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Review of Energy Market Frameworks in light of Climate Change Policies

Comment on Final Report

The Foundation's and the Centre's involvement

The Foundation and the Centre are partners in a project entitled:

Attaining optimal carbon abatement rules through consumer advocacy: Learning from European Experience on the Regulation of Energy

The project is aimed at producing advocacy research papers, as well as research support for consumer group advocacy, in relation to the various current consultation processes relating to the development and implementation of climate change policies for the Australian energy markets.

While the project involves consultation with consumer groups any opinions, conclusions and recommendations in this paper and future papers are to be attributed only to the project team members and not to any organisation consulted. Moreover, project team members recognise that certain organisations have special knowledge, particularly in the field of the needs and experiences of classes of consumers in Australia, especially those on fixed incomes and otherwise disadvantaged. Such organisations may well have their own developed views on appropriate solutions for the protection and advancement of the interests of particular classes of consumers.

This project was funded by the Consumer Advocacy Panel (www.advocacypanel.com.au) as part of its grants process for consumer advocacy projects and research projects for the benefit of consumers of electricity and natural gas. The views expressed in this document do not necessarily reflect the views of the Consumer Advocacy Panel or the Australian Energy Market Commission.

Review of Energy Market Frameworks in light of Climate Change Policies

Final Report

Observations and issues

Introduction

At a time of great flux in both political and market arenas, we would like to offer some perspectives on some of the big ticket market design questions facing the electricity industry, taking our lead from the Australian Energy Markets Commission (AEMC)'s final report from the recent "Review of Energy Market Frameworks".

This was a very necessary review and one that promised so much, but which looks set to deliver so little. Recommendations in key areas such as transmission are acknowledged to be incomplete even though "frameworks will be challenged". The report refers to its being a "sound basis for the *initial* adjustment of frameworks". After over a year of review, this is disappointing, and we think the exercise as a whole represents a big missed opportunity.

We set out below comments on the review, its short-comings and some related work streams. More detailed observations on the recommendations are included in the attachment.

Why the review disappoints

The basic failure of the review and the work of the AEMC on market redesign more generally is to get the measure of the fundamental challenges posed by the Renewable Energy Target (RET) scheme, and the proposed Carbon Pollution Reduction Scheme (CPRS) or its alternative and the significant impacts these measures will inevitably have on the investment environment. This has occurred in a market that is already facing important issues about timely delivery of capacity and which is only just starting to try to come to terms with the immensity of the challenge that must be faced in decarbonising the generation sector in relatively short time-scales. The deep operational challenges and investment impacts that this will give rise to have scarcely been addressed as yet.

Many other electricity markets globally are experiencing real teething problems as they implement similar policies. They are also assimilating high levels of wind penetration and the impacts of carbon pricing, but our politicians and regulators seem disinclined to learn from these experiences.

Consequently the review's recommendations are generally low level and fail to address the key challenges. In particular the implementation plan set out in the final report is little more than a disjointed check-list of actions. It is not a strategy for updating the market settings or a coherent action plan for bringing forward the necessary market reforms. These shortcomings are already reflected in the Ministerial Council on Energy's (MCE) decision to launch a further root-and-branch review of transmission frameworks.

The separate review of demand-side participation (DSP), now in its third stage, still drags on after nearly three years. Indeed it's disappointing that outcomes of this work stream do not seem to have been anticipated or picked up in the energy market frameworks review.

There are also other on-going reviews such as the National Framework for Electricity Distribution Network Planning and Expansion and the Reliability Panel's Review of

Reliability Standards and Settings that should have been assimilated. Other omissions relate to the implications of active network management and impact of technological change and “smart” innovations, which have not been addressed within the review. Together with the DSP work, these are all key building blocks in establishing an enduring single coherent framework, and they should have had an important read-across to the AEMC’s thinking. However, rather than a coherent, joined-up market audit, we are left with a series of disjointed overlapping initiatives that is less than the sum of the parts.

There must also be question-marks over the robustness of many of the review’s findings. There are multiple statements that current market frameworks are broadly resilient. But it is not obvious how this conclusion has been reached by the AEMC. What assessment criteria have been applied and what are the defined measures of success? What stress testing has been carried out, and what development scenarios have been assumed? How is market failure defined and how do the proposed measures pre-empt it?

