NERA
ECONOMIC CONSULTING

Regulatory Change Management

A report for Trustpower

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Executive Summary

This report has been prepared by NERA Economic Consulting (NERA) at the request of Trustpower Limited (Trustpower) for public submission to the Electricity Authority (the Authority). Its subject is how best to manage regulatory change in regard to the Authority's preliminary view that the avoided cost of transmission (ACOT) payments to distributed generators should be amended.

Managing regulatory change with regard to regulatory best practice will ensure that any reform to ACOT payments does not compromise the Authority's statutory objective of:

> *"promoting competition in, reliable supply by, and the efficient operation of the electricity industry for the long term benefit of consumers."*

Review of ACOT payments

The Authority is currently undertaking a review of the transmission pricing methodology (TPM) and, as part of this review, released a working paper that assessed the extent to which ACOT payments influence transmission and distribution investment, and whether ACOT payments provide other benefits.[1]

The ACOT working paper concluded that the current ACOT payment system does not promote efficient outcomes and, consequently, is inconsistent with the Authority's statutory objective.[2] The Authority's preliminary view is therefore that Schedule 6.4 of the Electricity Participation Code 2010 (the Code), which sets out the ACOT payments, should be reviewed.[3]

We understand the Authority may undertake such a review, which could be progressed in parallel to the current TPM review. However, the Authority is subject to different requirements when making changes to ACOT payments, relative to changes to the TPM. In light of the different requirements governing any change, in our opinion the Authority should use its ability to amend ACOT payments with care and be guided by regulatory best-practice.

Regulatory risk

Regulatory arrangements are critical to determining the basis for cost recovery and the risk of not recovering the cost of an investment. Changes in regulatory rules that substantially affect the basis of, and prospects for, investor cost recovery need to be handled with a great deal of care and sensitivity in relation to the expectations of existing investors.

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1 Electricity Authority, *Transmission Pricing Methodology: Avoided Cost of transmission (ACOT) payments for distributed generation*, 19 November 2013, page ii.

2 Electricity Authority, *Transmission Pricing Methodology: Avoided Cost of transmission (ACOT) payments for distributed generation*, 19 November 2013, page 43.

3 Electricity Authority, *Transmission Pricing Methodology: Avoided Cost of transmission (ACOT) payments for distributed generation*, 19 November 2013, page 43.

Regulatory authorities with a track-record of making substantial and/or ex-post adjustments that affect investors' reasonably anticipated returns will increase the level of uncertainty and predictability in the regulatory environment and, in so doing, substantially increase the level of regulatory risk.

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

- increase the cost of operation in the electricity industry;
- increase electricity prices;
- result in under-investment; and
- dampen the effectiveness of price signals.

It follows that it is important to consider the extent to which an amendment to ACOT payments will increase the level of regulatory risk, ie, the cost of capital, in the New Zealand electricity industry.

Effect on existing investors in distributed generation

An amendment to Schedule 6.4 of the Code that reduces or removes ACOT payments would have the effect of reducing the return on investments in distributed generation. Such a change would inevitably reduce the incentive for new distributed generation and, in the first instance, reduce the incentive on existing distributed generators to produce power during periods of peak demand. The effect on requirements for transmission and distribution investment could be material.

The amendment would also result in a substantial transfer of wealth from existing investors in distributed generators to other industry participants, and to increase the level of regulatory risk perceived in relation to the New Zealand electricity sector.

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

Change management measures

The adverse effects of regulatory 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 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 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 regulatory change that significantly reduces or removes ACOT payments will result in an unforeseen wealth transfer from existing investors to other industry participants and, consequently, increase the level of uncertainty and predictability in the regulatory regime.

The consequences of an increase in regulatory risk are that investors will demand a higher rate of return to invest in the New Zealand electricity industry, which will:

- increase the cost of operation in the electricity industry;
- increase electricity prices;
- result in under-investment; and
- dampen the effectiveness of price signals.

It follows that, in our opinion, the unanticipated reduction or removal of ACOT payments alone is not consistent with the Authority's statutory objective of promoting competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

Rather, incorporating change management arrangements that compensate existing investors in distributed generation would allow the Authority to achieve any long-term efficiency benefits associated with amending ACOT payments and, at the same time, avoid the adverse effects of increasing regulatory risk.

