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The challenges to a truly national energy market

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Introduction

Thank you for inviting me here today to talk about the state of the energy sector—and in particular, some of the challenges that lie ahead.

The theme for this conference is infrastructure—and specifically, the direction and financing of national energy infrastructure in the context of a carbon constrained economy and a world recovering from the perturbations of the global financial crisis.

As the agency responsible for monitoring the conduct and performance of the national electricity market, the AER is uniquely placed to comment on this topic. Our role includes assessing the behaviour of market participants and monitoring the impact of the ensuing price signals on generation investment.

Between the generators and the retailers are the poles and the wires. In this space, the AER determines the revenues of network businesses on the basis of projected efficient costs needed to meet expected demand and licence conditions. The AER must also assess the forecast capital requirements of each business and an appropriate benchmark rate of return. In setting the CAPEX allowance the AER does not specify the type of investment the business must make. Nor does the benchmark cost of capital set the rate of return of a particular business. A business can outperform the benchmark through innovation and efficiency measures. The business will be penalised however if service performance levels are not met.

Industry bodies have been advocating a need for very high levels of investment in the coming years—particularly in light of the Carbon Pollution Reduction Scheme and the expanded Renewable Energy Target. For example, the Energy Networks Association published estimates in February 2009 that climate change policies will increase network costs (including augmentation costs) by around $2.5 billion over the next five years. Similarly, the ESAA published estimates in April 2009 that around $33–35 billion of new generation investment will be needed in the next ten years to accommodate the CPRS and expanded renewable energy target.

The accuracy of these estimates will be tested over time. But the proposition that the energy sector will require very considerable investment in new and replacement infrastructure in the years ahead is certainly true.

The conference outline poses a question and makes an observation. It asks: '*Is regulation allowing private sector innovation and investment*?' Now that is an enduringly important question. Regulatory regimes should always be assessed against efficient investment outcomes. Specifically, whether there is under-investment, or indeed, over-investment in energy assets. Regulators and policy makers should be vigilant on this matter. A regime needs to provide the right incentives to both private and public sector players—bearing in mind that around 75 per cent of electricity network assets are still publicly owned.

I do have some difficulty, however, with one comment in the conference outline, which is set out as a statement of fact. The outline states:

'*In the electricity sector decades of partial privatisation, regulation and unresolved issues to do with climate change have not delivered an environment conducive to long term investment*.'

I believe this statement needs to be examined more closely.

There is indeed some evidence that uncertainty about climate change policies has affected investment planning in electricity generation. If left unresolved, such uncertainty could affect energy security and reliability going forward, due to the long lead time in building new plant.

The second point—on privatisation—is not a matter for the AER to comment on. But the final point—that regulation (presumably economic regulation) has '*not delivered long term investment*' in the energy sector—is totally and absolutely without merit.

To the contrary, my proposition today is that the energy sector is indeed well placed to meet the investment challenges ahead. We need to make some changes (as proposed, for example, by the AEMC in its recent review of climate change impacts). But the basic regulatory framework is well positioned to meet investment requirements. By investment, of course, I mean *efficient* investment—given that the performance of the industry is ultimately judged against the price and quality of energy services to end users.

Energy networks

The energy network sector currently faces a number of challenges—the increasing penetration of embedded generation, enhanced licensing and reliability requirements, the relentless growth of peak demand, and for many networks, the problem of aging assets. There are also a range of challenges associated with climate change policies and the introduction of smart meters and grids.

Investment

The evidence strongly points to significant investment growth in energy networks.

Investment has risen strongly over the past few years and recent regulatory proposals indicate this is likely to continue. The AER completed its first revenue determinations in electricity distribution in April 2009—for the NSW and ACT networks. It also published determinations for the NSW and Tasmanian transmission networks at that time.

A common feature of the determinations was substantial increases in capital and operating expenditure. Investment in electricity distribution will rise by around 80 per cent in NSW and 66 per cent in the ACT in the new five year regulatory cycle. In total, the AER signed off on over $14 billion of distribution investment for NSW and the ACT over the next five years. Across the NEM electricity distribution investment is running at over 40 per cent of the underlying asset base in most networks, over 65 per cent in Queensland and up to 90 per cent in parts of New South Wales.

There is a similar story in transmission, where investment will rise by 73 per cent in NSW and 57 per cent in Tasmania over the current regulatory cycle. In total, transmission investment across the NEM was forecast to rise to over $1.6 billion in 2008–9.

These figures should help debunk any notion of underinvestment. Perhaps a more pertinent perspective may be whether some of the recent increases are excessive. Nonetheless, the AER's recent determinations illustrate that we are cognisant of the pressures currently faced by the networks to deliver services. In particular, the networks face the challenges of:

- meeting load growth and rising peak demand
- replacing ageing and obsolete assets, and
- satisfying more rigorous licensing conditions for network security and reliability.