Indeed many of the likely challenges in the electricity market in a carbon constrained world are not specifically addressed or not in any detail. To give some examples:

- with high-levels of wind power on the system, centrally set prices would not only be on an upward trajectory, but also one that will see considerable volatility, and during high wind/low demand periods market prices could tend to go negative;
- as well as creating a need for more peaking plant to deal with intermittency, base load plant will, over time, be pushed down the merit order given high levels of “must-run” plant, but its ability to operate profitably will be limited by the NEM price cap;
- such plants will have to operate at low and highly uncertain loads, facing much more uncertain revenues, which will affect their viability and in turn will impact on the attractiveness of new investment;
- the current approach to setting the price cap is probably out-moded and does not reflect the impact of carbon pricing;
- little thought has been given to the specific measures the AEMO will need to take as system operator and reserve trader to evolve to address these challenges beyond expanding its short-term contracting role;
- how might this changed role impact on the energy market and price setting; and
- during the transition to an effective carbon price what steps will be necessary to prevent incumbents capturing carbon rentals?

All in all investors in this environment will process market risks and make their assessments of projects and required returns in a very different way, but the report simply does not address this sea-change and its implications.

Against this background, and the apparent absence of a methodology to test the review’s findings, the Commission’s headline conclusion––“the energy market framework is generally capable of accommodating the impacts of climate change policies efficiently and reliably”––lacks conviction. This failure comes out most clearly with regard to the question of introducing capacity incentives: “We have not been persuaded of the need to evaluate other electricity market design options as possible alternatives to the current “energy only” market design of the NEM.” This is apparently because “to contemplate such a review would introduce unnecessary trading and investment uncertainty at this critical time for the energy market” (pviii).

But the AEMC does not demonstrate that this prudent approach is proportionate or appropriate, although it does acknowledge that there is likely to be material increases in “wholesale and retail prices”.

This lack of ambition inherent in the AEMC’s review and its recommendations contrasts with the *Energy Market Assessment* [1] underway by officials in Great Britain and the recently concluded *Project Discovery*[2] carried out by the energy regulator Ofgem. The fundamental premise behind both these analyses is that there is a limited window of opportunity for policy-makers and regulators to pro-actively scope the major changes needed to decarbonise the generation sector, more actively integrate demand-side response and properly implement effective carbon pricing. We believe this is a message our own regulators and policy-makers need to heed and quickly.

Further notes on these two projects are at appendix 1 and 2 respectively.

Flawed recommendations

Turning to the main recommendations, we would make the following headline points:

- **Retail deregulation**

The challenges for retailers and customers in responding to carbon pricing––assuming this can be implemented in a timely an orderly manner––are much greater than acknowledged by the AEMC. The issue is not just about enabling effective pass-through by suppliers of environmental costs and levies. Customers need to have visibility of environmental costs and levies collected though retailers, and Governments need to have strategies to deal with impacts on vulnerable customers.

Further there will remain significant latent market power issues even with new entry, especially in householder and small business retail markets where evidence continues to suggest continuing high numbers of “sticky” customers. The recommendations to remove regulation from the retail sector are accordingly naïve, although I support the recommendation for a safety net tariff for customers unwilling or unable to take up a competitive market offer. There will also be a continuing need for effective reporting by retailers and surveillance even once price controls have been lifted. Interactions with upstream businesses in an increasingly integrated environment also need to be transparent and possibly regulated.

In this context there are useful lessons from the recent *Energy Supply Probe*[3] in Great Britain where quality of competition in energy retail markets was deemed to be significantly reduced almost a decade after price controls were lifted, despite a track-record of regulatory statements about the health of competition based purely on high-level switching statistics.

- **Generation clusters and strategic investment by networks**

The key issue for regulators is how to properly incentivise strategic investment by network service providers, not just how to appropriately size new or augmented connection assets. The arrangements proposed by AEMC do not address this central issue, and they appear bureaucratic, involving second-guessing by AER based on advice from AEMO. Perhaps differential returns could be allowed depending on network companies’ record of delivering useful assets to avoid stranded assets and to avoid consumers picking up the tab for these.

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[1] Energy Market Assessment. DECC. http://www.decc.gov.uk/publications/basket.aspx?filepath=1_20100324143202_e_%40%40_budget2010energymarket.pdf&filetype=4

[2] Project Discovery. Ofgem. http://www.ofgem.gov.uk/Markets/WhlMkts/Discovery/Pages/ProjectDiscovery.aspx

[3] Energy Supply Probe. Ofgem. http://www.ofgem.gov.uk/Markets/RetMkts/ensuppro/Pages/Energysupplyprobe.aspx

The recommendations also fail to address the need for orderly connection procedures where capacity is over-subscribed, capacity hoarding by incumbent generators, and interactions with infrastructure delivery.

