NERA
ECONOMIC CONSULTING

Regulatory Change Management and the RET Scheme Review

A report for Trustpower

16 May 2014

Project Team

Greg Houston

Karl McDermott

Brendan Quach

Ehson Shirazi

Dale Yeats

NERA Economic Consulting
Darling Park Tower 3
201 Sussex Street
Sydney NSW 2000
Tel: 61 2 8864 6500 Fax: 61 2 8864 6549
www.nera.com

Contents

Executive Summary

On 17 February 2014, the Australian government commenced a review of the operation, costs and benefits of the *Renewable Energy (Electricity) Act 2000* (REE Act) and related legislation and regulations, and the Renewable Energy Target (RET) scheme constituted by these instruments. Within this context, Trustpower Ltd (Trustpower) has asked NERA Economic Consulting (NERA) to prepare a report that considers how best to manage regulatory changes that may arise from any proposed reforms to the RET scheme, including reforms that have the potential to reduce or remove payments to existing renewable electricity generators.

Background to the RET scheme and review

The RET scheme creates a guaranteed market for additional renewable energy deployment using a mechanism of tradable certificates. Supply of these certificates is provided by renewable energy generators and owners of small-scale renewable energy systems, which are entitled to create certificates according to the volume of electricity produced or displaced. Demand for these certificates is created by placing a legal obligation on liable entities (usually electricity retailers) to source and surrender a certain quantity of certificates to the Clean Energy Regulator to demonstrate their compliance with annual obligations. The trade in these certificates provides a financial incentive for investment in renewable power stations, and for the installation of small-scale renewable energy systems.

From 1 January 2011, the RET scheme was separated into two distinct parts – the Large-scale Renewable Energy Target (LRET), and the Small-scale Renewable Energy Scheme (SRES) – each with separate certificate markets and separate obligations for liable entities:[1]

- the LRET creates a financial incentive for the establishment and growth of renewable energy power stations, such as wind and solar farms, and hydro-electric power stations, by entitling eligible power stations to create Large-scale Generation Certificates (LGCs) according to how much additional renewable electricity they produce above their baseline, and legislating demand for these LGCs by liable entities; and
- the SRES was designed to assist households and small businesses with the upfront cost of installing small-scale renewable energy systems, such as solar photovoltaic systems and solar water heaters, by allowing owners of eligible systems to create Small-scale Generation Certificates (STCs) upon installation of the system, and a legal obligation on liable entities to purchase these STCs.

On 17 February 2014 the Australian government commenced a review of the operation, costs and benefits of the REE Act and related legislation and regulations, and the RET scheme constituted by these instruments.[2]

---

1 Clean Energy Regulator, *About the Renewable Energy Target*, April 2012, pp.7-14.

2 The Hon. Greg Hunt MP, and the Hon. Ian Mcfarlane MP, *Media Release – Review of the Renewable Energy Target*, 17 February 2014.

The Terms of Reference for the review state that it will cover:[3]

- the economic, environmental and social impacts of the RET scheme, in particular the impacts on electricity prices, energy markets, the renewable energy sector, manufacturing sector and Australian households;
- the extent to which the formal objects of the REE Act are being met; and
- the interaction of the RET scheme with other Commonwealth and State/Territory policies and regulations.

The review will provide advice on:[4]

- whether the objective of the RET scheme, to deliver 41,000 GWh and small scale solar generation by 2020, is still appropriate;
- the extent of the RET's impact on electricity prices, and the range of options available to reduce any impact while managing sovereign risk;
- the operation of the small-scale and large-scale components of the RET and their interaction;
- implications of projected electricity demand for the 41,000 GWh target; and
- implementation arrangements for any proposed reforms to the RET, including how to manage transition issues, risks and adjustment costs that may arise from policy changes to the RET.

Sovereign and regulatory risk

Government policies and the regulatory arrangements that enact them are critical to determining the basis for cost recovery and the perceived risk of not recovering the cost of an investment. Changes in policies that substantially affect the basis of, and prospects for, investor cost recovery need to be handled with a great deal of care and sensitivity if significant loss of investor confidence is to be avoided.

Governments or regulatory authorities with a track-record of making substantial and/or ex-post adjustments that affect investors' reasonably anticipated returns will reduce the confidence of existing and future investors in the stability of policies and regulatory arrangements. This can be considered as a form of sovereign and regulatory risk.

Sovereign risk increases the likelihood that investors' expectations as to the return on or return of capital will not be met, and so increases a firm's cost of providing capital. An increase in the cost of capital in the electricity industry will:

- increase the cost of providing services;
- increase electricity prices;

---

3 *Renewable Energy Target Review – Terms of Reference*, February 2014.

4 *Renewable Energy Target Review – Terms of Reference*, February 2014.

- result in under-investment; and
- dampen the effectiveness of price signals.

In addition, significant changes in government policy in the electricity industry could affect investor confidence in other, regulated, industries. It is highly likely that investors in other industries will consider policy changes in the electricity industry to be a meaningful signal of the government's commitment to regulatory arrangements more broadly. Thus, a perceived increase in sovereign risk in the electricity industry is likely to have implications for investment decisions in, for example, the water, telecommunications and gas industries.

It follows that it is important to consider the extent to which an amendment to payments under the RET scheme will increase the level of perceived sovereign risk in Australia.

Effect on existing investors in renewable generation

Any amendment to the RET scheme that reduces or removes payments to existing generators under the LRET and/or SRES would have the effect of reducing the return on investments in renewable electricity generation. This would inevitably reduce the incentives for investing in new large-scale and small-scale renewable electricity generation, and will also reduce the incentives for existing renewable energy power stations to produce electricity. Such a change would therefore be inconsistent with the objectives of the RET scheme of encouraging additional generation of electricity from renewable sources and reducing emissions of greenhouse gases.

Any such amendment is likely to result in a substantial transfer of wealth from existing investors in renewable generators to other industry participants and, unless appropriate transitional measures are put in place, an increase in the level of sovereign risk perceived in relation to the Australian electricity sector and, potentially, other regulated industries.

An increase in perceived sovereign would increase the cost of raising capital in the affected industries. This would ultimately increase the price to consumers of regulated services and may inefficiently reduce or delay investment.

Change management measures

In the regulatory context, the adverse effects of sovereign risk mean that best-practice regulators generally seek to minimise the risk of unanticipated change through the inclusion of change management arrangements as part of a package of any changes that are likely to have an adverse effect on the financial position of existing parties operating within and subject to a particular regulatory framework.

The principal objective of such arrangements is to minimise the effects of unanticipated changes to existing stakeholders, without compromising the long-term efficiency benefits of the reforms. The inclusion of effective change management arrangements enhances the stability and predictability of the returns of investors, which in turn fosters an environment conducive to investment in long lived assets.

Conclusion

An unanticipated change in the RET scheme that significantly reduces or removes RET payments would result in an unforeseen wealth transfer from existing investors to other industry participants and, consequently, a reduction in the confidence of existing and future investors in Australian regulated industries in the government upholding its policies.

The consequences of an increase in perceived sovereign risk are that investors will demand a higher rate of return to invest in regulated industries, which will:

- increase the cost of providing services;
- increase prices;
- result in under-investment; and
- dampen the effectiveness of price signals.

In our opinion, amending payments under the RET scheme in a way that increases perceived sovereign risk will not promote the efficient operation of, or reliable supply by, the electricity industry and will ultimately not benefit consumers. We conclude that, taken by itself, a reform that removes or reduces RET payments for existing renewable electricity generators is unlikely to be consistent with this overarching objective of electricity regulation.

Furthermore, to the extent that investors in other industries consider the government's decisions in the electricity industry to be a signal of policy commitment more generally, there will likely be unintended consequences for the cost of capital, prices and investment decisions in other regulated industries.

