Title:
Electricity Market Reform (EMR)
Final Investment Decision (FID) Enabling

IA No: DECC0083

Lead department or agency: DECC
Other departments or agencies: HM Treasury

Impact Assessment (IA)

Date: 08/05/2013

Stage: Final

Source of intervention: Domestic

Type of measure: Primary legislation

Contact for enquiries:
Shameem Shah, Oliver Rooke

Summary: Intervention and Options

RPC Opinion Status: Not applicable

Cost of Preferred (or more likely) Option				
Total Net Present Value	**Business Net Present Value**	**Net cost to business per year**	**In scope of One-In, One-Out?**	**Measure qualifies as**
£2.1bn	N/A	N/A	No	N/A

What is the problem under consideration? Why is government intervention necessary?

Current market arrangements are not expected to deliver the scale and pace of investment in low-carbon generation required to meet our long-term targets. EMR has been designed to tackle barriers to this investment. However, developers of low-carbon power projects that could take final investment decisions (FIDs) before the reform programme has been implemented are unlikely to invest until they have certainty over what the EMR Contract for Difference (CfD) regime will deliver. Without Government intervention to provide appropriate assurances, such investments are expected to be delayed or cancelled, increasing the cost of attaining decarbonisation, security of supply, and affordability objectives.

What are the policy objectives and the intended effects?

The primary objective of the policy is to remove uncertainty ahead of EMR, and so enable FIDs in advance of EMR implementation (expected 2014). Our analysis shows that enabling early investment decisions can deliver a more cost-effective generation mix through to 2030. This policy is therefore expected to contribute towards meeting the Government's decarbonisation, security of supply, and affordability objectives.

What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)

Government has a range of non-regulatory options to enable early investment decisions to progress to timetable. Options range from do nothing and letters of comfort through to entering into an investment contract (early CfD) with a generator (conditional upon any necessary State Aid approval and enactment of the Bill if entered into before this occurs). The form of intervention necessary to enable investment will vary by technology, project and developer, and the legislative provisions sought will ensure that the Government can deliver an appropriate level of certainty to enable investment in projects that meet the FID Enabling eligibility criteria.

Will the policy be reviewed? It will not be formally reviewed. **If applicable, set review date:** Month / Year

Does implementation go beyond minimum EU requirements?			**N/A**		
Are any of these organisations in scope? If Micros not exempted set out reason in Evidence Base.	**Micro Yes/No**	**< 20 Yes/No**	**Small Yes/No**	**Medium Yes/No**	**Large Yes/No**
What is the CO2 equivalent change in greenhouse gas emissions? (Million tonnes CO2 equivalent)			**Traded: -27MtCO2e**	**Non-traded: None**	

I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.

Signed by the responsible Minister: .... Date: 08/05/2013

Summary: Analysis & Evidence Policy Option 1

Description:

Recommended preferred option: Ability to offer an investment contract (early CfD) conditional on primary powers being secured and any necessary state aid approvals being granted.

FULL ECONOMIC ASSESSMENT

Price Base Year 2010	**PV Base Year** 2010	**Time Period Years** 20	**Net Benefit (Present Value (PV)) (£m)**		
			Low: -£20m	**High:** £20bn	**Best Estimate:** £2.1bn

COSTS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant	**Total Cost** (Present Value)
Low	Optional		Optional	**Optional**
High	Optional		Optional	**Optional**
Best Estimate	£20m			**£20m**

Description and scale of key monetised costs by 'main affected groups'

The financial resources required for the project relate to advisory fees (legal, commercial, financial and technical). These have been estimated based on DECC's experience of procuring such expertise. Costs of additional / earlier low-carbon generating capacity are netted off the benefits of reduced costs for other forms of generation in the benefit estimates below. Other costs include displacement of economic activity from other technologies and sectors.

Other key non-monetised costs by 'main affected groups' None.

BENEFITS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Benefit** (Present Value)
Low	Optional		Optional	**£0**
High	Optional		Optional	**£20bn**
Best Estimate				**£2.1bn**

Description and scale of key monetised benefits by 'main affected groups'

The benefits quoted above are net benefits to society of enabling early investment in low-carbon generating capacity, i.e. reduced overall electricity generation and system costs. The timing of investment typically pitches earlier capital expenditure (net cost to society), against lower operating costs, cost savings through learning, greater carbon benefits, reduced fuel costs, and lower marginal abatement costs as a more effective generation mix is delivered over time (all net benefits to society).

Other key non-monetised benefits by 'main affected groups'

- The option value of opening up a nuclear pathway in the 2020's.
- Benefits to supply-chain industries in each of the CCS, nuclear, and renewables sectors, in the form of direct additional economic activity and possible attraction of Foreign Direct Investment and increases in R&D spending which may have spillover benefits.
- Wider macroeconomic impacts of changing electricity prices.
- The value of early information gained through engagement with developers, which can refine on-going EMR policy work and inform later discussions with other developers.

Key assumptions/sensitivities/risks **Discount rate (%)** 3.5%

- The key assumption is there is no significant cost or penalty associated with an early price discovery process.
- Sensitivities have been run on nuclear deployment, fossil fuel prices and demand assumptions.
- The key risk is that the volume and type of technology that will be enabled through the project are uncertain, with the outcome dependent on the status of projects that come forward for the FID-Enabling process, engagement/discussions/negotiations with developers and progress with developing the CfD that will be available under the enduring EMR regime.
- The deployment rate of nuclear is uncertain and has a significant impact on the cost-effective generation mix. This is explored in detail in the analysis below.

BUSINESS ASSESSMENT (Option 1)

Direct impact on business (Equivalent Annual) £m:			In scope of	Measure qualifies
Costs: £0	**Benefits:**	**Net:**	No	N/A

Evidence Base (for summary sheets)

List of abbreviations:

CBA:	Cost Benefit Analysis
CfD:	Feed-in tariff Contract for Difference
CCGT:	Combined Cycle Gas Turbine
CCS:	Carbon Capture and Storage
DDM:	Dynamic Dispatch Model
DECC:	Department of Energy and Climate Change
EMR:	Electricity Market Reform
FID:	Final Investment Decision
HMG:	Her Majesty's Government
HMT:	Her Majesty's Treasury
IA:	Impact Assessment
JSC:	Joint Steering Committee
JV:	Joint Venture
NPV:	Net Present Value
O&M:	Operations and Maintenance
OCCS:	Office of Carbon Capture and Storage (DECC)
OCGT:	Open Cycle Gas Turbine
OND:	Office of Nuclear Development (DECC)
ORED:	Office of Renewable Energy Deployment (DECC)
PPA:	Power Purchase Agreement
RO:	Renewables Obligation
VfM:	Value for Money

Executive Summary

The Electricity Market Reform White Paper set out the Government's commitment "to work actively with relevant parties to enable early investment decisions to progress to timetable wherever possible, including those required ahead of implementation of the Feed-in Tariff with Contracts for Difference (CfD)".

