Nous' own research, these discussions helped establish the context for the Tasmanian transmission network and identify a series of key factors likely to influence the network over the next 30+ years.

In parallel, Transend's technical experts commenced research into a number of technology areas likely to be relevant to the business responses required of Transend. The research topics and format are set out in Appendix 3.

Following the stakeholder interviews, the Nous team generated four contrasting scenarios which included selected influencing factors. The scenario development process is described in more detail below, and the resulting scenarios are set out in Appendix 2.

On 22 November 2006, a workshop was held with most of the Transend senior management team. Participants tested the scenarios and suggested refinements and additions to the influencing factors. They also considered some of the potential consequences for the network, and possible impacts on Transend.

A second workshop was held on 30 November 2006, attended by a mix of Transend senior managers and key external stakeholders (including representatives of generators, retailers, distribution businesses, major customers, government and regulatory authorities). This group suggested further refinements to the scenarios and delved in more depth into their possible and likely implications. Participants also provided different stakeholder perspectives on their expectations of Transend's capabilities to respond to the different scenarios.

A list of attendees at these workshops is set out in Appendix 3 above.

Methodology – Phases 3 and 4

In Phase 3, the Nous team worked with Transend staff to analyse the results of network studies undertaken by Transend. These studies highlighted the likely requirements for each part of the network under the various scenarios, and hence the potential constraints that might emerge as events unfold. Following these findings, the Transend team conducted some preliminary investigations into possible solutions to these constraints, and their relative merits.

In parallel, the project team convened four workshops to drill down into the most critical business responses that emerged from the scenarios and their impact on network requirements. The thinking in those workshops formed the basis of recommendations as to actions that Transend should consider to strengthen its own capabilities.

From these two pieces of work a presentation was developed for the Board, and this final project report written.

b. Analysis framework

This section provides a high level outline of the analysis framework and methodology used in the project.

Overview: The scenario planning approach

The basic analysis framework used is shown in Figure 17. Because 30 years is too long a period to be approached with deterministic planning techniques, a scenario based approach has been used.

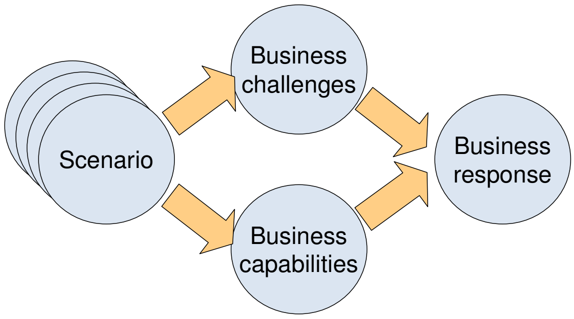


Figure 17: Analysis framework

Scenarios can be used to define the challenges to the electricity transmission business and assess the capabilities of the business to respond to them. Each scenario outlines a set of external and internal factors that constitute constraints, opportunities and threats to the electricity transmission business. Whilst each scenario must be reasonably credible, accuracy is of less importance than the power of the scenarios to reveal the challenges that may exist in 30 years time and define the capabilities required to meet them.

The typical internal and external factors encompassed by a scenario are shown in Table 16.

External factors	Internal factors
Regulatory strategy	Business strategy
Energy industry developments	Employee skills
Community attitudes	Workplace culture
Economic and demographic development	Capital availability
Environmental changes	

Table 16: Typical elements of scenarios

Aims

The development of scenarios in this project has been designed to extend Transend's thinking about what the transmission environment might look like in 30+ years. By grouping potential influencing factors together to vividly create a possible transmission world, the scenarios provide 'colour', and help the organisation to imagine a range of possible futures and hence, how it might need to respond.

In particular, scenarios need to 'push' management and technical thinking by creating situations that place challenging demands on the business. Scenarios are not predictions of what will happen, or even what is likely to happen – at least, not in that exact form. Instead, the scenarios should 'explore the boundaries of reasonable credibility'. By using three very different scenarios, we can see a broad range of those boundaries.