The AEMC may be aware of a recently concluded review[4] of incentive-based regulation carried out again in Britain, which has focussed on:

- giving longer-term incentives to companies to identify better investments;
- improving scope for companies to innovate, including implementation of a Low-carbon Network Fund; and
- basing regulation more clearly on delivery of agreed outputs established in collaboration with stakeholders.

This comprehensive review by Ofgem seems to have addressed similar problems and challenges, but arrived at very different conclusions from the AEMC.

But ultimately we would suggest that both reviews have failed to make progress on one further key issue – how to accurately and predictably account for the value of emissions in decisions on infrastructure investment, and this needs to be rectified.

- **Transmission pricing**

It is difficult to assess the materiality and hence the impacts of the recommendations presented in the report as the specific recommendations are high-level.

The review has focussed on a mix of disparate elements of the current transmission charging arrangements. It is hard to disagree that a locational charge for generators, mechanisms to deal with congestion charging and inter-transmission company export charges are worthy of further consideration. Indeed these are all legitimate market design questions that exist independently of the impact of climate change policies. However the issues associated with changing network design and planning and their use in the light of CPRS and RET––including the impact on investment and operational decisions by generators and network businesses––do not seem to have been adequately explored. Further, in all three cases where recommendations are made relating to transmission charging, the nature of the proposed mechanism is not defined.

The MCE's subsequent decision to launch a further root-and-branch review of transmission frameworks is welcome, but should have been unnecessary if the AEMC had properly addressed the issue and interactions between the energy market and networks during its review.

- **System operations**

The assumption that "current frameworks for managing the power system provide a sound foundation" may well be valid. The AEMC also notes that in the NEM "we consider the frameworks are broadly resilient". However we are not clear how these statements are consistent with the recommendation that the mechanisms available to the SO need to be expanded, including increased scope to act as the reserve trader through short-notice reserve contracting, to deal with the management of potentially tight capacity margins. In this context the report fails to adequately address the potential role of the demand-side in broadening the options available to the SO.

There is merit in the recommendation that the "spot market price cap might require significant adjustment over time" (although this should read "will"). But it is the

[4] RPI-X@20 review. Ofgem. http://www.ofgem.gov.uk/Networks/rpix20/Pages/RPIX20.aspx

mechanism that underpins how the cap is raised that will determine investor and market participant confidence, and it therefore needs to be defined and the review has not progressed understanding of this issue at all.

Again one is left with the impression that a valuable opportunity to provide a fresh view on the challenges posed by RET and CPRS has been passed up.

Other matters

Significant investment in new low carbon generation assets is not likely to occur until a robust carbon price emerges. There is abundant experience from Europe as to how this transition should **not** be handled. This shift will inevitably have wide-ranging implications for prices and customers, which are not acknowledged in the review.

Finally the terms of reference for the review were unnecessarily constrained so that the interaction of energy price setting with capacity pricing was not considered. Although the energy only price is a key element of the current market settings, the interactions between capacity prices and the implications of increasing spot market price caps should have been explored. Indeed any consideration of the impact of climate change policies on investment is flawed without it.

Attached are more detailed comments on the specific recommendations made by the AEMC.

Attachment

Detailed comments on energy market framework review recommendations

Recommendations for change to existing energy market frameworks

The MCE reaffirms its commitment to remove retail price regulation in those jurisdictions where competition is effective. *The MCE clarifies that retail price regulation should result in regulated prices that provide headroom for the development of competition whilst also adequately protecting consumers unwilling or unable to take up a competitive market offer.* *Those jurisdictions that have not removed retail price regulation by the commencement of the CPRS should introduce additional flexibility to retail pricing regimes.*

The regulatory challenges in responding to carbon pricing––assuming this can be implemented in a timely and orderly manner––are much greater than acknowledged by the AEMC in the final report. The implications and impacts are much wider than bolstering the case for simply removing retail price controls or where this is not possible introducing flexibility in price caps.