A range of options are available to the Government to achieve this aim. Options range from do nothing and letters of comfort through to entering into an investment contract (early CfD) with a generator (conditional upon enactment of the Bill if entered into before this occurs and any necessary State Aid approvals). By seeking the necessary legislative provision through the Energy Bill, Government is ensuring that it can deliver certainty for investors in projects that meet the FID Enabling eligibility criteria, in a timely manner, thereby making positive final investment decisions in advance of EMR implementation more likely.

The aim of this Impact Assessment is to set out the justification for intervention to enable early low-carbon investment decisions, where projects meet the eligibility criteria set out for each technology group, and explore the potential impacts of preventing the delay or cancellation of new low-carbon electricity projects. The merits of individual projects are not discussed, nether is the level of support required to bring specific projects or technologies into existence.

Our analysis shows that enabling early investment decisions is likely to deliver a more socially cost-effective generation mix out to 2030. By offering greater certainty on policies to low carbon investors who are ready to make final investment decisions before EMR has been fully implemented, the Government will help deliver its decarbonisation and security of supply ambitions more cost-effectively and mitigate the downside risks of delayed or cancelled deployment of some low-carbon projects which may be associated with large welfare costs.

Our central case shows that there is a net welfare gain of £2.1bn (NPV) to 2030 associated with introducing an effective FID-enabling product for nuclear and renewables. This assumes that in the absence of FID Enabling, developers wait until the enduring EMR programme is implemented and reach financial close on low-carbon projects at the earliest in 2014. In the interim, generation from gas-fired CCGT and some unabated coal leads to higher generation and carbon costs.

However, there is a risk that where an investment decision does not take place in advance of EMR, it may not be revisited until much later, if at all, despite the policy certainty delivered on establishment of the enduring EMR CfD regime. In a world of high international capital mobility and diversified investment strategies, developers may choose to deploy their capital elsewhere; supply chain constraints could cause developers to lose their position in the order book for key manufactured components; and established positions such as joint venture partnerships and other business-critical agreements could break down ahead of 2014.

This outcome is more likely for very large investments such as investments in nuclear. To illustrate the impact of such scenarios, our analysis shows that a 5-year delay to nuclear deployment leads to a net cost of £15bn, rising to £22bn if the new nuclear programme does not go ahead at all though inevitably these figures are highly sensitive to the assumed cost of new nuclear. This is because a five-year delay or cancellation of the assumed programme of new nuclear deployment would lead to a less optimal generation mix with significant increases in generation costs and capital costs, assuming a competitive price is achieved for nuclear. In these delay and cancellation scenarios, generation and carbon costs rise due to higher dispatch from unabated gas and coal plant, and capital costs rise due to a greater reliance on higher cost renewable technologies and CCS-equipped generation to meet our decarbonisation ambitions.

A number of modelling assumptions will affect our assessment of the benefits associated with the scheme, and it is important to recognise these uncertainties. Specifically, the benefits will depend on the assumed counterfactual and the different input parameter assumptions, such as technology costs, build rates, fossil fuel prices, carbon prices, and aggregate demand levels. The success of the scheme also depends on attracting projects that represent value for money for consumers. Any product we may offer may not be attractive to all eligible projects and there is inherent uncertainty over the number of projects that we may be able to incentivise.

This analysis provides a justification for engagement with interested parties through the FID-Enabling process.

1 Introduction:

1. FID Enabling and EMR

The Electricity Market Reform White Paper set out the Government's commitment "to work actively with relevant parties to enable early investment decisions to progress to timetable wherever possible, including those required ahead of implementation of the Feed-in Tariff with Contracts for Difference (CfD)". In the December 2011 publication "Planning our electric future: technical update", DECC committed to entering into discussions with relevant developers with a view to considering what form of comfort might be given to support the taking of such investment decisions. The Final Investment Decision (FID) Enabling Project is designed to deliver these commitments.

The project is an important element of the pathway for delivery on the EMR and wider Departmental objectives of decarbonising the electricity grid, ensuring security of supply, and maintaining affordability.

2. The FID-Enabling Products

A range of options, or products, are available to the Government to enable early investment decisions to progress to timetable where eligibility criteria are met, including those required ahead of implementation of the Feed-in Tariff with Contracts for Difference (CfD). Options range from do nothing and letters of comfort through to entering into an investment contract (early CfD) with a developer (conditional upon enactment of the Bill if entered into before this occurs and any necessary State Aid approvals).

The actual form of intervention necessary to enable investments will vary by project and developer, and it is impossible in advance of sufficient engagement with developers to understand all the project-specific issues that an enabling product should be able to address. As a result, it is not possible to identify a single preferred option for delivery. However, discussions with developers indicate that for some projects key issues will include certainty on terms of the CfD including the contract duration, risk allocation and strike price (all of which have a bearing on the financeability of projects). In such circumstances, anything short of a binding arrangement on these points is likely to be insufficient comfort to enable some developers to commit to a final investment decision ahead of full implementation of EMR.

To secure this, the Bill includes powers for the Secretary of State to give effect to any investment contracts (early CfDs) that he enters into ahead of full implementation of EMR, provided such contracts are laid before Parliament and other conditions are satisfied. (Note that any investment contract entered into before enactment would be conditional on this taking place, and any investment contracts issued would also be conditional on securing any necessary State Aid approval.)

3. The scope of FID Enabling

The project scope covers all low-carbon technologies, including Carbon Capture and Storage (CCS)-equipped fossil fuel plant, nuclear, and renewables. The opportunity to express interest in the FID-Enabling project is available to projects that require a final investment decision before EMR is implemented. The full eligibility criteria are set out in the Technical Update to the White Paper on Electricity Market Reform, published in December 2011 and were updated for renewables projects in March 2013.[1]

Large-scale renewable electricity generation is currently supported by the Renewables Obligation (RO). The RO will remain available until 31 March 2017, at which point it will close to new generation. To ensure a smooth transition, there will be a period where both the RO and CfDs are available to developers, when developers will have a choice of support mechanism.