If the government were to conclude that the existing RET scheme should be amended, it will be critical to take account of the financial interests of existing investors in renewable electricity generation. In order to minimise the adverse effect of increased sovereign and regulatory risk, the government should ensure that existing investors are sufficiently compensated for departures from the returns they would reasonably have been anticipated under the existing, long-standing regulatory arrangements. The cost of any such compensation should also be taken into account in the analysis underpinning any decision to amend the scheme.

1. Introduction

On 17 February 2014, the Australian government commenced a review of the operation, costs and benefits of the *Renewable Energy (Electricity) Act 2000* (REE Act) and related legislation and regulations, and the Renewable Energy Target (RET) scheme constituted by these instruments. The review will provide advice on a number of things, including:

- whether the objective of the RET scheme, to deliver 41,000 GWh and small scale solar generation by 2020, is still appropriate;
- the extent of the RET's impact on electricity prices, and the range of options available to reduce any impact while managing sovereign risk;
- the operation of the small-scale and large-scale components of the RET and their interaction;
- implications of projected electricity demand for the 41,000 GWh target; and
- implementation arrangements for any proposed reforms to the RET, including how to manage transition issues, risks and adjustment costs that may arise from policy changes to the RET.

Within this context, Trustpower Ltd (Trustpower) has asked NERA Economic Consulting (NERA) to prepare a report for public submission which considers how best to manage policy change from any proposed reforms to the RET scheme, including reforms which reduce or remove payments to renewable energy generators.

Our report is structured as follows:

- section 2 describes the relevant background;
- section 3 discusses sovereign and regulatory risk and the effects of amending RET payments on existing renewable energy generators;
- section 4 sets out examples in which overseas regulatory authorities have implemented reforms that use change management arrangements to mitigate sovereign risk; and
- section 5 provides concluding comments.

2. Background

In this section, we provide a summary of the RET scheme as it currently operates, as well as the review of the scheme which is presently being undertaken by the Australian government.

2.1. Objectives of the scheme and the regulator

The objectives of the RET scheme are to:[5]

- encourage additional generation of electricity from renewable sources;
- reduce emissions of greenhouse gases; and
- ensure that renewable energy sources are ecologically sustainable.

The scheme was introduced in 2001, and was initially designed to increase the proportion of renewable energy in Australia's energy mix by an additional 2 per cent by 2010.[6] From 2010, the scheme was expanded to ensure that the equivalent of at least 20 per cent of Australia's electricity will come from renewable sources by 2020.[7]

The RET scheme is facilitated by the Clean Energy Regulator (Regulator). The role of the Regulator is to:

- ensure the integrity of renewable energy certificates created (supply side of the market);
- ensure the integrity of renewable energy certificates surrendered to acquit liability (demand side of the market); and
- provide the registry that facilitates administration of renewable energy certificates by market participants.

2.2. Operation of the scheme

The RET scheme creates a guaranteed market for additional renewable energy deployment using a mechanism of tradable certificates. Supply of these certificates is provided by renewable energy generators and owners of small-scale renewable energy systems, which are entitled to create certificates according to the volume of electricity produced or displaced. Demand for these certificates is created by placing a legal obligation on liable entities (usually electricity retailers) to source and surrender a certain quantity of certificates to the Clean Energy Regulator to demonstrate their compliance with annual obligations. The trade in these certificates provides a financial incentive for investment in renewable power stations, and for the installation of small-scale renewable energy systems, such as solar photovoltaic systems and solar water heaters.

---

5 *Renewable Energy (Electricity) Act 2000*, s3.

6 *Review of the Renewable Energy Target – Call for Submissions*, 5 April 2014, p.3.

7 *Review of the Renewable Energy Target – Call for Submissions*, 5 April 2014, p.3.

From 2001 to the end of 2010, the commodity in the market was called a 'Renewable Energy Certificate' (REC). However, from 1 January 2011, the RET scheme was separated into two parts – the Large-scale Renewable Energy Target (LRET), and the Small-scale Renewable Energy Scheme (SRES) – each with separate certificate markets and separate obligations for liable entities. Under this iteration of the scheme, RECs were re-classified into two certificate types: 'Large-scale Generation Certificates' (LGCs) and 'Small-scale Generation Certificates' (STCs).

The operation of the LRET and SRES are discussed in further detail below.

2.2.1. Large-scale Renewable Energy Target

When the RET scheme was originally established in 2001, the intention was to encourage both additional generation of electricity from existing renewable energy power stations, and - the development of new renewable energy projects.

In line with this, the LRET creates a financial incentive for the establishment and growth of renewable energy power stations, such as wind and solar farms, and hydro-electric power stations, by entitling eligible power stations to create LGCs according to how much additional renewable electricity they produce above their baseline, and legislating demand for these LGCs by liable entities. LGCs are often sold together with electricity supply in Power Purchase Agreements, but are also tradeable on spot markets where prices have historically fluctuated between $10 and $60 per LGC.[8] The revenue earned by the power station for the sale of LGCs is additional to that received for the sale of the electricity generated.

A power station will only be entitled to create LGCs if it has been accredited under the REE Act. Accreditation requires that some or all of the power generated by the power station is produced from an eligible renewable energy source, such as solar energy, wind, ocean waves and tides, agricultural waste, etc.[9] During the accreditation process, the Regulator is required to determine the baseline level of electricity generation.[10] Once accredited, a power station can create one LGC for each whole megawatt hour of renewable electricity generated above their baseline.[11]

The LRET includes legislated annual targets of renewable energy to be generated by power stations for every year up to 2030. The current targets are set out in Table 2.1.

---

8 Clean Energy Regulator, *About the Renewable Energy Target*, April 2012, p.8.

9 A complete list of eligible renewable energy sources is set out in section 17 of the REE Act.

10 The baseline level is generally the average amount of renewable electricity generated over the years 1994, 1995 and 1996. Power stations which only commenced operation after 1 January 1997 have a baseline of zero.

See: Clean Energy Regulator, *About the Renewable Energy Target*, April 2012, p.7.

11 *Renewable Energy (Electricity) Act 2000*, s19.

Table 2.1
Annual Targets for Large-scale Renewable Energy

Year	Target (GWh)	Year	Target (GWh)
2011	10,400	2017	26,031
2012	16,763	2018	30,631
2013	19,088	2019	35,231
2014	16,950	2020	41,850
2015	18,850	2021-2030	41,000
2016	21,431		

Source: Clean Energy Regulator, *About the Renewable Energy Target*, April 2012, p8

A liable entity must meet its LRET obligations by surrendering a certain number of LGCs to the Clean Energy Regulatory each year. The number of LGCs that an entity must surrender is calculated by multiplying the entity's total megawatt hours of electricity purchased in a particular year by the Renewable Power Percentage (RPP). The RPP is calculated annually in advance of the year for which it will apply, and takes into account:[12]

- the required amount of renewable electricity for the year (ie, the LRET);
- the estimated amount of electricity that will be acquired by liable entities in the year;
- any under or over surrender of LGCs against the annual targets of previous years; and
- the amount of all partial exemptions expected to be claimed for the year.

If a liable entity fails to surrender a sufficient number of certificates, it must pay an administrative penalty.[13]

2.2.2. Small-scale Renewable Energy Scheme

The SRES was designed to assist households and small businesses with the upfront cost of installing small-scale renewable energy systems, such as solar photovoltaic systems and solar water heaters. This is achieved by allowing owners of eligible systems to create STCs upon installation of the system, and a legal obligation on liable entities to purchase these STCs. The money earned from the sale of STCs allows the owners of small-scale renewable energy systems to immediately offset some of the upfront installation costs of the investment.