The lessons learnt from the British *Energy Supply Probe* from 2008 should be heeded here, and illustrate that there is a need for ongoing regulation of retail energy markets once price caps have been removed. Key messages from the British study are that:

- without price controls retail profits have been loaded onto consumers that have never switched from their incumbent retailer, or from those that buy electricity as a single fuel rather than a dual fuel offer. In essence the state of competition at a regional level within Great Britain is less developed than the regulator had previously insisted it was when talking of the market in national terms. The result was that those customers that had never switched (around 50% after ten years of retail competition) were cross-subsidising offers presented to new customers outside of the former incumbent retailer's pre-liberalisation supply area;
- the regulator has in effect acknowledged that it had not been effective in monitoring the situation following the removal of price controls, which should be a salutary lesson for Australian regulators. Licence conditions regulating market behaviour have been belatedly tightened (especially non-discrimination requirements). Information disclosure by the regulated companies on their segmented activities has been increased (although it remains poor). Having no price regulation should not be confused with no regulation;
- new entry has been limited and many new entrants have failed to stay in the market (even with headroom built into residual price controls) or have remained niche players, and the market has been characterised rather by consolidation; and
- the electricity wholesale market was (and remains) largely illiquid, primarily due to the market framework incentivising generation and retail business to vertically integrate, rather than contracting as envisaged by market designers, and thus increasing barriers to new entry. Independent retailers cannot be expected to manage the new risks appropriately if the traded markets are immature. In the

absence of limits on vertical integration, ongoing regulatory oversight is needed until appropriate levels of market liquidity can be established.

Similarly experience from other liberalised energy markets has shown that efforts to introduce carbon pricing inevitably result in a more complex market place and greater policy and regulatory uncertainty, and the challenges for policy-makers and regulators extend well outside of price regulation. For instance the European Union's emissions trading scheme (EU ETS), introduced in 2005, has failed after nearly six years to deliver an adequate carbon price signal, due to free permits being widely allocated and lax emissions reduction targets being set. This has led to policy makers in Great Britain and some other European markets to explore alternative mechanisms to augment the European carbon price with a national mechanism.

But in the meantime there is an insufficient signal to incentivise fuel switching away from fossil-fuel sources, which means consumers are seeing the full carbon costs passed-through by retailers, but they are seeing few benefits through increased carbon abatement.

The National Electricity Rules should be amended to introduce a new framework for the connection of generation clusters in the same location over a period of time. The recommended model overcomes the lack of commercial incentives for network businesses to bear the risk of building assets to an efficient scale.

A transmission charge should be introduced to signal network costs to generators, in particular the extent to which costs vary by location.

Pockets of material and transitory congestion within regions should be priced, where the costs of introducing a pricing mechanism are proportionate to the materiality of the localised congestion problem.

The existing transmission charging framework should be amended to introduce a new regime that levies a load export charge between regions from one transmission business to another. This will improve the cost-reflectivity of charges and the allocation of costs across regions.

In principle, generators should be able to negotiate and pay for an enhanced level of transmission service – over and above the level efficient for customers to fund – but this needs further analysis for practical application.

As a general issue AEMC seems to confuse transmission issues that need to be addressed as part of enhancing the current market design and those that arise as a consequence of new climate change policies.

The key underlying issue triggered by CPRS/RET is how to incentivise network operators to invest strategically. The arrangements proposed by AEMC appear bureaucratic, and involve second-guessing by AER based on advice from AEMO.

There are at least two further factors that need addressing. Firstly there is the need to establish regulatory rules for networks that incentivise investments for the long term (rather than one that encourages asset sweating and short-term investment horizons) and which might accommodate generation clusters. Secondly Australia needs an access and charging regime that fairly accommodates first-comers in a cluster, perhaps based on location, but also proportionately charges intermittent generation.

Load export charging may help, as might locationally differentiated charges to generators. But these proposals come across as ad hoc and fall a long way short of an appropriate, holistic and enduring transmission charging methodology.

In terms of transmission service levels, generators should also be able to negotiate both lower levels of service, if for example the plant was primarily designed to meet the needs of an onsite customer, but also higher levels too.

In fact the AEMC seems generally to have taken a narrow view of the challenges and possible solutions, which is in considerable contrast to recent British experience. In Great Britain the 20 year old network regulation regime was recently reviewed to consider what changes might be needed to meet the challenges of moving to a low-carbon economy. The conclusion is (subject to final regulatory ratification later this year) that a new regulatory model will be phased in to replace the established CPI-X model.

A new “RIIO” model––Revenue set to deliver strong Incentives, Innovations and Outputs—has been styled “sustainable network regulation.” The new model retains the fundamental ex-ante approach and the “building block” model that is used in both Australia and Britain to assess efficient costs of delivery, depreciation allowances, and an allowed return on regulatory asset value.

The most significant change under the RIIO model is to encourage more longer-term thinking so that network companies are more open to considering options that reduce costs over longer time-frames and take a more far-reaching view when determining the scale of required network investment. A key part of this new approach is to extend the regulatory price control period from five to eight years, at least for the first review period. Although this new approach has yet to be fully tested it demonstrates the recognition from regulators and policy makers that regimes designed to facilitate liberalisation and drive down inefficiencies are not necessarily fit for developing low-carbon markets.