In practice, there are a number of categories of renewables projects which could benefit from FID-enabling arrangements:

- Projects due to commission post 31 March 2017 (which will therefore make their FID on the basis of the CfD as the RO will have ended) due to take their FID before implementation of the enduring EMR CfDs regime (planned for 2014 (typically large offshore wind));

[1] http://www.decc.gov.uk/en/content/cms/legislation/white_papers/emr_wp_2011/tech_update/tech_update.aspx
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/141873/FIDeR_update_doc_Invitation_to_Participate_2013_-_03_-_14_FINAL.pdf

- Projects due to commission in 2016/17 (which risk missing the RO cut-off date because of uncertainty over construction times) due to take their FID before implementation of the enduring EMR CfDs regime.

4. What the FID Enabling Impact Assessment is and is not designed to do

This impact assessment analyses the costs and benefits associated with the timing of investment decisions. It does not fall within the remit of this analysis to comment on Government policy on low-carbon power generation technologies, nor to assess the level of support required to incentivise such investments.

Furthermore, it should be noted that the case for individual projects or categories of projects will be assessed on their own merits through the appropriate Government approvals processes, which will call for comprehensive value for money, risk and affordability appraisals. This Impact Assessment, therefore, only assesses the value of intervention to enable investment decisions prior to full EMR implementation, and does not discuss individual projects.

A summary of the arguments for Government intervention in the form of EMR, and the choice of the CfD as the mechanism of choice for addressing current market failures is provided in the background section below. Further information can be found in the relevant Impact Assessments for these topics.[2]

In summary:

- What the FID Enabling Impact Assessment is designed to do:
  - Assess the costs and benefits of Government intervention to enable investment decisions to proceed ahead of the full implementation of the EMR CfD regime.
- What the FID Enabling Impact Assessment is not designed to do:
  - Justify broader Government policy on low-carbon technologies.
  - Assess the level of support required to bring specific projects or technologies into existence.
  - Discuss the merits of individual projects.

[2] https://www.gov.uk/government/publications/planning-our-electric-future-a-white-paper-for-secure-affordable-and-low-carbon-energy
https://www.gov.uk/government/publications/energy-bill-impact-assessments

2 Background:

The following is summarised from the EMR Impact Assessment published alongside the Energy Bill and the reader is referred to this document for more information.

1. The rationale for EMR and the failures of current market arrangements

Decarbonisation

The Government is committed to meeting the legally binding decarbonisation targets as set out in the Climate Change Act 2008, and economy-wide carbon budgets.

New Government clauses have been added to the Energy Bill which enable a 2030 decarbonisation target range for the power sector to be set in secondary legislation. The decision to set a target range will be taken once the Committee on Climate Change has provided advice on the 5th Carbon Budget, which will cover the corresponding period (2028 – 2032), and once the Government has set that budget, which is due to take place in 2016. The power will not be exercised until the Government has set the 5th Carbon Budget.

Whilst the UK is on target to reduce its greenhouse gas emissions in 2020 by 34% on 1990 levels, in line with carbon budgets and the EU target, the longer-term goals are more challenging. From 2020, further deep cuts in emissions from the power sector are likely to be necessary to keep us on a cost-effective path to meeting our 2050 commitments. Reducing emissions from the power sector will become increasingly important to help us decarbonise other sectors. However, there are reasons to believe that the current market arrangements will not deliver decarbonisation at lowest cost.

Cost structures differ between low-carbon and conventional generation capacity investments. Low-carbon investments are typically characterised by high capital costs and low operational costs, while fossil-fuelled generation capacity tends to have relatively low capital costs and high operational costs. The current electricity market was developed in an environment where large-scale fossil fuel plant made up the bulk of the existing and prospective generation capacity, which presents a particular challenge for investment in low-carbon generation.

In the current market, the electricity price is set by the costs of the marginal generator, which is typically a flexible fossil fuel-fired plant. Fossil fuel generation therefore sets the price for all generation in the market, including low-marginal cost low-carbon generation such as nuclear and wind. This means that the electricity price, and hence wholesale electricity market revenue, is typically better correlated with the costs of a fossil fuel-fired plant than it is to the costs of low-carbon plant.

Non price-setting plant is therefore exposed to changes in the input costs, including both fuel and carbon, of price-setting plant. If these costs increase, revenues for non-price setting plant increase; if they decline, revenues for non-price setting plant also decline. Therefore whilst non price-setting plant can benefit from increases in the input costs of price-setting plant - costs which the price-setting plant can pass through - they are exposed to lower fuel or carbon prices in a way that price-setting plant are not. This increases the risk of investment in low-carbon capacity relative to investment in conventional capacity.

Fossil fuel generators have benefitted over many years from learning by doing and the exploitation of economies of scale. There is evidence that given the opportunity to deploy at scale, some low-carbon technologies could reduce in cost. However, at current relative generation costs these technologies would be unable to compete with mature technologies in the market, even with the support of a carbon price. Therefore, there is a case for offering additional support to immature low-carbon technologies to drive innovation.

Under the current market arrangements, mechanisms such as the Renewables Obligation have been introduced to improve the risk-reward balance associated with renewable investment and drive innovation by providing an explicit revenue stream that is not dependent upon the wholesale electricity price. However, given the longer-term decarbonisation objectives, more is needed to provide an environment that is sufficiently attractive for low-carbon investment and to do so at lowest cost for consumers. The carbon price is unlikely to be strong enough to drive the necessary decarbonisation alone, particularly through current EU-ETS projections and even with the announced Carbon Price Floor trajectory.

It is possible that for some technologies, the market will find ways of managing some elements of the revenue uncertainty, such as through contracting between generators and suppliers or through vertical integration. However, this may result in unnecessarily high costs for consumers given the costs suppliers incur in managing this uncertainty.

As a result, the Government believes that the current arrangements will not be sufficient to support the required new investments in renewables, nuclear and CCS, and ensure these are delivered cost-effectively., There is also a clear need for appropriate signals for investment in new and existing fossil fuel plant. Therefore, revisions need to be made in order to deliver a sustainable low-carbon generation mix in a cost-effective way.