In our opinion, a regulatory reform that reduces or removes ACOT payments will only be consistent with the Authority's statutory objective if it includes change management arrangements that compensate existing investors in distributed generation for departures from the returns they would reasonably have anticipated under the existing, long standing regulatory arrangements.

1. Introduction

This report has been prepared by NERA Economic Consulting (NERA) at the request of Trustpower Limited (Trustpower) for public submission to the Electricity Authority (the Authority). Its subject is how best to manage regulatory change in regard to the Authority's preliminary view that the avoided cost of transmission payments to distributed generators should be amended.

The Authority is currently undertaking a review of the transmission pricing methodology (TPM) and, as part of this process, has released a working paper (the ACOT working paper) assessing the extent to which avoided cost of transmission payments to distributed generators influence transmission and distribution investment, and whether ACOT payments provide other benefits.

The ACOT working paper concluded that ACOT payments, in their current form, do not promote efficient outcomes and, consequently, are inconsistent with the Authority's statutory objective.

It is in this context that we have been asked to assess the effects of reducing or removing ACOT payments on existing investors in distributed generation and, in light of those effects, to set out how the Authority should implement such changes to the regulatory framework, having regard to regulatory best-practice.

Our report is structured as follows:

- section two describes the relevant background;
- section three discusses economic regulation and the effects of amending ACOT payments on existing distributed generators;
- section four sets out examples in which overseas regulatory authorities - in Australia, the United States and the United Kingdom - have implemented reforms that use change management arrangements to mitigate regulatory risk; and
- section five concludes.

2. Background

This section sets out the background and context of this report with reference to the Authority, electricity industry legislation, the Authority's current review of the TPM and the ACOT working paper.

2.1. The Electricity Authority

The Authority is an independent crown entity that is responsible for the efficient operation of the New Zealand electricity market.

2.1.1. Statutory objective

The Authority is required to have regard to government policy statements but must pursue the statutory objective set for it in the Electricity Industry Act 2010, which states that: [4]

> *"The objective of the Authority is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers."*

The Authority has interpreted this statutory objective to mean that it should discharge its duties:[5]

- to facilitate and encourage competition in the markets for electricity with reference to the long-term opportunities and incentives for efficient entry, exit, investment and innovation of those markets;
- to encourage industry participants to develop and operate the electricity system to manage security and reliability in ways that minimise total costs while also being robust to the occurrence of adverse events, ie, outages; and
- by performing its function in a way that increases overall efficiency, with particular regard to efficient incentives for investment and innovation.

2.1.2. Other objectives

The Authority describes its mission as being to achieve its statutory objective and, in so doing, have the NZ electricity market regarded as one of the world's most efficient and innovative, with characteristics that include:

- the electricity market having a high level of credibility – both nationally and internationally – giving stakeholders confidence;[6] and
- the market arrangements supporting innovation and investment.[7]

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[4] Electricity Industry Act 2010, section 15.

[5] Electricity Authority, *Interpretation of the Authority's Statutory Objective*, 14 February 2011, parts A.30, A.48 and A.66.

[6] The Electricity Authority website, <https://www.ea.govt.nz/about-us/structure/vision-values-mission/> viewed on 8 January 2014.

In addition, the Authority states its aim as being a world-class electricity regulator, delivering long-term benefits for consumers and providing a positive contribution to the New Zealand economy.[8]

2.2. Distributed generation

Along with virtually all developed economies, the New Zealand electricity sector is characterised by a relatively small number of large power stations that transport electrical energy through high voltage transmission lines, and then on to customers through a local distribution network. Augmenting these large power stations are small scale distributed generators that are embedded in the local distribution network. Further, distributed generation is injected into the transmission grid when distributed generators generate more electricity than is required on their local network.

Electricity from distributed generators can be produced using:

- wind turbines;
- solar panels;
- hydro turbines;
- geothermal heat;
- bio-energy; or
- diesel or gas turbines.

2.3. The Electricity Participation Code

The Electricity Participation code sets out the responsibilities of the Authority and industry participants. The Authority is responsible for maintaining the Code and for ensuring that participants comply with the regulations contained therein.

2.3.1. Transmission pricing methodology

The current transmission pricing methodology (TPM) is set out in schedule 12.4 of the Electricity Participation Code 2010 (the Code), which defines the method by which transmission charges are calculated.

The purpose of the TPM is to ensure that the full economic cost of the services[9] provided by Transpower New Zealand Limited[10] (Transpower) are allocated to designated transmission

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7 The Electricity Authority website, <https://www.ea.govt.nz/about-us/structure/vision-values-mission/> viewed on 8 January 2014.