Further experience from the British market has highlighted the need to explore transmission capacity sharing arrangements in areas where constraints are likely to persist as generation becomes commissioned at a faster rate than new transmission capacity (a realistic and more complex challenge than generation clustering). There has also been a need for expedited access to beat lengthening “queues” of developers seeking access to finite capacity sometimes in weak areas of the network. A *Transmission Access Review*[5] addressed these and related issues and took almost three years to define and deliver a "connect-and-manage" approach to access rather than the historic "invest-then-connect" approach to accommodate new generation.

The revised approach gives a connecting generator the right of firm access (or compensation in lieu of this) under an accelerated timetable based on the completion of any localised connection works. Wider network reinforcement continues, if necessary, after it has been connected. Local congestion charges are identified but they are smeared back across all grid users, and a local user-pays charge has been specifically rejected by the Government on the grounds that impacted parties cannot respond to costs targeted in this way.

Capacity sharing and limited access trading arrangements have been introduced too, although the transmission charging regime is still to be reviewed to address (among other things) concerns that intermittent generation still faces unfair costs even with expedited access. Interestingly it is likely that the review will reconsider the current

[5] Transmission Access Review. Ofgem. http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Pages/Traccrw.aspx

approach to levying charges on generators and the current locational signals already embodied in them. An important consideration here is likely to be that generation investment has limited ability to respond to locational charge signals, a point noted but then rejected by the AEMC.

The British experience with regard to the transmission framework is in many ways mixed, with a more complete transmission charging review yet to be taken forward in earnest. But it demonstrates the intractable nature of many of the problems being faced and the need for a much more joined-up assessment of the challenges.

Against this background, the MCE's subsequent decision to launch a further root-and-branch review of transmission frameworks is welcome, but should have been unnecessary if the AEMC had properly addressed the issue during its review.

The set of options which AEMO can call upon to procure reserve to address capacity shortfalls should be expanded further than the current RET and directions power.

Arrangements for system operation should be reformed. The transparency of actions taken, and the resulting costs should be increased through additional reporting. This would be used to inform the consideration of further reform options, which should include options to introduce greater competition and cost-reflectivity.

As noted above it is not apparent how the report's statement that "current frameworks for managing the power system provide a sound foundation" is consistent with the recommendation to provide the SO with mechanisms to act as the reserve trader or manage potentially tight capacity margins. I agree that the SO will require a much larger tool-kit to deal with new operational challenges, and from this perspective it is disappointing that the report fails to adequately address the potential role of the demand-side in broadening the options available to the SO.

There is also merit in the recommendation that the "spot market price cap might require significant adjustment over time". But it is the mechanism that underpins how the cap is raised that will determine investor and market participant confidence, and it therefore needs to be defined and the review has not progressed understanding of this issue at all.

This course of action should not in my view though preclude consideration of capacity payments given the high and volatile nature of prices that will inevitably emerge with high levels of wind development. The issue of the cap, how it should be set and capacity payments are intimately linked.

There are also various references in the final report to the need for further review and reform to operational arrangements (e.g. frequency and voltage levels; access standards; and responsibilities and accountabilities for recruitment and delivery of essential ancillary services), but these actions are seen as necessary to ensure the effective long-term management of the power system. Investor confidence in new plant will be undermined if a programme of regular reviews of different aspects of market settings is introduced.

At the heart of any system operation reform must be greater transparency of actions taken and the associated costs. As the generation mix changes, and increased levels of intermittency appear on the system, clear and regular reporting of system operator actions must be communicated to the wider market to highlight areas where costs may be artificially high (for example constraints) and to monitor if forecast system operation costs are close to actual outputs.

Recommendations for change <u>within</u> existing energy market frameworks

MCE should review the existing timetable of the AEMC retail competition reviews. Specifically, for the timing for the Australian Capital Territory, New South Wales and Queensland reviews should enable the jurisdictions to make informed decisions on the need for price regulation before June 2012, when the CPRS is operational and the administered price of ten dollars per tonne is removed.

Agree subject to the caveats noted previously.

The National Energy Customer Framework should be implemented to ensure effective arrangements are in place for Retailer of Last Resort and customer protection prior to the commencement of the CPRS.

This could be a very important element of ensuring customers are properly engaged in the development process. Work should be conducted in parallel with that to put in place monitoring arrangements to assess the cost-effectiveness of the CPRS to ensure it delivers value-for-money.