In addition, CCS also suffers from market failures relating to technological innovation. While there is an understanding of individual parts of the CCS chain, a fully integrated chain has not been applied to a power plant and there is a risk that the project revenue stream will not be realised. Furthermore, since cost reductions tend to occur over many years of deployment, early developers of the technology would face challenging financial returns and large financing gaps that would be hard to fill through the capital markets, which would likely persist until the full-chain CCS remains unproven. Without demonstrating the technology, there is likely to be an under-investment in CCS.

The Government is making available £1bn in capital grant funding to support early-stage CCS projects successful in the CCS Commercialisation Programme competition (launched in April 2012), in addition to ongoing support through the CfD. This intervention is aimed at overcoming the market failures identified. Beyond the early-stage CCS projects, future CCS projects will also need a supportive environment that encourages investment.

Security of supply

Electricity markets are different to other markets in a number of ways, two of which are particularly significant: capacity investment decisions are very large and relatively infrequent; and there is currently a lack of a responsive demand side as consumers do not choose the level of reliability of supply they are willing to pay for. This relates to the fact that load shedding occurs at times of scarcity on a geographic basis rather than according to supplier and as consumers do not respond to real time changes in the price of electricity. Smart Meters, which are expected to be rolled out by 2019, should help to enable a more responsive demand side but it is anticipated that it would take time for a real-time responsive market to evolve.

In absence of a flexible demand side, an energy-only market may fail to deliver security of supply either:-

- if the electricity price fails to sufficiently reward capacity for being available at times of scarcity; or
- if the market fails to invest on the basis of expected scarcity rents.

These conditions would tend to lead to under-investment in capacity and its reliability. While the market has historically delivered sufficient investment in capacity, the market may fail to bring forward sufficient capacity in the future as a fifth of generating capacity available in 2011 has to close this decade and as the power system decarbonises. The market may also fail to provide incentive for capacity built to be sufficiently reliable, flexible and available when needed. A Capacity Market mitigates the risk of an energy-only market failing to deliver sufficient incentives for reliable and flexible capacity.

In the Electricity Market Reform White Paper, we set out the potential market and regulatory failures in the current market that could prevent these signals from being realised.

The principal market failure is that there is no market for reliability: customers cannot choose their desired level of reliability as the System Operator does not have the ability to selectively disconnect customers.

In theory this problem is addressed in an energy-only market by allowing prices to rise to a level reflecting the average value of lost load (i.e. the price at which consumers would no longer be willing to pay for energy) and allowing generators to receive scarcity rents. This should lead to investment in the socially optimal level of capacity.

However, in reality an energy-only market may fail to send the correct market signals to ensure optimal security of supply. This is commonly referred to as the problem of ‘missing money’, where the incentives to invest are reduced, due to the two reasons below.

Firstly, current wholesale energy prices cannot rise high enough to reflect the value of additional capacity at time of scarcity. This is due to the charges to generators who are out of balance in the Balancing Mechanism (“cash out”) not reflecting the full costs of balancing actions taken by the System Operator (such as voltage reduction).

Secondly, at times when the wholesale energy market prices peak to high levels, investors are concerned that the Government/regulator will act on a perceived abuse of market power, for example through the introduction of a price cap.

The latter regulatory risk is exacerbated if there are significant barriers to entry, effectively restricting the number of participants in the wholesale electricity market. As margins become tighter and prices more volatile in the future, market participants may have more opportunities to withhold supply to drive up prices – particularly so as demand is inelastic and so there are potentially significant gains from withholding at times of scarcity. This could result in a greater likelihood of gaming in the energy market and difficulties in differentiating such gaming from legitimate prices, which would increase the risk that the Government may want to intervene in the wholesale market to cap prices.

This has not previously been a significant concern as prices historically have not risen above £938/MWh as a result of excess capacity on the system depressing wholesale market prices. In the future, analysis suggests that prices could need to rise to up to £10,000/MWh (or even higher) for short periods to allow flexible plant to recover investment. Investors are concerned that Government or the regulator would intervene if this were to happen. The perception of this regulatory risk could increase ‘missing money’ and under-investment.

2. Rationale for CfD and Capacity Market as delivery mechanisms for EMR

Contracts for Difference

The Government’s choice of the CfD as the preferred policy instrument was set out in full in the EMR White Paper (July 2011). However, in summary, the White Paper assessment considered two options for driving investment in low-carbon generation:

- A Premium Feed-in Tariff (PFiT), where all low-carbon generation receives a static premium payment on top of the wholesale electricity price;
- A Feed-in Tariff with Contracts for Difference (CfD) for all low-carbon generation, guaranteeing low-carbon generation a strike price for the electricity they produce, settled against an indicator of the wholesale electricity price.

The preference for a CfD over a PFiT was based on the CfD’s ability to promote static and dynamic efficiency through allocating risk efficiently between investors and consumers. This is achieved by allocating risk to those parties best able to manage or control it. For example, the CfD insulates investors in low-carbon generation from electricity price risk, which they are unable to control.

The impact of this risk being transferred is that consumers are not affected by higher wholesale prices (for instance caused by higher gas prices) but equally do not benefit from lower wholesale electricity prices (for instance caused by lower gas prices). Note that this is only the case for the part of their bill related to paying for generation under the CfD.

As a result of lower exposure to fossil fuel price risk and the greater revenue certainty which this gives, the cost of capital for investors in low-carbon generation is lower under a CfD than under a Premium FiT.

In order to isolate the part of the capital cost savings which are due to reductions in costs of capital, the latest Contract-for-Difference Impact Assessment[3] looked at what the capital cost under the EMR scenario would be with and without the hurdle rate reductions. The results suggest that, depending on the assumed level of decarbonisation in 2030, the cost of capital reduction due to CfDs would generate a positive social NPV of between £2.1bn and £4.1bn (up to 2030, including administrative costs).

Capacity Market

In a Capacity Market, capacity providers receive a payment for offering capacity which is available when needed but are able to sell their energy into the energy market. They are then required to be available when needed.

The lead form of Capacity Market assessed here as part of the overall lead EMR package is an Administrative Capacity Market (where providers are subject to administrative penalties in addition to energy market incentives if they fail to be available at times of scarcity and where providers are able to keep any revenues they earn in the energy market).