8 The Electricity Authority website, <https://www.ea.govt.nz/about-us/structure/vision-values-mission/> viewed on 8 January 2014.

9 Except those assets and services subject to investment contracts under clauses 12.70 and 12.71 of the Code and existing new investment contracts and certain other contracts of the kind referred to in clause 12.95 of the Code.

10 Transpower is a state owned enterprise responsible for electric power transmission.

customers such that Transpower recovers its prudent costs.[11] In developing the TPM, the Authority must assess the methodology against its statutory objective of promoting competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

The Authority may only review approved TPM Guidelines if it considers that there has been a *material change in circumstances*[12] and, if so, the Authority must then undertake the consultative process set out below.[13]

Changing the TPM involves a consultative process whereby the Authority must publish an issues paper on the process for development and approval of the TPM Guidelines to be followed by Transpower in preparing a methodology for allocating Transpower's revenue to designated transmission customers.[14] Further, the Authority is required to request, review and consider submissions on the issues paper. The Authority must then publish the process and Guidelines for the TPM after it has considered all the submissions on the issues paper.

The Authority may only propose a change to the TPM Guidelines if there has been a material change in circumstances. This is a safeguard against frequent changes to the TPM. However, Transpower may propose a variation to the TPM at any time, provided 12 months has elapsed since the date on which the Authority approved TPM Guidelines. The requirement for Transpower to wait 12 months since the date on which the Authority approved TPM Guidelines is to enable and facilitate the implementation of those Guidelines.

2.3.2. Remuneration for distributed generation

As well as being paid for the electricity they produce, larger distributed generators in NZ are also remunerated according to the avoided cost of transmission (ACOT), in accordance with the pricing principles set out in Schedule 6.4 of the Code.[15]

The Code requires distributors to calculate the incremental cost of connecting the distributed generator less the transmission and distribution costs that it expects to be able to avoid as a result of the connection of the distributed generator.[16] Where the resulting amount is negative, the distributed generator is deemed to be providing network support to the distributor and may invoice the distributor for this service.[17] Costs that cannot be calculated must be estimated by reference to reasonable estimates of how a distributor's capital investment decisions and operating costs would differ in the future with, and without, the distributed generator.

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11 Electricity Industry Participation Code, Part 12, clause 12.77.

12 Electricity Industry Participation Code 2010, clause 12.86

13 Electricity Industry Participation Code 2010, clause 12.87.

14 Electricity Industry Participation Code 2010, clause 12.81.

15 Electricity Industry Participation Code 2010, schedule 6.4.

16 Electricity Industry Participation Code 2010, schedule 6.4, clause 2(a).

17 Electricity Industry Participation Code 2010, schedule 6.4, clause 2(e).

Although first legislated in the 2007 in the Electricity Governance (Connection of Distributed Generation) Regulations 2007 (the 2007 Regulations),[18] remunerating distributed generators on the basis of reduced transmission charges, ie, by reference to the ACOT principle, has been in place for decades and so is a longstanding element of the regulated environment for electricity in NZ. Further, signals to reduce peak demand via distributed generation date back to the 1950s, when the bulk supply tariff was levied on local power boards on the basis of peak demand.

More recently, the 2007 Regulations,[19] were revoked and replaced on 1 November 2010 by the Electricity Industry Act 2010 (the Act).[20] However, despite the revocation of the 2007 Regulations, the New Zealand government recommitted at that time to an ACOT basis for remunerating distributed generators in the Code.[21]

2.4. Review of the transmission pricing methodology

In early 2011 the Authority decided to continue the TPM review started by its predecessor, the Electricity Commission, by setting up an advisory group to make recommendations to the Authority. However, the advisory group could not reach a consensus and, in October 2012, the Authority proposed a new TPM, and published its analysis and draft TPM guidelines in an issues paper (the first issues paper).[22]

Following the publication of the first issues paper, the Authority decided to advance the transmission pricing methodology review by developing a second issues paper, which is scheduled to be made available in the second half of 2014. In the interim, the Authority is developing and considering selected aspects of the TPM proposal in a series of working papers, which will form inputs to the second issues paper.

2.5. The ACOT working paper

Following feedback from distributed generators on the first issues paper, the Authority released a working paper in November 2013 that assessed the extent to which ACOT payments influence transmission and distribution investment, and whether ACOT payments provide other benefits.[23]

The purpose of this paper was to improve the Authority's understanding of the efficiency implications associated with a change to ACOT payments.