At the moment the AER is looking at new regulatory proposals for the Queensland and South Australian distribution networks. We are also considering the first access arrangement reviews in gas distribution under the National Gas Law—for NSW and the ACT.

As in NSW, the Queensland and South Australian electricity distributors have proposed substantial increases in investment. In South Australia, ETSA Utilities has proposed a 127 per cent increase in investment over the next five years. In Queensland, ENERGEX and Ergon Energy proposed increases of around 50 per cent. In total, the proposals would involve more than $15 billion of investment in the next regulatory cycle.

There is also substantial investment coming on line in gas distribution. In NSW, Jemena has proposed a 63 per cent increase in investment for its gas networks. ActewAGL has proposed a 227 per cent increase in its capital program for the ACT network.

In addition to step-increases in capital spending, operating and maintenance costs are also rising across the networks. While these costs are rising less sharply than capital spending, the increases are nonetheless substantial.

The Electricity Rules allows network businesses significant discretion as to how they use these allowances. The AER's role is to approve what is needed for efficient service delivery. There are mechanisms within the regime that reward businesses for efficient investment and operating programs—balanced with incentives for reliable services. But ultimately, it is up to each network business to determine how it will use its CAPEX and OPEX allowances.

Retail impacts

With network costs accounting for around 50 per cent of retail costs, rising capital and operating expenditure allowances are flowing through to energy customers—who ultimately must fund these expenditures. In May 2009 the NSW regulator (the Independent Pricing and Regulatory Tribunal) announced that higher network charges would increase the average residential electricity bill in this state by around 10 per cent. The impact on large energy users is even greater. The Energy Users Association has referred to network tariff increases of up to 55 per cent for some large customers in NSW.

ETSA's regulatory proposal would increase distribution charges in South Australia by around 6–7 per cent per year for a small residential customer and 10 per cent for a small business customer. The Queensland proposals would increase distribution charges by around 10 per cent in the first year, followed by annual increases of around 4 per cent.

These examples serve to illustrate that rising network expenditure comes at a very substantial cost to the end consumer. Energy customers will be expecting a return for these price increases. In particular, they will look to reliability outcomes, the types of services offered, and in the longer term, more efficient networks with more competitive and differentiated pricing structures.

Rising capital and operating expenditure over the past few years has enabled the networks to deliver reasonably stable reliability. The average duration of outages per customer in the NEM has been generally around 200–250 minutes per year, allowing for regional variations. Electricity customers will look to network businesses to translate rising investment and operating costs into stable or improving reliability outcomes.

While reliability is one aspect of service delivery, network businesses should also look to improve the range of services offered. For example, demand management has many benefits for consumers—from deferring capital expenditure, to offsetting the needle peaks in energy demand. The AER has introduced a demand management innovation allowance to encourage network businesses to consider non-network augmentations. The scheme allows businesses to recover implementation costs and foregone revenues from introducing demand management measures. While the scheme is in its early stages, it will mature and is likely to become more important over time.

Climate change will clearly impact on the way our electricity grids are operated and developed. The networks will be seeking to harness the potential of smart meters and smart grids to improve service delivery. Smart meters allow customers to track their energy consumption. When combined with appropriate tariff structures, they can reduce peak and overall demand. The Council of Australian Governments has committed to a national rollout of smart meters where the benefits outweigh the costs, with initial deployment in Victoria and New South Wales. The rollout in Victoria began in 2009.

Smart grids take the concept of smart meters further towards direct control of load, the use of communications technology to rapidly detect and switch around faults to minimise supply disruptions, and the integration of embedded generation that can be switched on and off to support the network. The Australian Government recently committed $100 million for a trial of smart grid technologies.

While technological innovations such as smart meters and smart grids will pose operational challenges for the distribution sector, their introduction can be easily accommodated within the regulatory framework. In particular, the Electricity Rules allow for stable returns on investment in new technology—once these assets are in the regulated asset base there is no risk of them being optimised out (or ‘stranded’). In this sense, the ‘brave new world’ of technical innovation of our electricity network is not inherently more risky and does not warrant higher rates of return.

Rather, the cost and risks associated with this technology will be borne by consumers, who will ultimately benefit from improved information about time of day usage and remote control of electrical appliances. These changes will be reinforced through the introduction of time of use energy tariffs that these technologies allow. Over time, energy users will expect to see these kind of improvements in network operation lead to more competitive and differentiated products and tariffs.

And while this ‘smarting’ of the grid will require substantial investment, it does not automatically follow that all of this investment is over and above the existing levels. In many cases I suspect it is about reallocating investment priorities. Ultimately we may see lower capital spending due to better utilisation of the network.