The business responses that Transend develops to meet future challenges will take account of the spectrum of possible network developments that fall within the boundaries broadly defined by the scenarios.

Approach

The Nous team constructed three initial scenarios drawn from targeted research and insights from a series of internal and external stakeholder interviews. For each scenario, a number of influencing factors were combined to form key characteristics of a particular ‘transmission world’. In some cases, possible consequences of factors were extrapolated to 30 years hence.

Three assumptions were made in constructing the scenarios:

1. Each scenario should contain ‘internal tensions’ between environmental, demand, supply, community and ownership factors
2. The influencing factors with most impact on the 30 year scenarios will be environmental, demand and supply factors
3. Technology developments will have their most relevance in thinking about the possible business responses open to Transend, rather than shaping the scenarios themselves.

In each scenario, the active influencing factors have been selected to create a reasonably credible overall picture, but also to apply conflicting pressures on Transend’s network business.

These scenarios were then tested with a group of key internal stakeholders in a workshop. Workshop participants contributed suggestions to refine the scenarios and incorporate additional active influencing factors. Working together, they also generated insights into some of the consequential challenges for the transmission network.

One week later, the refined versions of the scenarios were presented to a larger mixed group of internal and external stakeholders, who offered further refinements to improve the scenarios and defined a range of stakeholder expectations of Transend. The finalised scenarios are presented in Appendix 2 above.

Development of business responses

Knowing the potential challenges and the required capabilities, the likely form of business response can be determined. For a given challenge, each capability has a comparative value which either makes it preferred or non-preferred. When a range of business capabilities have been selected for application, their deployment must be internally self-consistent so they form a coherent response in which value is preserved and maximised.

The development of business responses is valuable in that it can reveal gaps in business capability that warrant early action. The development of business responses to meet the challenges thrown up by scenarios is illustrated in Figure 18.

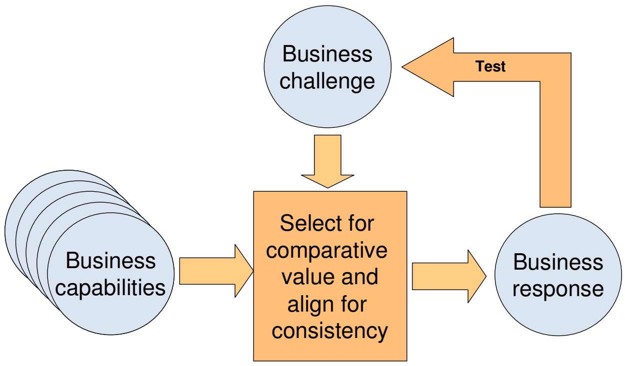


Figure 18: Assembly of business response

Business responses that might be required of Transend include planning, risk management, leadership and stakeholder engagement. In addition, technical capabilities, such as those shown in Figure 19, and set out in more detail in Appendix 3, may be required.

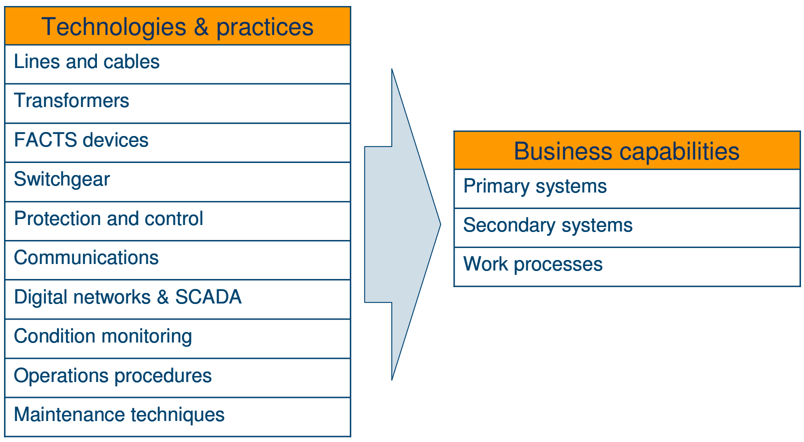


Figure 19: Technical elements of business capability