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18 Electricity Governance (Connection of Distributed Generation) Regulations 2007, 30 August 2007, schedule 4.

19 Electricity Governance (Connection of Distributed Generation) Regulations 2007, 30 August 2007, schedule 4.

20 Electricity Industry Act 2010, section 166.

21 Electricity Industry Participation Code 2010, schedule 6.4.

22 Electricity Authority, *Transmission Pricing Methodology: Issues and Proposal. Consultation Paper*, 10 October 2012.

23 Electricity Authority, *Transmission Pricing Methodology: Avoided Cost of transmission (ACOT) payments for distributed generation*, 19 November 2013, page ii.

2.5.1. Principal findings of the ACOT working paper

The ACOT working paper highlights that a convention has arisen in recent years whereby ACOT payments are calculated according to the Transpower interconnection charge avoided by distributors, rather than the economic cost of transmission avoided. The working paper concludes that the current ACOT payment system does not promote efficient outcomes and, consequently, is inconsistent with its statutory objective because:[24]

- the majority of ACOT payments are designed to avoid Transpower's transmission *charges* rather than to reduce future operating or capital *costs*;
- customers are unlikely to see any reduction in prices since the cost of ACOT payments are recouped in full from them, while there is also evidence that ACOT payments themselves place a cost on customers;
- there is little effective locational signalling for either distributed generation or transmission investment, since ACOT payments are a uniform rate across much of the country;
- uneconomic projects may be developed, since ACOT payments provide a financial advantage in favour of distributed generation over grid connection; and
- there is evidence that distributed generation places additional costs on the transmission system, not fewer costs.

In light of these findings, the Authority's preliminary view is that Schedule 6.4 of the Code, which sets out the ACOT payments, should be reviewed to ensure that ACOT payments compensate distributed generators for the benefits they provide through avoided economic costs, rather than the transmission charges avoided by the distributor.[25]

The Authority notes that, should it decide to undertake such a review, it could be progressed in parallel to the current TPM review.

2.5.2. Statutory requirements for amending ACOT payments

The Authority is subject to different requirements when making ordinary changes to the Code – such as a change to the pricing principles contained in Schedule 6.4 – relative to the statutory requirements for changes to the TPM, as set out in section 2.3.1.

In particular, there are no limits on how often variations to the Code may be made. Further, the Authority does not have to consider whether or not there has been a *material change in circumstances*.

[24] Electricity Authority, *Transmission Pricing Methodology: Avoided Cost of transmission (ACOT) payments for distributed generation*, 19 November 2013, page 43.

[25] Electricity Authority, *Transmission Pricing Methodology: Avoided Cost of transmission (ACOT) payments for distributed generation*, 19 November 2013, page 43.

Instead, any amendments to the Code must be necessary or desirable to promote any or all of the following:[26]

- competition in the electricity industry;
- the reliable supply of electricity to consumers;
- the efficient operation of the electricity industry;
- the performance by the Authority of its functions; or
- any other matter specifically referred to in this Act as a matter for inclusion in the Code.

The amendments must also comply with the Authority's statutory objective of promoting competition in, reliable supply by, and the efficient operation of the electricity industry for the long-term benefit of consumers.

The Authority is required to publish principles to which it and its advisory groups must adhere when considering Code amendment matters – these principles are set out in Appendix A. The purpose of the Code amendment principles is to provide industry participants with:[27]

> *"… greater certainty and predictability about decision-making on likely amendments to the Code, to maximise investor certainty."*

2.5.2.1. Process for amending ACOT payments

Before amending the Code, the Authority must publish, publicise and consult on a regulatory statement that includes:[28]

- a statement of the objectives of the proposed amendment;
- an evaluation of the costs and benefits of the proposed amendment; and
- an evaluation of alternative means of achieving the objectives of the proposed amendment.

The Electricity Authority usually allocates six weeks for the consultation process.[29]

2.5.2.2. Summary

At the end of the consultation period, ie, 6 weeks after publishing a regulatory statement, it is possible that the proposed amendments to schedule 6.4 may be implemented. Depending on the scope of the amendments, the basis on which a number of distributed generators are remunerated may change substantially.

In our opinion, the Authority's ability to change the Code in a manner that may have significant distributional effects on industry participants, is a far-reaching power. It follows

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[26] The Electricity Participation Act, section 32(1).