A small-scale renewable energy system is eligible for the SRES if it meets certain legislated requirements, including that the system is new and was installed by a Clean Energy Council accredited installer. The number of STCs a system can create is based on the volume of electricity (in megawatt hours) that the system produces or displaces. For instance:[14]

---

12 Clean Energy Regulator, *About the Renewable Energy Target*, April 2012, p.8.

13 The shortfall charge is currently set at $65 for each LGC which is not surrendered.

14 Clean Energy Regulator, *About the Renewable Energy Target*, April 2012, p.12.

- the installation of an eligible solar photovoltaic system creates STCs equivalent to the number of megawatt hours of electricity that the system is expected to be generated over the course of its lifetime up to 15 years; while
- the installation of an eligible solar water heater creates STCs equivalent to the number of megawatt hours of electricity that the system is expected to displace over the course of its lifetime up to 10 years.

The number of STCs that will be created for each small-scale renewable energy system will therefore vary depending on the type of system, the size and capacity of the system, as well as geographic location. The number of STCs is also affected by a mechanism known as ‘solar credits,’ which effectively provide ‘bonus’ STCs for the first 1.5 kW of on-grid, and 20kW of off-grid, capacity installed in an eligible location.[15] In addition, note that the SRES, unlike the LRET, does not have binding targets on the number of STCs that need to be generated in any given year. Leaving the scheme uncapped in this manner ensures that all eligible installations receive assistance.

A liable entity must meet its SRES obligations by surrendering a certain number of STCs to the Clean Energy Regulatory each quarter. The number of STCs that an entity must surrender is calculated by multiplying the entity’s total megawatt hours of electricity purchased in a particular year by the Small-scale Technology Percentage (STP). The STP is calculated annually in advance of the year for which it will apply, and takes into account estimates of:[16]

- the number of STCs that are expected to be created during the year;
- the volume of electricity that is expected to be acquired by liable entities in the year; and
- the amount of all partial exemptions expected to be claimed for the year.

In a similar fashion to the LRET, if a liable entity does not surrender a sufficient number of STCs, it must pay an administrative penalty.

2.2.3. Liable entities

As explained above, the obligation to purchase LGCs and STCs falls on ‘liable entities.’ A ‘liable entity’ is defined under the REE Act as an entity which make a ‘relevant acquisition of electricity’ in a given year.[17] A ‘relevant acquisition’ is comprised of both:

- the purchase of electricity from the wholesale market; and[18]
- the purchase of electricity by an end-user directly from a generator.[19]

An acquisition of electricity is not considered a ‘relevant acquisition’ if:[20]

---

15 Clean Energy Regulator, *About the Renewable Energy Target*, April 2012, p.12.

16 Clean Energy Regulator, *About the Renewable Energy Target*, April 2012, p.13.

17 *Renewable Energy (Electricity) Act 2000*, s35.

18 *Renewable Energy (Electricity) Act 2000*, s32.

19 *Renewable Energy (Electricity) Act 2000*, s33.

- the electricity was delivered on a grid that has a capacity that is less than 100 MW and that is not, directly or indirectly, connected to a grid that has a capacity of 100 MW or more; or
- the end user of the electricity generated the electricity and either of the following conditions are satisfied:
  - the point at which the electricity is generated is less than 1 kilometre from the point at which the electricity is used;
  - the electricity is transmitted or distributed between the point of generation and the point of use and the line on which the electricity is transmitted or distributed is used solely for the transmission or distribution of electricity between those 2 points; or
- the electricity is later acquired by NEMMCO or a person or body prescribed by the regulations.

Under this definition, the RET scheme predominantly imposes an obligation to purchase certificates on electricity retailers.

2.3. Exemptions

The RET scheme contains two exemptions.

The first is a partial exemption for electricity used in prescribed emissions-intensive trade-exposed (EITE) activities, such as the production of glass containers and bulk flat glass, integrated production of lead and zinc, manufacture of newsprint and cartonboard, and petroleum refining.[21] This exemption is intended to help EITE businesses that compete in international markets where their competitions do not face similar costs. The level of exemption depends on the emissions intensity of the activity.

The second exemption is for entities generating their own electricity. In order to be eligible for this exemption, a self-generator (on a grid of greater than 100 MW capacity) must:

- produce and use the electricity for themselves with no take-off from a third party; or
- in cases where the self-generator is the primary, but not the only, user, the electricity must be used within a one kilometre radius of its production by the entity that generated it.

2.4. Review of the scheme

On 17 February 2014, the Australian government commenced a review of the operation, costs and benefits of the REE Act and related legislation and regulations, and the RET scheme constituted by these instruments.[22]

---

[20] *Renewable Energy (Electricity) Act 2000*, s31.

[21] A full list of eligible EITE activities is included in schedule 6 of the *Renewable Energy (Electricity) Regulations 2001*.

[22] The Hon. Greg Hunt MP, and the Hon. Ian Mcfarlane MP, *Media Release – Review of the Renewable Energy Target*, 17 February 2014.

The Terms of Reference for the review state that it will cover:[23]

- the economic, environmental and social impacts of the RET scheme, in particular the impacts on electricity prices, energy markets, the renewable energy sector, manufacturing sector and Australian households;
- the extent to which the formal objects of the REE Act are being met; and
- the interaction of the RET scheme with other Commonwealth and State/Territory policies and regulations.

The review will provide advice on:[24]

- whether the objective of the RET scheme, to deliver 41,000 GWh and small scale solar generation by 2020, is still appropriate;
- the extent of the RET's impact on electricity prices, and the range of options available to reduce any impact while managing sovereign risk;
- the operation of the small-scale and large-scale components of the RET and their interaction;
- implications of projected electricity demand for the 41,000 GWh target; and
- implementation arrangements for any proposed reforms to the RET, including how to manage transition issues, risks and adjustment costs that may arise from policy changes to the RET.

Following the release of the Terms of Reference, the expert panel appointed to undertake the review released a 'Call for Submissions' which, amongst other things, identified a number of economic impacts of the RET scheme. These impacts are summarised briefly below:[25]

- **impact on the renewable energy sector** – the panel recognises that the RET scheme has contributed to a significant increase in investment and employment in the renewable energy sector, particularly in the small-scale industry. Notwithstanding this, meeting the current 41,000 GWh large-scale target by 2020 requires a significant increase in the amount of new renewable capacity to be built each year from 2015 to 2020. The panel also noted that when the RET was split into the LRET and SRES, the SRES was expected to contribute between 4,000 to 6,000 GWh of renewable generation to the 2020 target, but more recent projections suggest this figure could be closer to 10,000 GWh;
- **impact on energy markets –** the panel noted that national electricity demand has been falling since 2008-09, and projections for demand in 2020 are significantly lower than what projected when the RET scheme commenced. It follows that if the 41,000 GWh target is achieved, the RET could deliver more than a 20 per cent share of renewables. Given these trends, the panel notes that the RET is bringing forward generation capacity that may otherwise not be required under after 2020, which may contribute to fossil fuel

23 *Renewable Energy Target Review – Terms of Reference*, February 2014.

24 *Renewable Energy Target Review – Terms of Reference*, February 2014.