The quality of information on demand-side capability should be enhanced and made available to AEMO through improved demand-side participation reporting. This will improve the ability of AEMO to make more informed decisions about when reserve shortfalls may occur.

The fact that the concurrent review of demand-side management arrangements did not factor in this review is an indictment of the continued tendency to separate supply and demand development issues.

System operators should gain a better understanding of the needs of demand-side users and the actual opportunities that to help balance the system.

The generation capacity potentially available to the market should be enhanced by facilitating the use of existing but under-utilised embedded generators.

The existing Demand Management Incentive Allowance under the National Electricity Rules should be expanded to accommodate connections of embedded generators. This may further encourage distribution businesses to deliver cost efficient connections for generators.

The role of embedded generation and how this will change as it grows is an area of real weakness in the report. There is significant potential for embedded generation to reduce network reinforcement and meet renewables/ low-carbon targets. The review did not sufficiently consider how the current regime rewards embedded generation (in terms of use of network charges) or how wider ranging reviews of system operation and amendments to the National Electricity Rules could deter or encourage future investment in decentralised generation.

The AEMC Reliability Panel should take account of the likely interactions between the electricity and gas markets when reviewing reliability market standards and settings.

AEMO should review the existing provisions in the National Electricity and Gas Rules to ensure it can appropriately co-optimise its decisions on market interventions.

The role gas plays in the electricity sector, and increasingly so as more flexible gas-fired plant is expected to come on to the system to cope with greater levels of intermittency with peaks and troughs on windy and still days, has not been properly explored, and is a big hole in the review. Within-day fluctuations on the gas system could also be an important limiting factor on the ability of the electricity system to cope with these operational challenges. The proposed review should be taken forward quickly.

Co-optimising decisions on appropriate gas and power market interventions is also clearly desirable, provided this aims to also simplify, streamline and introduce common governance/ terminology. The reasons for possible market interventions need to be fully understood by all participants to ensure the desired outcomes are delivered.

Appendix 1: BRITISH Energy Markets Assessment

The British government issued its Energy Market Assessment (EMA) in March 2010. The work stream is being undertaken by the Department of Energy and Climate Change (DECC) and HM Treasury. It concluded that the current market framework would need further reform if it was to deliver the necessary investment beyond 2020, and set out a series of options that share much in common with options for reform set out in GB regulator's *Project Discovery*.

The Government has taken the opportunity to dismiss options at either end of the spectrum that promised either too little or too much change. DECC has also presented initial findings from the Road-map to 2050 analysis promised last July as supporting its conclusion that decarbonisation would provide significant challenges for the energy markets beyond 2020.

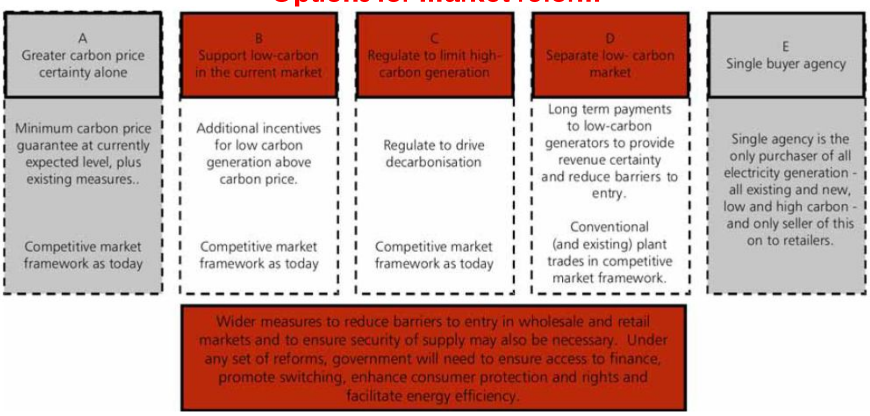
The assessment is particularly important as it is the first official review of how the market is meeting new policy objectives. Overall it presents a relatively relaxed view about security of supply to 2020, but with mounting risks thereafter. The clear implication is that market arrangements will, in the Government's opinion, send the necessary price signals to bring new construction forward, especially from wind and gas.

The achievements to date of the Renewables Obligation in driving investment are charted. But wholesale market liquidity problems are acknowledged, and the retail market "has not been functioning as dynamically as it could". A range of barriers to entry are identified, and "consumers also lack confidence in the effectiveness of the market". Existing workstreams will continue on measures to strengthen competition and consumer protection culminating in a discussion document on measures to enhance consumer rights and confidence.