The alternative form of Capacity Market considered is a Reliability Market. Under this option providers are required to pay back the difference between a real-time reference price and the strike price. This insures consumers against the risk of price spikes and gives providers a market-based incentive to be available when needed.

The Administrative Capacity Market is currently the preferred form of Capacity Market for two reasons. Firstly, there is no appropriate reference price for a Reliability Market in the absence of cash out reform, as current prices do not fully reflect the value of scarcity and so would not provide sufficient incentive for providers to be available when needed. By contrast an Administrative Capacity Market reinforces market signals for plants to be available when needed as providers lose part of their capacity payment (in addition to forgoing energy market revenue) at times of system scarcity.

The second reason why the Administrative Capacity Market is the preferred option is that it does not create additional risk for providers wishing to sell energy forward: under a Reliability Market, by contrast, providers that sell energy forward would be exposed to significant basis risk – whereby they are paid according to the forward price but have a liability to pay the real-time price. For generators to hedge this risk they would likely either cover their position by purchasing financial options when they sell energy forward or they would sell energy into the real-time market and buy financial products to hedge price risk up to that point. However the transition to purchasing financial products is potentially costly, particularly in the implementation phase until appropriate liquid markets emerge.

More detail on the full options appraisal for options mitigating security of supply risks is provided in the Capacity Market Impact Assessment.

The Capacity Market design may need to evolve over time to reflect changing market conditions. This will prevent the Capacity Market being locked into an inefficient or ineffective design as the energy market evolves and improvements in the design of the Capacity Market are identified. Therefore, Government will continue to monitor these design proposals to ensure they are compatible with changing market conditions (e.g. cash out reform) that may occur between now and the first auction.

[3] January 2013 update to CfD IA, available at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/73257/contracts_for_difference_ia.pdf

3 Problem under consideration:

Policy uncertainty ahead of EMR

In the run-up to EMR, when current market conditions prevail, the market failures associated with low-carbon technology, as described in the preceding background section, suggest the market will under-provide low-carbon generation in favour of fossil fuel powered generation, and hence will not deliver an optimal generation mix over the long run. Developers of low-carbon power projects that aim to commission in the reformed market may invest ahead of EMR if they had certain foresight over what EMR will deliver for their projects specifically. Without Government intervention to provide such assurances, the uncertainty remains and the existing market environment prevents sufficient investment in low-carbon generation from materialising.

Developers are, therefore, facing short-term policy uncertainty ahead of 2014 when EMR is implemented. Feedback from industry suggests investors will not take a final investment decision unless they:

- are satisfied that they will be able to access the new market arrangements;
- understand how costs and risks in a reformed electricity market would be quantified and allocated; and
- have foresight of future revenue streams as a result of EMR.

Without specific action these points may not be known until 2014 or later, leading to an investment hiatus in low carbon plant.

The analysis contained in this Impact Assessment suggests that in the presence of such delays, it becomes more expensive to meet HMG’s decarbonisation and energy security ambitions, and there are downside risks of not allowing FID enabling, whereby deployment of some low-carbon projects may be significantly delayed or cancelled altogether.

4 Rationale for intervention to enable early investments:

1. Reduce/remove policy uncertainty

In the run-up to EMR, current market conditions remain. Market failures associated with low-carbon technology suggest the market will under-provide low-carbon generation in favour of unabated fossil fuel powered generation. Developers of power projects that will commission in the reformed market would still invest ahead of EMR if they had foresight over what EMR will deliver.

The rationale for intervention is, therefore, to reduce uncertainty to an acceptable level or remove altogether ahead of EMR implementation thereby overcoming existing market failures, and avoiding Government induced barriers to investment resulting from the launch of the reform programme. Where developers are due to reach FID imminently, and all other elements of the FID process are established, removing this policy uncertainty is expected to have a direct impact on developers' ability to reach a final investment decision and for projects to proceed to time.

2. Ensure that the expected EMR benefits are delivered in the most cost-effective way

Analysis conducted for this Impact Assessment shows that in the absence of an effective FID-Enabling product, delays to low-carbon generation lead to significant carbon costs as unabated fossil fuel plant is deployed sub-optimally in the short term; and it becomes more expensive to meet HMG's decarbonisation ambitions by 2030, as the requirement for decarbonisation becomes concentrated in the mid to late 2020s calling for more expensive low-carbon plant. As such, intervention is called for to deliver the objectives of the wider EMR programme of affordability and security of supply at least cost.

5 Policy Objective:

1. To deliver sufficient certainty to enable developers to make FIDs ahead of EMR

The primary objective of the project is to remove sufficiently the uncertainty created by the development of the EMR CfD regime and so enable final investment decisions in advance of its implementation (expected 2014). It is likely that any effective FID-Enabling product will need to provide comfort on both the strike price and the allocation of risk.

It should be noted that the case for FID-Enabling products for individual projects will be assessed on its own merits through the appropriate Government approvals processes, which will call for a comprehensive value for money and risk appraisal, and ensure that any product offered to developers is consistent with wider Government policy.

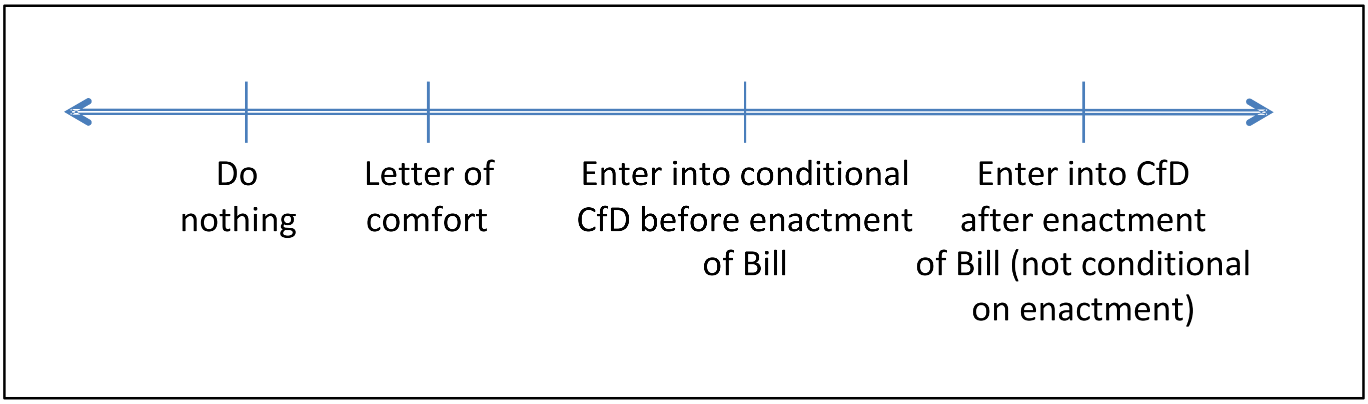
6 Options under consideration:

A range of options, or products, are available to the Government to enable early investment decisions to progress to timetable wherever possible, including those required ahead of implementation of the CfD regime. Options range from do nothing and letters of comfort through to entering into an early CfD with a generator (conditional upon enactment of the Bill if entered into before this occurs).