25 *Review of the Renewable Energy Target – Call for Submissions*, 5 April 2014, pp.7-9.

generators being mothballed or curtailed. The panel also noted that the RET scheme raises two issues which affect systems operations and networks, specifically:

 - the issue of system reliability, when renewable resources are variable; and
 - the issue of how to best reflect the full costs and benefits of distributed energy sources, particularly since the increase in distributed generation contributes to higher network charges as network businesses seek to recover costs from fewer units of energy sold;

- **impact on electricity prices** – the panel notes that the RET scheme influences electricity prices in two ways, namely:
  - by placing costs on liable entities who are required to purchase certificates to comply with the scheme, which are then passed onto consumers; and
  - by influencing wholesale electricity prices through the stimulation of investment in renewable generation capacity that would not otherwise be forthcoming

  The panel also noted that the SRES comprised around 60 per cent of the RET costs in 2012-13, largely due to the high uptake of PV systems incentivised by State and Territory Government feed-in-tariffs and the solar credits multiplier under the RET, and falling system costs. However since these incentives have been wound back, STC prices have been less volatile and the cost of the SRES is expected to fall;

- **impact on households** – the Australian Energy Market Commission (AEMC) estimates that the cost of certificates passed onto consumers by liable entities will account for around four per cent of residential retail electricity prices in 2013-14, although this varies by state and territory. The panel also notes that the impact of the RET is not uniform – while some households have benefited from the installation of small-scale technologies, all electricity consumers share the costs of the RET. In addition, increasing electricity prices are disproportionately felt by low-income households, who spend a greater share of their income on electricity, and may face barriers to accessing more efficient appliances and small-scale renewable technology; and

- **impact on businesses** – the panel recognises that the RET scheme includes exemptions for businesses conducting highly emissions-intensive activities (such as aluminium smelting), and those self-generating electricity. Businesses in the former category have received assistance for the costs of the RET scheme for around 65 to 80 per cent of the electricity use related to that activity, but still face the cost of the RET for the proportion of electricity not exempt. The panel also notes that the cost impact the RET scheme for an average Small and Medium Enterprise (SME) consuming 140 MWh of electricity has been estimated to be $337 per year over the period 2013 to 2031.

2.5. Context for this report

It is in the context set out above that this report considers the effects of amending the RET scheme, particularly in relation to reducing or removing payments under the LRET and/or SRES, and the consequences of such changes for sovereign and regulatory risk. Our report also describes how the Australian government could mitigate any perceived increase in such risk, having regard to regulatory best practice.

3. Economic Policy and the Prospects for Cost Recovery

This section discusses the economic regulation of electricity, as directed by government policy, with specific regard to the principle of cost recovery, as well as the effect of ex-post adjustments to the returns that can be expected by existing investors, and so the perceived degree of sovereign and regulatory risk.

3.1. The economic regulation of electricity

Electricity markets are often characterised by the significant involvement of policy-makers and regulators, the decisions of which have a profound influence on investment and operational decisions by participants at each functional level of the electricity supply chain. Such decisions affect, for example:

- the rules by which grid-connected generators are scheduled, dispatched and compensated under various forms of wholesale market design;
- the determination of which market participants (primarily, generators and/or network users), pay for the cost of providing the transmission network, and on what basis; and
- the determination of maximum prices for the use of transmission and distribution networks.

The potentially complex arrangements by which these decisions are made can substantially affect the revenue that can be expected to accrue from capital invested at each and every element of the supply chain. In recognition of the intrinsic nature of government policies and regulatory rules in determining the expected remuneration of electricity sector investment decisions, a number of core principles have been established for taking account of the interests of investors in both making and amending policies and rules. These include:

- cost recovery – investors must have a reasonable opportunity to recover the cost of their investment, including an appropriate return on that investment; and
- policy and regulatory risk – the government and regulators should generally seek to maximise the degree of certainty and predictability associated with future regulatory arrangements.

3.1.1. Cost recovery

A reasonable prospect of cost recovery is a necessary precondition for efficient private sector investment in the electricity industry. It therefore underpins the delivery of reliable supply, which is in the long-term interests of consumers, and is consistent with the government's objective of encouraging additional generation of electricity from renewable sources.

In addition to affecting decisions regarding new investment, an increase in the level of perceived risk of under-recovering costs can also increase the required return on existing investment. If a business becomes less sure of its ability to continue recovering the costs of existing investments, it will seek to increase the immediate return on those investments to offset this risk. This may result in higher prices to consumers.

3.1.2. Sovereign and regulatory risk

Government policies and the regulatory arrangements that enact them are critical to determining the basis for cost recovery and the risk of not recovering the cost of an investment. Changes that substantially affect the basis of, and prospects for, investor cost recovery need to be handled with a great deal of care and sensitivity if a significant reduction in investor confidence is to be avoided.

Certain policy decisions can reduce the prospect of investors' ability to fully recover their costs, including the return on and of capital for a particular project. This could involve, for example:

- an unanticipated change in the application of existing regulatory rules, process or criteria for assessing a regulated firm's cost recovery opportunities; or
- the introduction of new or different rules that affect the prospects for cost recovery of existing investments.

Unexpected significant changes in a policy stance, and the regulations that implement those policies, will reduce investors' confidence in the stability of future arrangements. This is a form of sovereign risk, as it can be interpreted as the risk of the government reneging on an (implicit) agreement with investors. A reduction in investors' confidence in the stability of regulatory arrangements will, ultimately, increase the cost of raising capital.

Significant changes in government policy in one industry could affect investor confidence in other, regulated, industries if such changes are interpreted as a signal of the government's commitment to regulatory arrangements more broadly. Thus, a perceived increase in sovereign risk in the electricity industry is likely to have implications for investment decisions in, for example, the water, telecommunications and gas industries.

The need to ensure that changes in regulatory arrangements minimise the perception of increasing risks is a core principle of best practice economic regulation. Section 4 of this report outlines a number of examples of regulators (or government bodies) making decisions that involve arrangements specifically designed to reduce the risk of unanticipated change, thereby acting to minimise perceived regulatory risk.

3.1.2.1. Credit rating agency's consideration of regulatory risk

The importance of regulatory risk is underlined by its explicit status as a key consideration by credit rating agencies when evaluating default ratings for corporate debt.

Moody's Investor Services

Moody's Investor Services (Moody's) evaluates four, equally weighted, key factors when assessing credit ratings in the regulated electricity sector, one of which is the regulatory framework.

Moody's describes the regulatory framework as the foundation for the way that all decisions affecting utilities are made, as well as the predictability and consistency of that decision-making. Further, half of Moody's evaluation of the regulatory framework factor consists of an evaluation of the consistency and predictability of the regulation. In relation to the consistency and predictability sub-factors, Moody's considers:[26]

> *"… the track record of regulatory decisions in terms of, consistency, predictability and supportiveness."*

Standard & Poor's

Standard & Poor's also recognises that the regulatory framework is of critical importance when assessing regulated utilities' credit risk.[27] Standard & Poor's assessment of the regulatory framework focuses on a utility's ability to recover its costs and earn a timely return by reference to four pillars, one of which is regulatory stability. Standard and Poor's assesses regulatory stability with reference to:[28]

- predictability that lowers uncertainty for the utility and its stakeholders; and
- consistency in the regulatory framework over time.

3.1.2.2. Effects of regulatory risk

The long term interests of customers will be best served by regulators acting so as to minimise the uncertainty associated with the returns to capital. Investing in infrastructure involves substantial upfront investments and uncertain future revenues. Governments and regulatory authorities with a track-record of making substantial and/or ex-post adjustments that affect investors' returns will increase the level of unpredictability in the regulatory environment and, in so doing, substantially increase the perceived risk of investing.

An increase in perceived risk will increase the cost of capital because investors will require a higher rate of return to compensate for the increased risk. This, in turn, affects the entry decisions of potential investors, since capital investment in the electricity sector (and potentially other regulated industries) will not be so readily forthcoming unless investors expect to derive a return at least sufficient to recover the cost of capital. It follows that an unnecessary increase in regulatory risk may deter or delay investment.

Regulatory authorities can encourage behavioural change by providing economic incentives in the form of subsidies. Subsidies can be used to incentivise industry participants such that pursuing their financial self-interest results in behaviour that is consistent with regulatory policy objectives. For example, a regulatory authority could encourage more investment in infrastructure by increasing the rate of return on capital, thereby incentivising potential investors by making investment in regulated infrastructure comparatively more attractive.

Importantly, the effectiveness of the behavioural change that administratively-determined price signals seek to achieve is likely to be reduced to the extent that associated regulatory arrangements contribute to the perception of risk. This is because investors are likely to

---

[26] Moody's Investor Services, Ratings Methodology: Regulated Electric and Gas Utilities, December 2013, page 13.