[27] Electricity Authority, Consultative Charter, 19 December 2010, paragraph 2.2.

[28] The Electricity Participation Act, section 39(2).

[29] Electricity Authority, Consultation Charter, 19 December 2012, paragraph 2.6.

that this power should be used with care and be guided by its own commitment to regulatory best-practice.

2.6. Context for this report

It is in the context set out above that this report considers the effects of reducing or removing ACOT payments on existing investors in distributed generation, and the consequences of such changes for regulatory risk. Our report also describes how the Authority could mitigate any increase in regulatory risk, having regard to regulatory best practice.

3. Economic Regulation and the Prospects for Cost Recovery

This section discusses the economic regulation of electricity, 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 degree of regulatory risk experienced by them.

We conclude by describing the relevance of regulatory risk to the Authority's preliminary view set out in the ACOT working paper and, in so doing, highlight the need for change management measures in the event that ACOT payments are to be reduced or removed.

3.1. The economic regulation of electricity

Electricity markets are characterised by the significant involvement of economic 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 then compensated under various forms of wholesale market design;
- the determination of which market participants (primarily, either 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 regulatory 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 regulatory rules in determining the expected remuneration of electricity sector investment decisions, best practice regulation has evolved so as to establish a number of core principles for taking account of the interests of investors in both making and amending rules that affect the returns to invested capital. 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
- regulatory risk – the regulator should generally seek to maximise the degree of certainty and predictability associated with future regulatory decisions.

3.1.1. Cost recovery

The principle of cost recovery is consistent with the Authority's statutory objective of promoting competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.[30]

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[30] Electricity Industry Act 2010, section 15.

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.

3.1.2. Regulatory risk

Regulatory arrangements are critical to determining the basis for cost recovery and the risk of not recovering the cost of an investment. Changes in regulatory rules that substantially affect the basis of, and prospects for, investor cost recovery need to be handled with a great deal of care and sensitivity in relation to the expectations of existing investors.

To the extent that such changes are unexpected, they will increase the regulatory risk associated with a regulatory framework. Regulatory risk increases the prospect of investors' expectations as to the return on or return of capital for a particular project not being met, and so increases a regulated firm's cost of providing capital. Such risks arise as a consequence of:

- 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.

The need to ensure that changes in regulatory arrangements minimise the perception of risks arising is a core principle of best practice economic regulation. Section 4 of this report outlines a numerous examples of regulators (or government bodies) taking decisions that involve arrangements specifically designed to reduce the risk of unanticipated change, thereby acting to minimise 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:[31]

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

> *"… 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.[32] 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:[33]

- 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 regulatory risk and uncertainty associated with the returns to capital. Investing in infrastructure involves substantial upfront investments and uncertain future revenues.

Regulatory authorities with a track-record of making substantial and/or ex-post adjustments that affect investors' returns will increase the level of uncertainty and predictability in the regulatory environment and, in so doing, substantially increase the level of regulatory risk.

An increase in regulatory uncertainty correspondingly raises the level of risk perceived by investors. Therefore, the cost of capital in the industry increases because investors require a higher rate of return to compensate them for the increased level of risk borne.

This, in turn, affects the entry decisions of potential investors, since capital investment in the electricity sector 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 price signals. Price signals 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

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

33 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 generally 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 ACOT payments

The Authority's ACOT working paper concluded that section 6.4 of the Code should be reviewed, because ACOT payments are not promoting efficient outcomes. It is therefore important to take into account the extent to which any amendment to or the removal of ACOT payments may result in wealth transfers for existing industry participants.

An amendment to Schedule 6.4 of the Code that reduces or removes ACOT payments would have the effect of reducing the return on investments in distributed generation. Such a change would inevitably reduce the incentive for new distributed generation and, in the first instance, reduce the incentive for existing distributed generators to produce power during periods of peak demand. The effect on requirements for transmission and distribution investment could be material.

The amendment would also result in a substantial transfer of wealth from existing investors in distributed generators to other industry participants.

A consequence of reduced or eliminated ACOT payments having no positive effect on the behaviour of existing distributed generators is that any such ex post wealth transfer would have no discernible efficiency benefits. Instead, such an adjustment would simply increase the level of regulatory risk perceived in relation to the New Zealand electricity sector.