The main focus of the document is delivering scale investment in low-carbon generation. The concern is that if current market frameworks are not reformed Great Britain will miss its emissions reductions objectives after 2020. Four factors were presented as areas of concern that will place "challenging requirements on the market framework":

- the economics of low-carbon technologies: high upfront capital costs and low operational costs means they are more exposed to uncertainty in future prices, so over the medium term investors may lack confidence in making a reasonable return;
- the financing requirement of low-carbon generation: this will require "unprecedented" levels of capital expenditure and construction risk that may exceed the capacity or appetite of existing investors;
- security of supply: investors may not see the right signals to invest in the assets to provide flexibility to meet the increased intermittency and inflexible generation expected on line during the 2020s; and
- concerns about efficiency and fairness: substantial barriers to entry are restricting innovation and competition, and the changes required to meet the carbon

Options for market reform



reduction challenge are already placing increased pressure on prices.

The Government set out five options for reform of the framework with increasing levels of intervention. The options in grey (A and E) mirror *Project Discovery's* "end-of-spectrum" options, but have been dismissed as too extreme.

The focus of the remaining options is how to support the development of low-carbon generation. Methods of ensuring security of supply are characterised as additional measures that may be required once the broad direction of travel has been fixed, although no wider discussion of trading arrangements were included, but the implicit assumption is that current arrangements are not able to meet the challenges.

Option B would support low-carbon in the current market. Government would intervene to increase and make more certain the degree to which low-carbon generators receive additional revenue compared to high carbon generators. This could be achieved through mechanisms such as a low-carbon obligation on suppliers, a system of "premium" feed-in tariffs for generators or the contract-for-differences approach against the electricity price.

Option C would regulate to limit high-carbon generation. The Government would introduce regulations to limit the amount of high-carbon generation that can be built and/or to limit its operation. This appears the least favoured option currently, due to significant regulatory risks and security of supply risks.

Option D would introduce a separate low-carbon market. A guaranteed revenue stream is developed for low-carbon generators separately from the existing wholesale market. The price could be set through a competitive tendering approach, possibly led by government itself or by regulation of an appropriate rate of return.

Since the publication of this report a new Coalition Government has come to power. It too sees the need for market reform and early indications are that the new administration is seeking to introduce changes similar to those set out in options B and C above.

Appendix 2: Ofgem's Project Discovery

The British regulator, Ofgem, launched its *Project Discovery* work stream in mid 2009 to assess the challenges to Britain's gas and electricity supplies in the coming 10-15 years.

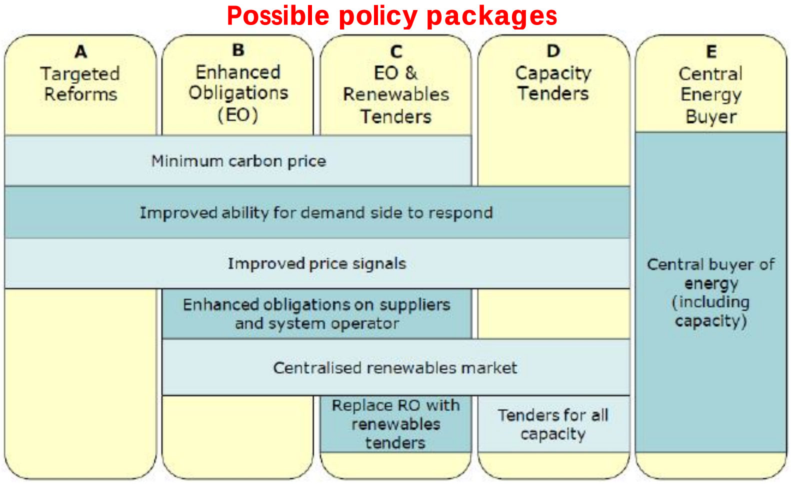
The regulator drew up four energy scenarios to analyse the various energy security risks up to 2025. They represented a diverse range of futures that Ofgem used to test current arrangements and potential future policy responses. The scenarios incorporated two key drivers: the speed of economic recovery from the global recession and the extent of a globally co-ordinated environmental action plan. The two drivers will affect future energy supply and demand and influence policy decisions on both a national and international level, Ofgem argued.