[27] Standard & Poor's, Utilities: Key Credit Factors for the Regulated, 20 November 2013, paragraph 21

[28] Standard & Poor's, Utilities: Key Credit Factors for the Regulated, 20 November 2013, paragraph 24.

perceive the regulator's commitments, ie, the form or basis for the price signals that it establishes, as less credible.

3.1.3. Change management measures

Reforms that affect the returns received by an investment will generally alter future investment decisions but have a much lesser effect on the behaviour of existing stakeholders. For example, regulatory reforms that reduce the returns earned by a particular type of investment will discourage new investment, but generally do not result in the infrastructure facilities operated by existing participants shutting down. Such reforms therefore give risk to greater regulatory risk by imposing an ex-post windfall loss on existing investments.

The adverse effects of regulatory risk mean that best-practice regulators generally seek to minimise risk through the inclusion of change management arrangements as part of a package of changes that are likely to have an adverse effect on the financial position of existing parties operating within and subject to a particular regulatory framework.

The principal objective of such arrangements is to minimise the effect of the changes to existing investors, without compromising the long-term efficiency benefits of the reforms. In other words, change management arrangements seek to minimise the financial impact of the reforms on exiting investments while still ensuring that the amended price signals are able to guide new investments.

The inclusion of effective change management arrangements enhances the stability and predictability of the returns of investors, which in turn fosters an environment conducive to investment in long lived assets.

3.2. Relevance to the RET review

An amendment to the RET scheme that reduces or removes payments under the LRET and/or SRES would have the effect of reducing the return on investments in renewable electricity generation. This would inevitably reduce the incentives for investing in new large-scale and small-scale renewable electricity generation, and will also reduce the incentives for existing renewable energy power stations to produce electricity. Such a change would therefore be inconsistent with the objectives of the RET scheme of encouraging additional generation of electricity from renewable sources and reducing emissions of greenhouse gases.

Another consequence of reducing or removing payments under the LRET and/or SRES is that it would result in a substantial ex-post transfer of wealth from existing investors in renewable electricity generation to other industry participants, thereby increasing the level of regulatory risk perceived in relation to the Australian electricity sector. An increase in regulatory risk will increase the cost of capital in the electricity industry by:

- increasing the cost of providing electricity services;
- resulting in under-investment; and
- dampening the effect of existing or future price signals.

An increase in the cost of capital in the electricity industry reduces efficiency, since the provision of future electricity services becomes more expensive. Further, an increase in the cost of capital may reduce and/or delay efficient investment, which neither promotes the reliable supply of electricity, nor is to the long-term benefit of consumers.

In our opinion, amending payments under the RET scheme in a way that increases regulatory risk in the electricity industry will not promote the efficient operation of, or reliable supply by, the electricity industry and will ultimately not benefit consumers. We conclude that, taken by itself, a reform that removes or reduces RET payments for existing renewable electricity generators is unlikely to be consistent with this overarching objective of electricity regulation.

If the government were to conclude that the existing RET scheme should be amended, it will be critical to take account of the financial interests of existing investors in renewable electricity generation. In order to minimise the adverse effect of increased sovereign and regulatory risk, the government should ensure that existing investors are sufficiently compensated for departures from the returns they would reasonably have been anticipated under the existing, long-standing regulatory arrangements. The cost of any such compensation should also be taken into account in the analysis underpinning any decision to amend the scheme.

The following chapter sets out examples in which, faced with similar circumstances, best-practice international regulatory authorities have developed and implemented change management measures.

4. Change Management for Assisting Cost Recovery

This section sets out a range of international case studies of regulatory change management arrangements that have been designed specifically to meet the objective of maintaining or reinforcing investor expectations of cost recovery. These change management arrangements have allowed regulators to avoid or mitigate increases in the level of regulatory risk, without materially compromising the benefits of the reforms.

4.1. Australian case studies

4.1.1. Carbon tax

In February 2011 the then Australian Prime Minister announced a plan for a carbon pricing mechanism commencing on 1 July 2012. The objective of the plan was to cut pollution, tackle climate change and deliver the economic reform necessary for Australia to move to a clean energy future.[29]

The emissions trading scheme was established in the Clean Energy Act 2011 and required Australia's largest emitters of carbon dioxide, a substantial proportion of which were fossil fuelled electricity generators, to purchase permits for each tonne of carbon dioxide emitted. This reform was expected to place a significant burden on businesses and, in recognition of this, was accompanied by a number of change management arrangements that sought to minimise the financial shock to existing investors.

First, the carbon price was fixed for each of the first three years to provide certainty to affected businesses. Second, the jobs and competitiveness program provided assistance in the form of free carbon permits to entities that undertake emissions-intensive trade-exposed activities, ie, those entities that produce a lot of emissions but do not have the ability to pass on the associated change in costs in global product markets.[30]

Third, direct assistance was provided to affected industries. For example, the Steel Transformation Plan (STP) provided approximately $450 million to assist the steel industry to transform into an efficient and economically sustainable industry in a low carbon economy.[31]

4.1.2. Small scale photovoltaic generation

A number of Australian states have made substantial changes to the basis on which photovoltaic (PV) generated power is renumerated, particularly in relation to regulated feed-in tariffs that are paid for power sent into the distribution system.

---

[29] Prime Minister of Australia, *Climate Change Framework Announced*, Media Release, 24 February 2011.

[30] Clean Energy Regulator, Guide to Carbon Pricing Price Liability, page 16.

[31] Department of Industry website, <http://www.innovation.gov.au/industry/cleanenergyfuture/Pages/SteelTransformationPlan.aspx>, viewed on 14 January 2014.

For example, the South Australia state parliament terminated the South Australian feed-in tariff program on 1 October 2011.[32] However, households that had applied for the feed-in tariff prior to 1 October were still eligible for the tariff previously applying, while a lower feed-in tariff was offered to other investors as part of a change management scheme.

Similarly, the Queensland government made prospective amendments to its solar bonus scheme by reducing the feed-in tariff for investments in solar powered generators from 10 July 2012. However, investors in solar powered generators prior to 10 July 2012 were still eligible for the original, and substantially higher, feed-in tariff.[33]

The ACT government closed its feed-in tariff scheme from 14 July 2014 and, in so doing, stated that:[34]

> *"In closing the category the Government made an undertaking that households who had entered into formal contracts in good faith up until that time could still access the Scheme so as not to be disadvantaged."*

Each of the amendments set out above were made on a prospective basis so as not adversely to affect existing investors in solar-powered generation. Investors' expectations were therefore upheld, while the objectives of the reforms were achieved.

4.1.3. Network service providers

In December 2012 the Australian Economic Regulator (AER) announced that there would be a change in the calculation of the cost of debt allowance to be incorporated into regulatory price determinations for network service providers.

Under the previous 'on the day' approach, the return on debt allowance for a regulated service provider was established by reference to the prevailing return on debt, measured as close as possible to the start of the regulatory control period. By contrast, the new 'trailing average' approach estimates the return on debt allowance by reference to the average return that would have been required by investors in a benchmark efficient entity had it raised debt over a multi-year period prior to the commencement of the regulatory control period.[35]

The immediate implementation of the 'trailing average' approach may have resulted in unexpected wealth transfers. For example, if the 'on the day' approach was expected to set a cost of debt in the future that was less than the estimate of the 'trailing average' cost of debt expected at the beginning of the next regulatory period, immediate implementation of the trailing average approach would give rise to a windfall loss to the regulated service provider and a commensurate windfall gain to its customers.

---

[32] South Australia Electricity (Miscellaneous) Amendment Bill 2011

[33] Queensland Government Department of Energy and Water Supply website, < http://www.dews.qld.gov.au/energy-water-home/electricity/solar-bonus-scheme/how-scheme-works>, viewed on15 January 2014.