Of course, assessing the prudency and efficiency of proposed smart grid investments by network businesses will present challenges to the regulator. For example assessing the value of bio-directional power flows and facilitating home area networks to help customers make more informed choices is new territory for regulation. But these are not matters for the regulatory framework—rather its implementation.

Review of capital costs

A key element of the energy regulatory framework is the allowable return on capital to network owners—which may account for up to 60 per cent of allowed revenues. In May 2009 the AER released a decision on the parameters of the weighted average cost of capital model, which determines the return on capital for regulated electricity networks. The weighted average cost of capital represents the cost of debt and equity required by an efficient benchmark electricity network business to supply regulated electricity services.

The review covered the rate of return values and methods to be adopted in electricity network pricing determinations over the next five years. It was the first review of its type under the Electricity Rules and its release coincided with the onset of the global financial crisis. Based on the parameters established through the review, the weighted average cost of capital is currently around 10 per cent—reflecting a cost of debt of 9.7 per cent and an equity return of 10.6 per cent.

The AER believes it important to take a long term perspective on the cost of capital. There is no doubt the global financial crisis saw debt and equity margins become more volatile and rise above long term averages. We believe it is important to guarantee stable returns to regulated assets. This requires the regulator to allow returns which provide the right incentives for investment over the long term—in what are long term assets—rather than reacting to shorter term influences that would adjust equity margins up or down, depending on the market conditions of the day.

In the final analysis the AER decision took account of the global financial crisis and recognised potential for a shift in the market's assessment of risk. It also took a cautious approach to interpreting the evidence by adopting values for certain parameters *above* the ranges indicated by empirical estimates.

The decision provides that the cost of capital allowance will compensate businesses for the debt margin relating to a benchmark BBB+ rated bond of 10-years duration, as prevailing at the time of a reset. Since 2007 this has proven to be an increasingly challenging task. There are now very few bonds with a term to maturity beyond 7 years. Since June 2007 the debt margin allowance has risen from around 114 basis points above the 10 year CGS to around 350 basis points.

The equity side is also challenging. While we have this under ongoing review, the best approach in our view is to allow an equity return commensurate with the long run risk profile of network assets. More recent events in financial markets tend to reinforce this view.

Notwithstanding the volatility of the market at the height of the GFC, the AER believes on balance it got the rate of return about right on the basis of information available at the time of the decision. The question as to whether there is a now a new paradigm by way of a permanent upward shift in the equity premium is still open. But conditions in financial markets since April—when the WACC decision was made—appear to have improved significantly, and so far anyway, don't lend particular weight to the 'structural break' theory.

Independent assessments suggest that financial markets have begun to recover from the worst effects of the credit crisis, with the OECD and the RBA recently pointing to more favourable conditions. For example, a rally in equity markets has led to a reduction in the high equity yields observed earlier this year. Similarly, corporate debt markets have continued to improve with declines in credit spreads. In each case, rates have returned to levels more in keeping with those prior to the GFC—and are much closer to those in the AER determination.

On the debt side businesses will be compensated for any rises in debt margins at each reset. This compensation, being based on a BBB+ rating, is currently well above that which higher rated network businesses incur. More generally, evidence from a number of sources suggests that the regulatory regime helps insulate energy network businesses from the type of market volatility that affects businesses operating in contestable markets. Significantly, the ability of a regulated network business to align its debt issuance to the time of a regulatory determination mitigates a large proportion of the risks associated with rising debt costs.

On the equity side, we have seen yields recently fall to between 9 and 12 percent, which is very close to the AER's longer term equity return of around 11 per cent.

National reform measures

While the transition to national energy market regulation has taken some time, we are starting to see the benefits of nationally coherent responses to issues in the market. The transition to national regulation of the networks is now largely complete, with the AER now the economic regulator of all electricity networks and covered gas pipelines in southern and eastern Australia. The AER has taken measures towards a more transparent and consistent approach to regulating the networks—although there are some obvious challenges in moving away from the mix of approaches previously applied by the states and territories. The AER has published a number of guidelines to clarify its approach.

We also saw the establishment of a new body—the Australian Energy Market Operator (AEMO)— on 1 July 2009 as the single electricity and gas market operator in southern and eastern Australia. The new body is also coordinating high level national transmission planning. The goal is to overlay the traditional jurisdiction-based approach to network planning with a more strategic, long-term focus on the efficient development of the grid from a national perspective. To this end, AEMO will publish an annual network development plan to complement shorter term, regional planning. The first network development plan is scheduled for release by the end of 2010.