The actual form of intervention necessary to enable investment will vary by project and developer, and it is impossible to envisage all the projects that may come forward. Furthermore it is impossible, in advance of sufficient engagement with developers, to understand all the project-specific issues that an enabling product should address. As a result, it is not possible to identify a single preferred option for delivery.

However, discussions with developers indicate that for some projects key issues will include certainty on terms of the CfD including the contract duration, risk allocation and strike price (which all have a bearing on financeability). For some developers, anything short of a binding arrangement on these points is likely to be insufficient comfort to enable some developers to commit to a final investment decision ahead of full implementation of EMR.   To secure the objective of enabling final investment decisions, the Bill includes powers for the Secretary of State to give effect to any investment contracts (early CfDs) that he enters into ahead of full implementation of EMR, provided such contracts are laid before Parliament and other conditions are satisfied. (Note that any investment contract entered into before enactment would be conditional on this taking place, and any investment contracts issued would be conditional on securing any necessary Sate Aid approval.)

Figure 3: A range of options available to Government. The product offered will vary by project and developer.



7 Monetised and non-monetised costs and benefits

1. Monetised costs and benefits

Introduction

The costs and benefits presented in the following section compare a world where an effective FID-Enabling product is available, against a world where either the product does not provide sufficient comfort to enable investments to proceed, or no product is available, such as in a do nothing world.

Our analysis shows that there are net welfare benefits to enabling early investments, with the central case showing that there is a net welfare gain of £2.1bn (NPV) to 2030 associated with the introduction of an effective FID-enabling product. This benefit is due to the fact that enabling early investment decisions is likely to deliver a more socially optimal generation mix out to 2030. By offering greater certainty to low carbon investors that are ready to make a final investment decision before EMR has been fully implemented, the Government will help to deliver its decarbonisation ambitions in a more cost-effective way, and mitigate the risks of high impact scenarios from occurring, which carry large welfare costs.

The benefits of introducing FID Enabling are the costs avoided where no credible product is available and projects are delayed or cancelled as a result. Our central case assumes projects will be delayed until 2014, when CfDs become available through the enduring EMR programme, although other scenarios are considered. The main economic drivers behind the costs and benefits associated with delays to the timing of low-carbon investment decisions are as follows:

- **Contemporaneous substitution effects:** Early low-carbon plant is replace by primarily gas-fired CCGT and some unabated coal, leading to higher operating, fuel and carbon costs. Capital costs, however, are reduced as utilisation of existing plant is increased, and cheaper fossil-fuel plant is introduced to maintain minimum capacity margins.
- **Inter-temporal substitution effects:** Early low-carbon plant is replaced by more expensive low-carbon plant in later years. Although discounting and learning bring costs down over time, this is offset by the fact that build rates are constrained on cheaper technologies and low-carbon plant with higher marginal abatement costs are deployed in the late 2020’s in order to meet the same level of decarbonisation in 2030 without FID enabling as with FID enabling.

Our central estimate of a net welfare gain of £2.1bn (NPV) is robust, for example, to changing fossil fuel prices and reductions in demand in the case of lower economic growth. However, it is sensitive to the deployment rate of nuclear. We assume that enabling the first nuclear plant allows subsequent investments to follow in sequence, thereby shifting the entire nuclear deployment curve forward. Technological and regulatory learning from one build to the next brings costs down, incentivising the next project and attracting other players to the market. If, in contrast, we were to assume that early deployment of the first nuclear plant has no impact on subsequent investments in nuclear, the net effects become much lower.

Market intelligence suggests that in the absence of an effective FID-Enabling product, projects could be delayed beyond EMR implementation or cancelled altogether, carrying significant welfare costs. In a world of high international capital mobility and diversified investment strategies, developers may choose to deploy their capital elsewhere ahead of EMR implementation; supply chain constraints could cause developers to lose their position in order books for key manufactured components; and investment decisions could be postponed until such time as this position is recovered; and established positions such as joint venture agreements and other business-critical agreements break down ahead of 2014. These risks are particularly acute when considering nuclear and large renewable projects. There is reason to believe that if early investment in CCS is not forthcoming, its future as part of the generation mix would be very uncertain.

The Modelling

We have used DECC's Dynamic Dispatch Model (DDM) to assess the monetised costs and benefits associated with delays to investments in low-carbon power projects. The main modelling assumptions are as follows[4]:

- A GB renewable electricity ambition of around 110TWh of renewable generation in 2020 is met.
- A decarbonisation ambition of a grid intensity of 100gCO2/kWh by 2030 is met.
- The effects of the capacity mechanism are approximated by assuming enough OCGT build to maintain a de-rated capacity margin of 10%.
- The accounting period for the cost-benefit analysis runs to 2030, which leads to a partial assessment as the full lifetime costs and benefits of some plant are not accounted for. A more detailed discussion of the impacts of this is provided in Annex B.

Furthermore, due to uncertainties over the cost estimates of the early-stage CCS projects and the mix of these projects that will come forward, the impacts of delays to the CCS Commercialisation Programme are not modelled here. We have not, therefore, altered the timing of CCS investments in any of the modelling presented below. We recognise that this introduces some limitations to the analysis of the overall effect of FID enabling on the market.

In order to assess the costs and benefits associated with enabling early investment decisions, it is important to understand what would happen if an effective FID-Enabling product were not available to developers. There is a range of possible outcomes from projects simply delaying until the EMR is implemented in 2014 to much more significant delays through to complete cancellation of the project. We argue that it is most reasonable to assume a conservative approach and assume final investment decisions on projects will only be delayed until 2014 as a central case.