[34] Minister for Health and the Minister for Industrial Relations, *Feed-in Tariff Scheme Closes*, Media Release, 14 July 2011.

[35] AER, *Explanatory Statement Rate of Return Guideline*, December 2013, page 104.

The AER considered the need for a change management arrangement by, in part, focusing on the potential for:

> *"significant and unexpected change in the costs/prices that may have negative effects on confidence in the predictability of the regulatory arrangements."*

The AER concluded that there was a need for a transition to the trailing average basis and stated that:[36]

> *"We consider a transition is necessary to provide a gradual adjustment to the change of approach to the allowed return on debt estimation. This would accommodate any potential discrepancy between the new approach to estimating the return on debt and reasonable expectations consumers, service providers, and investors formed before the rule change."*

In light of these considerations, the AER adopted the "Queensland Treasury Corporation (QTC)" method of transition, whereby there is an annual repricing of a regulated entity's cost of debt allowance, undertaken by reference to a portion of its notional debt requirement.

Under the QTC method, the return on debt allowance in the first regulatory year would be the prevailing rate for that year. In the second regulatory year, the return on debt allowance would be a weighted average sum of the prevailing rates in each of the first and second years, with weights of 0.9 and 0.1 respectively. In the third year, the return on debt allowance would be a weighted sum of the prevailing rates in each of the first, second and third regulatory years, with weights of 0.7, 0.1 and 0.1 respectively.

This pattern is to be continued until, in the tenth and final year of the transition, the return on debt allowance is equal to a weighted sum of the prevailing rates in each of the ten years of the transition, each with a weight of 0.1.[37]

This transition allowed the AER to achieve its objective of switching to a 'trailing average' approach while also meeting participants' reasonable expectations.

4.1.4. Mineral resource rent tax

In July 2011 the Australian government announced the introduction of a mining resource rent tax (MRRT) that placed a 30% levy on the profits of some mining companies from 1 July 2012.

The MRRT applied to investors in both previous and future projects and was a controversial policy, partly on account of its potential effects on sovereign risk. Sovereign risk refers to the possibility that investments will be reduced in value by future changes in government policy.[38] Instability in taxation regimes contributes to sovereign risk, which increases the

---

[36] AER, *Explanatory Statement Draft Rate of Return Guideline*, August 2013, page 123.

[37] AER, *Explanatory Statement Rate of Return Guideline - Appendices*, December 2013, page 131.

[38] Treasury, *Australia's Future Tax System*, December 2009, page 224.

required rate of return for investment and makes Australia a less attractive investment destination for foreign investors.

The Australia Future Tax review, which prompted the then government to consider a resource tax, recognised that:[39]

> *"Depending on transitional arrangements, the transfer of existing projects into a new system may increase perceived sovereign risk in the short to medium term."*

The Australia Future Tax review went on to recommend that the government establish a starting value for the tax base that would effectively operate as a lump-sum transfer to existing mining projects, in order not to distort subsequent production decisions.[40]

Accordingly, the MRRT included a starting tax base allowance to recognise investments in assets relating to investment that existed prior to the announcement of the resource tax reforms on 2 May 2010.[41] The starting base reduced the MRRT liability by allowing a deduction for the depreciation of the value of mining projects existing at 1 May 2010 and certain expenditure incurred between 2 May 2010 and 30 June 2012.[42]

4.2. United States regulatory environment

The United States (US) regulatory environment developed in a fundamentally different manner from that in New Zealand, Australia and the UK. This was primarily because the majority of regulated utilities in the US have always been privately owned companies, rather than publicly owned entities that were later subject to legislative economic regulation. In consequence, the US regulatory framework and regulatory principles have developed and been codified over time through case-law. The principles set out in a number of landmark decisions have subsequently been adopted by both US and international regulators.

The US Supreme Court in the matter *Federal Power Commission v. Hope Natural Gas Co* (1944) (*Hope*) articulated a number of fundamental regulatory principles.[43] The *Hope* decision articulated a now well-known premise that the regulatory process involves the balancing of customer and stockholder interests. The Court stated:[44]

> *"[t]he rate-making process … i.e., the fixing of "just and reasonable" rates, involves a balancing of the investor and the consumer interest."*

---

39 Treasury, *Australia's Future Tax System*, December 2009, page 239.

40 Treasury, *Australia's Future Tax System*, December 2009, page 239.

41 Parliament of the Commonwealth of Australia, *Minerals Resource Rent Tax Bill 2011*, explanatory Memorandum, page 119.

42 Parliament of the Commonwealth of Australia, *Minerals Resource Rent Tax Bill 2011*, explanatory Memorandum, page 119.

43 *Also see Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

44 *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), at 603.

In *Hope* the Court determined that any method of regulation that results in a proper balancing of the interests of customers and stockholders is permissible. Since no single method, formula, or process, however theoretically attractive, will necessarily balance the interests of stakeholders under all circumstances, the *Hope* Court opted for a method of "pragmatic adjustment," enabling regulators to adapt to changing conditions.[45]

To understand the reasoning behind *Hope*, it is necessary to recognise the special nature of property used to serve the public. *Hope* singled out the need and, indeed, requirement for the utility to attract capital and remain financially sound. In recognition of the special role of the property used to serve the public, *Hope* established what has become the current standard for a fair and reasonable financial return:[46]

> *"…the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital."*

We note that the existence and impact of regulatory risk was in 1944 recognised by the Court, in the *Binghamton Bridge* decision of 1865. In that decision the Court recognised that any policy affecting the recovery of prudent costs has an effect on the cost of capital. This process is symmetric in that recovery of prudent costs leads to reasonable costs of capital and disallowance of prudent costs leads to higher costs of capital. The recognition that this bargain is between society and the utility is best captured by the following:[47]

> *"The … [capital needed is]…beyond the ability of individual enterprise, and can only be accomplished through the aid of associated wealth. This will not be risked unless privileges are given and securities furnished in an act of incorporation. The wants of the public are often so imperative that a duty is imposed on the Government to provide for them; and, as experience has proved that a State should not directly attempt to do this, it is necessary to confer on others the faculty of doing what the sovereign power is unwilling to undertake. The legislature, therefore, says to public-spirited citizens: "If you will embark, with your time, money, and skill, in an enterprise which will accommodate the public necessities, we will grant to you, for a limited time period or in perpetuity, privileges that will justify the expenditure of your money, and the employment of your time and skill." Such a grant is a contract, with mutual consideration, and justice and good policy alike require that the protection of the law should be assured to it."*

As one of the proponents of the prudent investment standard of regulation, James Bonbright put considerable thought into the idea of what constitutes the meaning of fairness under the regulatory bargain. As he described the concept:

---

45 *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), at 603.

46 *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), 603.

47 *The Binghamton Bridge,* 70 U.S. (3 Wall.) 51(1865), page 73.

"The meaning of fairness in business transactions is most clearly definable when referring to a moral obligation, which may also be a legal obligation, to avoid deception and live up to previous commitments, expressed or implied. If judged by this test alone, any rule of ratemaking would be fair to investors, whatever its merits or demerits on other grounds, if it conforms to the terms, on the faith of which the investment was originally made—fair no matter how onerous or how profitable these terms may prove to be in light of hindsight. [48]

In sum, the regulatory bargain is designed to create a relational contract between the regulated and the public in order to provide incentives for investment and efficient operations. ***Adding unnecessary regulatory risk to that relationship creates the potential for investors to look elsewhere for investment opportunities or, at a minimum, require a higher expected return to provide the capital necessary to provide service to the public. [Emphasis added]"***

4.3. US electricity industry case studies

In the US, regulators or courts have sought to minimise regulatory risk in a number of cases. This section discusses two major examples of how regulators or courts have eventually addressed the risk. These examples come from the history of the US electricity industry and include:

- stranded costs associated with changes in industry structure: in the 1990s several US states restructured their then-existing vertically integrated electric utilities, generally by requiring or incentivising the divesture of generation assets. This change in government policy had implications for existing and future investment; and
- fuel price risk: fuel for generation stations is generally purchased through commodity markets. This represents a large and volatile cost because the method of cost recovery can either increase or reduce the regulatory risk of a company.