Another measure at the national level will be a new regulatory investment test to help transmission businesses identify effective ways of responding to rising demand for electricity services—for example, in assessing whether the most efficient response is a network augmentation or an alternative such as generation investment. The new test, which takes effect in August 2010, will take account of the effects of investment on reliability and a range of market impacts. The AER will publish the test and associated guidelines by July 2010.

Similar reforms are underway—but at an earlier stage of development—in distribution. In September 2009, the AEMC recommended a new regulatory test similar to that for transmission. It also recommended more transparent planning requirements, including annual reports that detail projections of load, network capacity, potential limitations and projects for the next five years; and arrangements to jointly plan investment affecting both transmission and distribution networks.

There are also significant developments in gas. The commissioning of the QSN Link in 2009 has interconnected Queensland with the transmission pipeline network spanning NSW, Victoria, South Australia, Tasmania and the ACT. This is moving us closer to a national gas market. For the first time, coal seam gas from Queensland can compete in southern markets with gas produced in the Cooper and Victorian gas basins.

A number of national policy initiatives are underway to promote more transparent and competitive gas markets. The Gas Market Bulletin Board, which began in July 2008, provides real-time information on the state of the gas market, system constraints and market opportunities. To complement it, new spot markets for short term gas trades will begin next winter. The first markets will be based around Sydney and Adelaide. While the markets relate to gas for balancing purposes, they will provide transparent price guidance for the market as a whole.

AEMO is also about to launch a new annual Gas Statement of Opportunities—a national supply and demand statement to help industry formulate its investment plans. The first statement is scheduled for December 2009.

These are all positive advances towards a more integrated national energy market.

Climate change policies

Climate change policies pose a range of challenges and opportunities for the energy sector. In generation, the introduction of the CPRS is likely to improve the competitiveness of gas fired plant in relation to coal fired technology. This is reflected in the extent of gas fired generation in recent and committed investment decisions, including 2400 megawatts of new capacity in

2008–09. Wind generation is also likely to grow significantly under the expanded renewable energy target.

The Australian Energy Market Commission recently completed a review of Australia's energy market frameworks in the light of climate change policies. A key consideration is whether climate change policies will lead to short term generation capacity shortfalls. The increased use of wind generation also raises issues such as inertia and voltage control.

The AEMC found that the market design is generally sound, but recommended some refinements to strengthen the current reliability mechanisms—for example, providing more flexibility for the market operator to procure reserve generation capacity. There are also proposals to enhance demand side response.

From the AER's perspective, the electricity market is well designed to provide price signals on where new generation investment is needed. More generally, the market is underpinned by effective compliance and enforcement arrangements, in which the AER plays an important role.

We are already seeing some investment response to climate change policies, with new gas-fired plant being developed in Queensland, New South Wales and Victoria. In South Australia the response has been mainly in wind generation.

Of course, the market can only deliver efficient signals if it is competitive. Commissioner Willett recently spoke about the types of problems that can occur if price signals are distorted by market power. While I don't intend to go over that ground again today, the AER has publicly noted the apparent exercise of market power in two regions of the NEM earlier this year. The story here is similar to that for the networks—if prices are rising, energy users want to see a justifiable reason.

While much of the debate with climate change has focussed on the generation sector, there are also challenges for the networks. The major challenges include:

- How best to coordinate the connection of new remote generators, such as wind generators, to the network— for example, how to get connection assets built to an efficient scale to accommodate future generation capacity. The AEMC is proposing that transmission businesses size network extensions to remote generators to accommodate anticipated future needs, with customers underwriting the risk of asset stranding. The AER will have a role in ensuring consumers' interests are protected.

- How to get better locational signals for new generation investment to avoid significant increases in network congestion. The AEMC has proposed a form of generator transmission use of system charge.

Conclusion

This is an interesting and challenging time for the energy industry. The transition to national regulation is largely complete, bringing much greater transparency and consistency in the regulatory framework. We now have a single national regulator and a single national energy market operator across gas and electricity. There are also major reforms, like national transmission planning, underway.

There is ample evidence, as I think I've shown, that the new regulatory framework has been delivering on the substantial investment programs that are needed in some networks. The rate of return review has also delivered good outcomes for the industry in a time of global financial uncertainty.

While the regulatory process has been delivering some big headline numbers on investment, the onus is now on the networks to deliver. Every dollar of CAPEX and OPEX is paid for by energy customers, and it is part of the regulator's role to ensure they receive value for money.

I think there is also a role for network businesses to communicate more effectively with customers about the benefits they are receiving for higher energy prices. If rising investment translates into more secure networks and enhanced reliability, this is a message that needs to be sold. Similarly, the benefits of solutions like demand management and smart meters and grids need to be actively promoted and pursued.

The key message, I think, is that the step increases we are seeing in investment will need to translate into measurable outcomes for consumers. If this fails to materialise, the industry will have some serious questions to answer.

Thank you.