3.2.1. Consistency with the Electricity Authority's objectives

An increase in regulatory risk will increase the cost of capital in the electricity industry, thereby:

- increasing the cost of providing electricity services;
- resulting in under-investment; and
- dampening the effect of 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.

The Authority has previously recognised the effect of ex post wealth transfers – such as those arising from changes in the nature of the reduction or removal of ACOT payments for existing distributed generators – on investment and, ultimately, the welfare of consumers, when it stated that:[34]

> *"… ex post transfers of wealth… in the case of transfers to consumers, is likely to have an undesirable chilling effect on the willingness of parties to invest. This is definitely not a long-term benefit to consumers."*

In our opinion, amending ACOT payments to existing distributed generators 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 ACOT payments for existing distributed generators is unlikely to be consistent with the Authority's statutory objective.

This is not to say that the Authority should be discouraged from a process that potentially seeks to review and amend the existing ACOT arrangements. Rather, the Authority may still achieve the long-term objectives of the ACOT payment reforms by implementing change management measures that shield the financial interests of existing investors in distributed generators. The following chapter sets out examples in which, faced with similar circumstances, best-practice international regulatory authorities have developed and implemented change management measures.

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[34] Electricity Authority, *The Economics of Electricity*, 4 June 2013, paragraph 43.

4. Change Management Arrangements 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.[35]

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.[36]

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.[37]

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.

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

36 Clean Energy Regulator, Guide to Carbon Pricing Price Liability, page 16.

37 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.[38] 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.[39]

The ACT government closed its feed-in tariff scheme from 14 July 2014 and, in so doing, stated that:[40]

> *"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 regulated a 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.[41]

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.

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38 South Australia Electricity (Miscellaneous) Amendment Bill 2011

39 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.

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

41 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:[42]

> *"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.[43]

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.[44] Instability in taxation regimes contributes to sovereign risk, which increases the required rate of return for investment and makes Australia a less attractive investment destination for foreign investors.

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

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

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

The Australia Future Tax review, which prompted the then government to consider a resource tax, recognised that:[45]

> *"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.[46]

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.[47] 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.[48]

4.2. United States regulatory environment

The United States (US) regulatory environment developed in a fundamentally different manner from that in New Zealand, Australian 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.[49] The *Hope* decision articulated a now well-known premise that the regulatory process involves the balancing of customer and stockholder interests. The Court stated:[50]

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

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

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

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

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

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

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

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

stakeholders under all circumstances, the *Hope* Court opted for a method of "pragmatic adjustment," enabling regulators to adapt to changing conditions.[51]

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:[52]

> *"…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:[53]

> *"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:

> *"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*

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

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

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

> *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.* [54]
>
> *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.[55] This began the era of wholesale electricity sector competition in the United States.[56]

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 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.[57]

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

[55] *See US Energy Policy Act of 1992.*

[56] 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.

[57] 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

By the mid-1990s, sixteen states formally restructured their markets.[58] 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.[59] 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."*[60]

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.[61]

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.

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:

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split between the federal government (wholesale transmission tariffs and generation) and state governments (local distribution and retail electricity sales).

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

[59] 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.

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

[61] 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

- sales growth;
- continuing economies of scale; and
- that management had a great degree of control over most costs.[62]

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.[63]

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 proceedings. These features of the fuel clause inure to the benefit not only of the public utility but also the customers and taxpaying public."*[64]

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

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62 *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.

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

64 40 Fed Reg. 26702, 26705 (1975).

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).[65]

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.[66] 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.[67]

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:[68]

> *"… 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.

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

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

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

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

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.[69] It follows that the Secretary of State was concerned that solar PV generators would be overcompensated and the FIT budget would be breached,[70] 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.[71]

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.[72] 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.

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.[73] 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.

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

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

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

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

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

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:[74]

> *"… 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.[75]

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.

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

[75] *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 regulatory change that reduces or removes ACOT payments will result in a wealth transfer from existing investors to other industry participants and, consequently, will increase the level of uncertainty and predictability in the regulatory regime, ie, regulatory risk.

An increase in regulatory risk will increase the cost of capital in the New Zealand electricity industry, which will:

- increase the cost of operation in the electricity industry;
- increase electricity prices;
- result in under-investment; and
- dampen the effectiveness of current and future price signals.

It follows that, in our opinion the unanticipated reduction or removal of ACOT payments alone is not consistent with the Authority's statutory objective of promoting competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

Rather, implementing change management arrangements that compensate existing investors in distributed generation for expectations of returns reasonably held by them would allow the Authority to achieve any efficiency objectives associated with amending ACOT payments and, at the same time, avoid the adverse effects of increasing regulatory risk.