4.3.1. Stranded costs

In the early 1990s the US federal government created a new class of generation providers that were not regulated electric utilities, but rather provided generation service to wholesale customers.[49] This began the era of wholesale electricity sector competition in the United States.[50]

At the retail level, nearly all major investor-owned electricity utilities owned all or a significant portion of their required generation resources. The industry was largely vertically

---

48 Bonbright, James, *Principles of Public Utility Rates,* Columbia University Press, NY. (1961) page 127.

49 *See US Energy Policy Act of 1992.*

50 Wholesale transactions in the United States were common prior to 1992. For example, PJM was organised in the 1920s and the California utilities formed a power pool in the early 1960s. Most of these transactions were limited, however, to economy and emergency exchanges as well as reserve sharing. In addition, in 1978 the Federal government encouraged development of certain wholesale generators, namely cogeneration and renewable resources, through the *Public Utility Regulatory Policies Act (PURPA).* The PURPA wholesale contracts were generally limited to contractual purchases from PURPA qualifying facilities by the local utility.

integrated since these same utilities generally owned the distribution and transmission networks in their government-allocated service territories. A few years later, several states began to pass electricity industry restructuring laws aimed at separating the distribution network from generation.[51]

By the mid-1990s, sixteen states formally restructured their markets.[52] In most cases those states had relatively high generation costs generally related to either historic high cost generation investments or high cost long-term contracts under PURPA.[53] In these jurisdictions, any immediate move to market-based prices would likely have saddled investors with large financial losses equal to the difference between the book value of the assets (ie, the historic depreciated costs expected to be included in rates over time) and the then-current market prices. This difference between book value and market value was termed stranded cost, since those costs were likely to be unrecoverable in a market-based generation environment.

The basic argument in favour of compensating utilities for their stranded costs was that of regulatory risk. The US Congressional Budget Office summarised this argument as follows:

> *"[some]…economists…have argued that if utilities were denied full reimbursement of their stranded costs, investors would view the electricity market as very risky. Consequently, the cost of capital would rise for new investment, thus raising the future cost of electricity."*[54]

Many observers, as the CBO Report notes, provided counter arguments to this claim. However, every jurisdiction that restructured its electricity sector provided stranded cost recovery though the type of costs recovered. The approaches to calculating stranded costs and the amounts varied by jurisdiction.[55]

4.3.2. Fuel price risk

US regulation is a balancing act that is based on the fundamental premise that the results of regulation are reasonable when both owners and customers are treated fairly. This approach itself derives from one simple premise: the total revenue recovered through prices should equal the total costs incurred to provide service.

---

[51] At the same time the federal government pushed for separate operation, though not ownership, of the transmission networks through independent system operators. In the US jurisdiction over electricity sector transactions is roughly split between the federal government (wholesale transmission tariffs and generation) and state governments (local distribution and retail electricity sales).

[52] In most cases this required significant changes to existing laws.

[53] The California Public Utilities Commission Staff noted the existence of a "price-cost gap" as one of the economic factors that drives bypass opportunities. See, for example: Jeffrey Dasovich, William Meyer and Virginia Coe, (1993); California's Electric Services Industry: Perspectives on the Past, Strategies for the Future, A Report to the California Public Utilities Commission, Division of Strategic Planning, CPUC, San Francisco, CA. p. 107 ; and Paul L. Joskow, Comments on Power Struggles: Explaining Deregulatory Reforms in Electricity Markets, Brookings Papers on Economic Activity: Microeconomics, 125-199.

[54] US Congressional Budget Office, Electric Utilities: Deregulation and Stranded Costs, October 1998, page 19.

[55] The US Energy Information Administration provides a summary of state regulatory policies related to restructuring here: http://www.eia.gov/electricity/policies/restructuring/index.html

Moreover, although *Hope* set no one methodology to determine the costs, the majority of US regulatory bodies have gravitated toward using historic depreciated investment costs plus reasonable expenses. As a result, costs are typically measured for a historic test period to provide the inputs to set going-forward 'rates'.

This approach was premised on three underlying assumptions, ie:

- sales growth;
- continuing economies of scale; and
- that management had a great degree of control over most costs.[56]

So long as those assumptions held, investors had a reasonable expectation of recovering their *actual* prudently-incurred costs, even if those costs did not necessarily arise in the context of the historic test period. However, in today's US electricity industry, one or more of those assumptions generally does not hold. For example, utilities that once used long-term, and in some cases regulated, contracts for fuel procurement of coal and natural gas must now purchase those commodities in volatile commodity markets, which reduces the ability of managers to control those costs.[57]

The resulted in a disconnect between the prudent historic costs (ie, those costs allowed in rates or price) and the actual prudent costs of providing service. When rates are set based on historic costs, but large, unpredictable, and uncontrollable costs such as fuel begin to diverge from historic levels, investors no longer have a reasonable expectation of cost recovery.

Even in jurisdictions that have adopted a forecast or forward-looking test period, the volatile nature of commodity markets means that forecasting often still cannot provide proper matching of costs with prices. In response, most regulators in the US adopted a more frequent, outside the test period, price adjustment mechanism to track the actual prudent costs of fuel. This adjustment mechanism, often called a fuel adjustment clause, re-established the reasonable expectation of cost recovery.

The US Federal Power Commission, the predecessor of the current Federal Energy Regulatory Commission, described the problem as follows:

> *"We recognize the need for a fuel adjustment clause. Properly administered fuel clauses can accomplish legitimate public interest objectives. Fuel clauses serve as a cost of service type mechanism to pass through changes in actual, reasonably and prudently incurred costs of fuel (decreases as well as increases), ensure appropriate and timely cash flow to electric utilities by eliminating "regulatory lag", and reduce regulatory expense, administrative process costs and the number of formal rate*

---

56 *See e.g.,* K.A. McDermott, *Cost of Service Regulation in the Investor-Owned Electric Utility Industry: A History of Adaption*, Edison Electric Institute, Washington, DC. June 2012.

57 Moreover commodities such as coal and natural gas are no longer sold in long-term markets.

proceedings. These features of the fuel clause inure to the benefit not only of the public utility but also the customers and taxpaying public."[58]

One of the last remaining jurisdictions without a fuel clause was Utah. Nevertheless, in early 2009, the owner of Utah's largest vertically integrated electric utility, PacifiCorp, filed with the Utah regulator a request to approve a fuel adjustment clause (called an Energy Cost Adjustment Mechanism and later the Energy Balancing Account). In early 2011 the Utah regulator approved a type of fuel adjustment clause for PacifiCorp stating that a properly designed mechanism can bring balance back to the regulatory structure by mitigating the financial harm to the utility and avoid unfair rates for customers that result from relying on forecasts that do not capture the volatility of power costs (including fuel and purchased power).[59]

4.3.3. Conclusion

The development of US regulatory case law recognises the existence of a compact between regulators and investors that provides strong backing for property rights of investors, both as a matter of law and a matter of best practice regulatory and economic policy.

4.4. United Kingdom case studies

4.4.1. Renewables obligation

The British government supports renewable electricity projects in the United Kingdom (UK) through the renewables obligation (RO), which first came into effect in 2002.

Under the RO, accredited renewable electricity generating stations are issued Renewables Obligation Credits (ROCs) on a per-megawatt hour (MWh) basis for the renewable electricity they generate. ROCs can be traded and electricity suppliers must present a sufficient number of ROCs to meet their obligation or pay an equivalent amount into a buy-out fund.[60] An RO order that details the level of obligation for the next year and the level of the buy-out price is issued annually.