The rationale is as follows:

- There is a credible argument to say that developers are risk averse and will wait until HMG has committed to a strike price and risk allocation under the terms of the CfD before taking final investment decisions.
- There is a risk that projects may be delayed beyond EMR implementation if investment decisions are not taken to timetable. However, looking closely at the evidence, it is difficult to make a realistic assessment of the likely length of delays and the probability of these occuring.
- In the case of nuclear, the impact of slippage could be more significant, and we consider this scenario in more detail below.
- A delay until EMR implementation in 2014 constitutes a 'conservative' counterfactual, in the sense of a minimal delay option, such that if the economic case is made on this basis then the assumption of any further slippage to a given project due to an absence of FID enabling would only serve to strengthen the case[5].

[4] A more detailed presentation of the assumptions is provided in Annex B.

[5] Note, this assumes that delaying low-carbon projects incurs a cost to society. This stylised assumption is supported by the modelling and the reasons for this are discussed in more detail in the cost benefit analysis section.

Given the large impact on the NPV of choosing one counterfactual over another, a full assessment of the counterfactual options and the rationale for selecting our preferred counterfactual is provided in Annex A. The runs in table 1 were designed to offer an assessment of the magnitude of the costs and benefits associated with each outcome.

Table 1: Description of the modelling runs

Run	Description	Rationale
Run 0	Baseline: a world with an effective FID-Enabling product	EMR Baseline with nuclear brought forward by 1 year whilst constraining the overall nuclear deployment to that in the EMR Baseline, and 2 off-shore wind projects added in 2016. These adjustments reflect pipeline data held by the Department and are required to get meaningful results in subsequent runs.
Run 1a	Projects are delayed until EMR (Delay to early nuclear and selected renewable projects, CCS unchanged)	Developers are risk averse and wait until EMR is implemented in 2014, with strike prices and risk allocations known, before taking their FIDs.
Run 1b Preferred counterfactual	Projects are delayed until EMR (Delay to full nuclear deployment and selected renewable projects, CCS unchanged)	As for Run 1a, with the exception that it is assumed that a delay to the first new nuclear build delays subsequent nuclear projects. The deployment profile is that of Run 0 but shifted into the future.
Run 2	Projects are delayed by 3 years (Delay to full nuclear deployment and selected renewable projects, CCS unchanged)	This is a sensitivity on Run 1b.
Run 3	Run 0 with a 5-year delay to nuclear	This run is designed to further our understanding of the impact of delays to nuclear deployment. Capital and supply-side constraints mean that by the time EMR is available, developers are no longer in a position to pursue new nuclear. FIDs are taken with a 5-year delay.
Run 4	Run 0 with no new nuclear build	This run is designed to further our understanding of the impact of delays to nuclear deployment. Industry loses confidence in UK support for new nuclear and does not return for the foreseeable future.
Run 5	Run 1b with low fossil fuel prices	This is a sensitivity on Run 1b, looking at the impact of low fossil fuel prices. The price assumptions used are taken from the DECC fossil fuel price assumptions published in 2011.
Run 6	Run 1b with low demand	This is a sensitivity on Run 1b, looking at the impact of low demand on the uptake of low-carbon generation. The demand profile is consistent with the OBR forecast published in November 2011 and amounts to a drop in demand of 7TWh to 2030.

The Results

Table 2: The modelling outputs – changes of runs 1b and 2 relative to the baseline run 0

Change in welfare NPV 2010-2030, (£m 2010 real)		**RUN 1b**	**RUN 2**
Net Welfare	Carbon costs	-520	-1,113
	Generation costs	-3,541	-7,962
	Capital costs	2,056	760
	Unserved energy	0	0
	Interconnectors	7	1
	Unpriced carbon (appraisal value)	-148	-234
	Change in Net Welfare	**-2,147**	**-8,548**

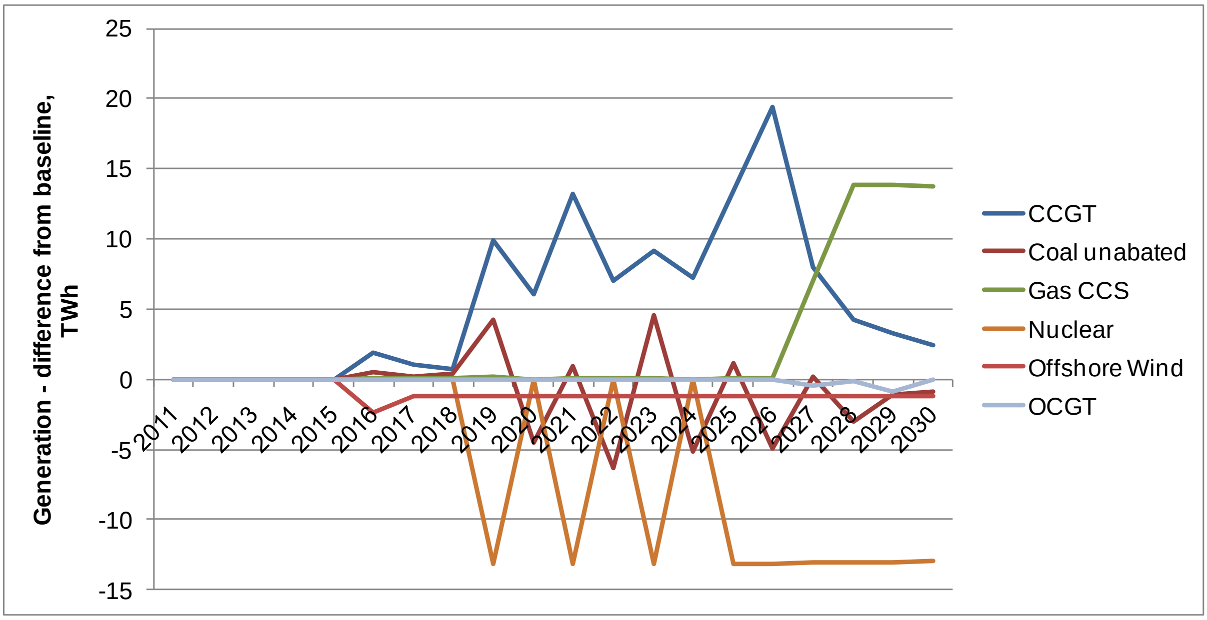
Note: Run 1b is our preferred counterfactual (delay to full nuclear deployment and selected renewable projects, CCS unchanged), Run 2 is a sensitivity on Run 1b with projects delayed by 3 years (delay to full nuclear deployment and selected renewable projects, CCS unchanged). All figures are measured against a baseline run, Run 0 as described in Table 1.