In our opinion, a regulatory reform that reduces or removes ACOT payments will only be consistent with the Authority's statutory objective if it includes change management arrangements to compensate existing investors in distributed generation for departures from the returns they would reasonably have anticipated under the existing, long standing regulatory arrangements.

Appendix A. Code Amendment Principles

When considering amendments to the Code, the Authority and its advisory groups will have regard to the following Code amendment principles to the extent that the Authority and its advisory groups consider that they are applicable in each case:[76]

Principle 1 – Lawful: The Authority and its advisory groups will only consider amendments to the Code that are lawful and that are consistent with the Act (and therefore consistent with the Authority's statutory objective and its obligations under the Act).

Principle 2 – Provides Clearly Identified Efficiency Gain or Market or Regulatory Failure: Within the legal framework specified in Principle 1, the Authority and its advisory groups will only consider using the Code to regulate market activity when:

- it can be demonstrated that amendments to the Code will improve the efficiency1 of the electricity industry for the long-term benefit of consumers;
- market failure is clearly identified, such as may arise from market power, externalities, asymmetric information and prohibitive transaction costs; or
- a problem is created by the existing Code, which either requires an amendment to the Code, or an amendment to the way in which the Code is applied.

Principle 3 – Net Benefits are Quantified: When considering possible amendments to the Code, the Authority and its advisory groups will ensure disclosure of key assumptions and sensitivities, and use quantitative cost-benefit analysis to assess long-term net benefits for consumers, although the Authority recognises that quantitative analysis will not always be possible. This approach means that competition and reliability are assessed solely in regard to their economic efficiency effects. Particular care will be taken to include dynamic efficiency effects in the assessment, and the assessment will include sensitivity analysis when there is uncertainty about key parameters.

Tie-breaker 1: Principles 4 – 8 apply when the cost-benefit analysis of Code amendment options demonstrates a positive net benefit relative to the counterfactual, but is inconclusive about which is the best option. The Authority will weight these principles in accordance with their relevance and significance for each proposal.

Principle 4 – Preference for Small-Scale 'Trial and Error' Options: When considering possible amendments to the Code, the Authority and its advisory groups will give preference to options that are initially small-scale, and flexible, scalable and relatively easily reversible with relatively low value transfers associated with doing so. In these circumstances the Authority will monitor the effects of the implemented option and reject, refine or expand that solution in accordance with the results from the monitoring.

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76 Electricity Authority, Consultation Charter, 19 December 2012, paragraph 2.5.

Principle 5 – Preference for Greater Competition: The Authority and its advisory groups will give preference to Code amendment options that have larger pro-competition effects, because greater competition is *likely* to be positive for economic efficiency and reliability of supply.

Principle 6 – Preference for Market Solutions: The Authority and its advisory groups will give preference to Code amendment options that directly address the source of the market failure identified under Principle 2, so as to facilitate efficient market arrangements. The Authority and its advisory groups will discount options that subdue or displace efficient market structures.

Principle 7 – Preference for flexibility to allow innovation: The Authority and its advisory groups will give preference to Code amendment options that provide industry participants with greater freedom and lower costs to adapt to the Code amendment as they see fit, unless more restrictive options are justified on the grounds of non-rivalry and/or non-excludability conditions.[2] In the case where both conditions hold perfectly it is generally efficient to adopt a 'one size fits all' approach, such as uniform standards. Where these conditions do not hold it may be more efficient to utilise flexible mechanisms, such as incentives.

Principle 8 – Preference for Non-Prescriptive Options: Wherever practicable, when the Authority and its advisory groups are considering standards, they will give preference to Code amendment options that specify the outcomes required of industry participants rather than prescribe what they must do and how they must do it. That is, outcome standards are preferred to input standards, wherever possible.

Tie-breaker 2: Principle 9 applies when the cost-benefit analysis of Code amendment options is inconclusive that a Code amendment would yield net benefits and there are no options that are small-scale, flexible, scalable and relatively easily reversible.

Principle 9 – Risk Reporting: The Authority will publish a report:

- that assesses the risks of making and not making the Code amendment, taking into account Principles 5 – 8, and factoring in the option value associated with waiting longer before intervening; and
- that identifies and assesses non-Code methods for mitigating or addressing the problem.

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