When first introduced, each form of renewable energy received the same level of ROCs per MWh of renewable electricity generated, which led to the deployment of established technologies rather than the development of newer, more efficient, technologies. Once it became apparent that the government would not be able to meet its legally binding European Union renewable energy target, in 2007 the government announced a reform of the RO.[61]

---

[58] 40 Fed Reg. 26702, 26705 (1975).

[59] Utah Public Service Commission, Report and Order in Docket No. 09-035-15, March 2, 2011, pp.66-67.

[60] Parliamentary Office of Science and Technology, *Renewable Energy*, October 2001, Postnote Number 164.

[61] Department of Trade & Industry, *Reform of the Renewables Obligation*, May 2007.

The RO was reformed through the introduction of banding, whereby different levels of support were to be provided to different technologies. However, the government avoided increasing regulatory risk by:[62]

> *"... preserving investor confidence by applying changes only to new projects"*

It follows that, by not amending the commitments made to existing investors, the government was able to achieve the objectives associated with the RO reform and avoid an unnecessary increase in regulatory risk.

4.4.2. UK solar feed-in tariffs

The FIT scheme was introduced in the United Kingdom (UK) in April 2011 to encourage small-scale low-carbon electricity generators, eg, solar photovoltaic (PV) generators.

Under the FIT scheme, feed-in tariffs are paid to small-scale generators for the electricity they produce and also for electricity exported into the grid. The Feed-in tariff for solar PV generators was set such that generators would derive an approximate return for a period lasting a maximum of 25 years.

However, the take up of the FIT scheme far exceeded expectations and the cost of installing solar PV decreased substantially following the introduction of the FIT scheme.[63] It follows that the Secretary of State was concerned that solar PV generators would be overcompensated and the FIT budget would be breached,[64] which would limit the funds available to other technologies and future generators.

In October 2011, the Department of Energy and Climate change published a consultation document that proposed that the tariff rate to be paid in respect of eligible solar PV on or after 12 December 2011, should be reduced from 1 April 2012.[65]

The FIT scheme provides that the tariff rate is fixed for the 25 year maximum period with reference to the year in which the installation becomes eligible.[66] For solar PV that became eligible during the period from 12 December 2011 to 31 March 2012, the fixed tariff rate is the higher rate initially set by the government, ie, in the year ended 31 March 2012. However, the proposal was to reduce the tariff rates for solar PV that became eligible from 12 December 2011 to 31 March 2012, effective 1 April 2012.

---

62 Department of Trade & Industry, *The Energy Challenge Energy Review Report 2006*, July 2006, paragraph 5.38.

63 Department of Energy & Climate Change, *Feed-in tariffs scheme: consultation on Comprehensive Review Phase 1 – tariffs for solar PV*, October 2011, paragraph 3.

64 Department of Energy & Climate Change, *Feed-in tariffs scheme: consultation on Comprehensive Review Phase 1 – tariffs for solar PV*, October 2011, paragraph 28.

65 Department of Energy & Climate Change, *Feed-in tariffs scheme: consultation on Comprehensive Review Phase 1 – tariffs for solar PV*, October 2011, paragraph 6.

66 *The Secretary of State for Energy and Climate Change v Friends of the Earth and Others* (2012), EWCA Civ 28, paragraph 39.

Proceedings were launched against the Secretary of State due to concerns that the Secretary of State had modified the system that investors in solar PV considered to be established. A hearing took place and, on 21 December 2011, Justice Mitting ruled in the High Court that the application of the reduced tariff to solar PV installations that became eligible between 12 December 2011 and 1 April 2012 was unlawful.[67] The basis for Justice Mitting's decision was that the application of lower tariffs to solar PV installations before 1 April 2012 was not calculated to further the statutory purpose of the Energy Act 2008 and that a modification that adversely affected investors that were eligible before 1 April 2012 was *ultra vires* the Secretary of State's powers.

Justice Mitting's decision was appealed and, then, upheld in the Court of Appeal on 25 January 2012. The appeal turned on whether it was:[68]

> *"… within the power conferred on the Secretary of State by the Energy Act 2008 to make a modification which reduced the tariff in respect of installations becoming eligible for payment prior to the coming into force of the modification [1 April 2012]."*

Lord Justice Moses ruled in the Court of Appeal that there was no power in section 41 of the Energy Act 2008 to introduce a modification that reduced a rate fixed by reference to an installation becoming eligible before the modification came into effect on 1 April 2012 and that, to do so, would take away an existing entitlement without statutory authority.[69]

4.4.3. Conclusion

The British government and its courts have also recognised the role of preserving investor confidence. They have done so by including change management arrangements to preserve the reasonable expectations of existing investors when making amendments that would otherwise alter the financial arrangements determining the remuneration of investors who are responding to price signals.

---

67 *R (Friends of the Earth and others) v Secretary of State for Energy and Climate Change* (2011) All ER (D) 190 (Dec).

68 *The Secretary of State for Energy and Climate Change v Friends of the Earth and Others* (2012), EWCA Civ 28, paragraph 14.

69 *The Secretary of State for Energy and Climate Change v Friends of the Earth and Others* (2012), EWCA Civ 28, paragraph 52.

5. Conclusion

An unanticipated change in the RET scheme that significantly reduces or removes RET payments would result in an unforeseen wealth transfer from existing investors to other industry participants and, consequently, an increase in the level of perceived uncertainty and unpredictability in government policies and the regulatory regimes that enact them.

An increase in perceived sovereign and regulatory risk will result in investors demanding a higher rate of return to invest regulated industries, which will:

- increase the cost of providing services;
- increase prices;
- result in under-investment; and
- dampen the effectiveness of price signals.

In our opinion, amending payments under the RET scheme in a way that increases regulatory risk in the electricity industry will not promote the efficient operation of, or reliable supply by, the electricity industry and will ultimately not benefit consumers. We conclude that, taken by itself, a reform that would remove or reduce RET payments for existing renewable electricity generators would be unlikely to be consistent with this overarching objective of electricity regulation.

Furthermore, to the extent that investors in other industries consider the government's decisions in the electricity industry to be a signal of policy commitment more generally, there will likely be unintended consequences for the cost of capital, prices and investment decisions in other regulated industries.

If the government were to conclude that the existing RET scheme should be amended, it will be critical to take account of the financial interests of existing investors in renewable electricity generation. In order to minimise the adverse effect of increased sovereign and regulatory risk, the government should ensure that existing investors are sufficiently compensated for departures from the returns they would reasonably have been anticipated under the existing, long-standing regulatory arrangements. The cost of any such compensation should also be taken into account in the analysis underpinning any decision to amend the scheme.

Report qualifications/assumptions and limiting conditions

This report is for the exclusive use of the NERA Economic Consulting client named herein. There are no third party beneficiaries with respect to this report, and NERA Economic Consulting does not accept any liability to any third party.

Information furnished by others, upon which all or portions of this report are based, is believed to be reliable but has not been independently verified, unless otherwise expressly indicated. Public information and industry and statistical data are from sources we deem to be reliable; however, we make no representation as to the accuracy or completeness of such information. The findings contained in this report may contain predictions based on current data and historical trends. Any such predictions are subject to inherent risks and uncertainties. NERA Economic Consulting accepts no responsibility for actual results or future events.

The opinions expressed in this report are valid only for the purpose stated herein and as of the date of this report. No obligation is assumed to revise this report to reflect changes, events or conditions, which occur subsequent to the date hereof.

All decisions in connection with the implementation or use of advice or recommendations contained in this report are the sole responsibility of the client. This report does not represent investment advice nor does it provide an opinion regarding the fairness of any transaction to any and all parties.

NERA Economic Consulting
Darling Park Tower 3
201 Sussex Street
Sydney NSW 2000
Tel: 61 2 8864 6500 Fax: 61 2 8864 6549
www.nera.com