Ofgem identified the need for investment to the order of £200bn in power plant and other infrastructure up to 2020 to secure both energy supplies and climate change targets. This level of investment implied doubling the recent rate of investment and under all four scenarios a rise in consumer bills was expected. This was due, Ofgem said, to the level of investment needed and the increasing costs of carbon, and these increases could be exacerbated if oil and gas spot prices rise sharply or continue annual incremental rises experienced since 2003. In addition, Ofgem identified a number of other key risks emerging from the four scenarios over the next decade:

- some scenarios show that environmental targets (including the EU renewables target and UK carbon budgets) are not met or are at risk of not being met;
- Britain could face significant levels of gas imports, especially where environmental measures only achieve fractional success. Gas dependency could be worsened by growth in gas-fired power plants to replace nuclear and coal-fired capacity in some scenarios;
- continued expansion of renewables would soften the risk of gas import dependency, but an increase in renewables would require thermal plant to operate more flexibly to offset the inevitable variability in wind output. This may require yet further investment;
- further reliance on renewables may bring about significant changes in the way the country generates and consumes power due to the inherent variability in some technologies;
- maintaining gas supplies through a severe winter could be the greatest risk to security of supply; and
- forecasting future gas demand has been made increasingly difficult due to the uncertainties in the impacts of environmental policy. This could delay investment in gas infrastructure that could become necessary should environmental measures not achieve their objectives.

The exercise concluded with five potential remedy packages as possible responses to scenarios designed to pick out the major risks to secure, low-carbon British energy supplies. These are:

Possible policy packages



- Package A: The focus is on a minimum carbon price so that investors in low-carbon technologies might have more confidence in a future premium for them in wholesale power prices. It might be set forward, for instance from 2020, and is intended primarily as a tool for longer-term investment. EU ETS participants would still trade but pay a top-up tax if allowances cost less than the minimum price. Alongside the minimum carbon price, changes to wholesale trading would strengthen short-term price signals.
- Package B: This approach would include, in addition to Package A, measures to promote security of supply principally through an obligation, possibly of three to five years duration, on suppliers. They would need to demonstrate sufficient contracted supply to cover their customers' demands against pre-defined security standards. Related measures could include obligations on the system operators to ensure back-up generation capacity and emergency gas is in place, and there may also be obligations on gas-fired generators to have back-up fuel. A centralised renewables market would be established for wind and other intermittent technologies alongside the current bilateral market, allowing them to avoid imbalance price risk. Ofgem said without this, or some other form of differentiated cash-out, sharpened price signals could be detrimental to investment in renewables.
- Package C: Additional to Package B the regulator considered tenders for renewables capacity to replace the Renewables Obligation for new large-scale renewables. A "central entity" would determine tendered contracts for capacity and delivery that offered premiums above market prices so investors might earn an appropriate rate of return over, say, a 20-year period. Generators would still be exposed to the wholesale markets for their electricity revenue and costs would be recovered from customers as a regulatory pass through item.
- Package D: This would introduce tenders for all generation capacity, new gas storage and other gas infrastructure to target "prescribed outcomes for security of supply and decarbonisation by specifying the generation mix and tendering for capacity." It would retain improved price signals, improved ability for the demand side to respond and the centralised renewables market of Package B but not the minimum carbon price given the tenders would bring forward specific technology investments. There would be a combination of long-term tenders for low-carbon generation plant, and shorter-term tenders for generation capacity more generally and demand-side response. To all intents and purposes this model would be a single buyer
- Package E: This represented the most extreme departure from current arrangements, and Ofgem noted that existing European legislation would limit the form and scope that it could take. Its objective would be to deliver prescribed outcomes for supply security and decarbonisation through a single co-ordinating investment entity. It is acknowledged that there is a significant risk that the buyer makes the wrong choices and over-contracts with consumers bearing the cost. Ofgem considered the different forms that the central buyer could take in electricity and gas. One model in electricity was it acting as a type of broker, buying all the output from generators and selling it to suppliers under standard terms in a kind of Bulk Supply Tariff for the 21st century. It would be likely to be implemented alongside a centralised despatch mechanism. There would be a pool of sorts, though most costs would be as specified under long-term contracts. In gas the central buyer would "only" be active in tendering for new gas storage,

ballasting and import capacity infrastructure and its scope could be extended to entering into long-term gas supply contracts.

These possible remedies market a departure from Ofgem's stance of the previous decade in which it pushed aggressively for market-based change across the board. The reality is that many systems internationally have already managed to achieve high levels of build of targeted technologies within a market setting. Spain has done it with wind; many US pools have managed to accommodate high levels of both nuclear and wind production, which can be characterized as "must run". And capacity management within electricity markets is the norm, not the exception. Many pools have also managed to achieve good integration of energy and transmission markets, which is a particular failure of the current British model, with demand-side bidding also having an established role.