The figures above are measured against the baseline run where FIDs progress to timetable, in other words where an effective FID-enabling product is available. The benefits of introducing FID Enabling are taken as equal to the costs avoided where no FID-Enabling product is available and projects are delayed as a result.

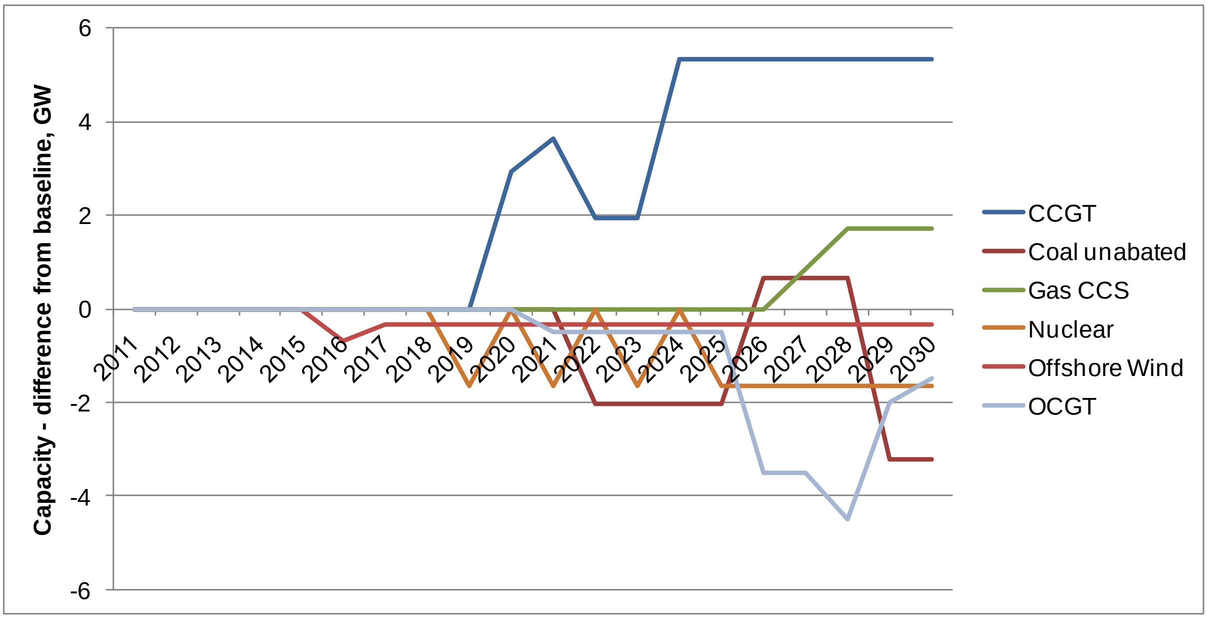
Run 1b and Run 2 together provide the evidence behind the main economic drivers behind the costs and benefits associated with the timing of low-carbon projects. These drivers were described by the contemporaneous and inter-temporal substitutions effects set out in the introduction to this section. These effects are illustrated in the graphs below. The net effect is a net welfare loss where delays are incurred or conversely, a net welfare gain should these projects be enabled through a FID product. In the case of our preferred counterfactual, this is estimated to be in the region of £2.1bn (NPV).

Preferred Counterfactual – Projects are delayed until 2014 (Run 1b)

Graph 1: Run 1b, Generation – difference from baseline in TWh



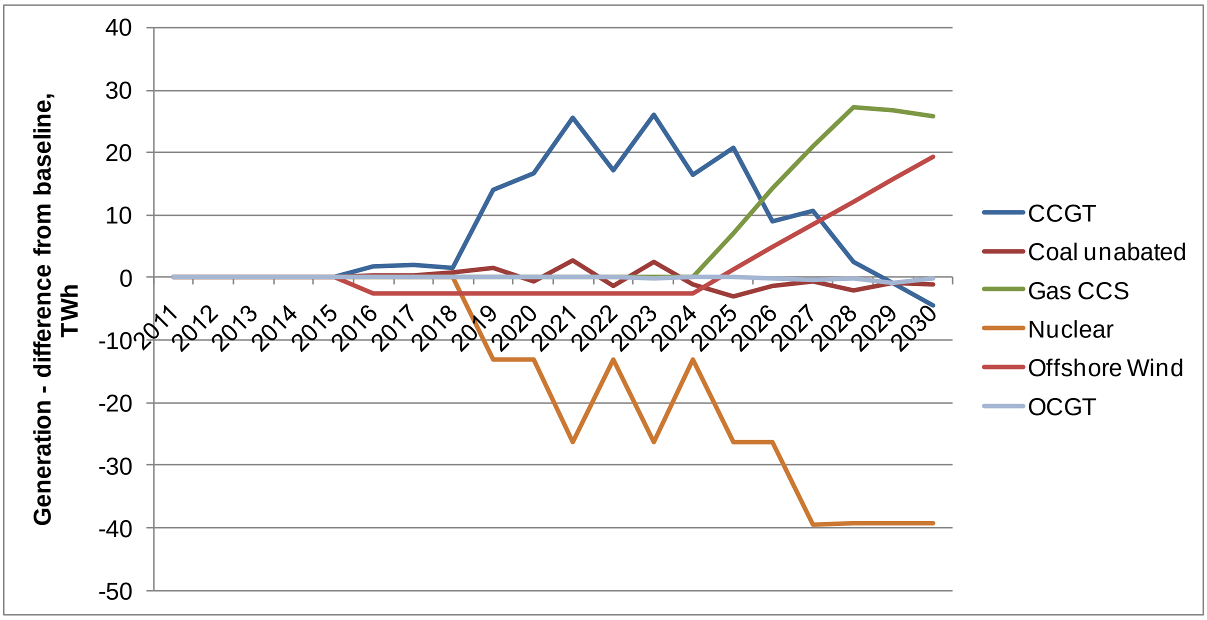
Graph 2: Run 1b, Capacity – difference from baseline in GW



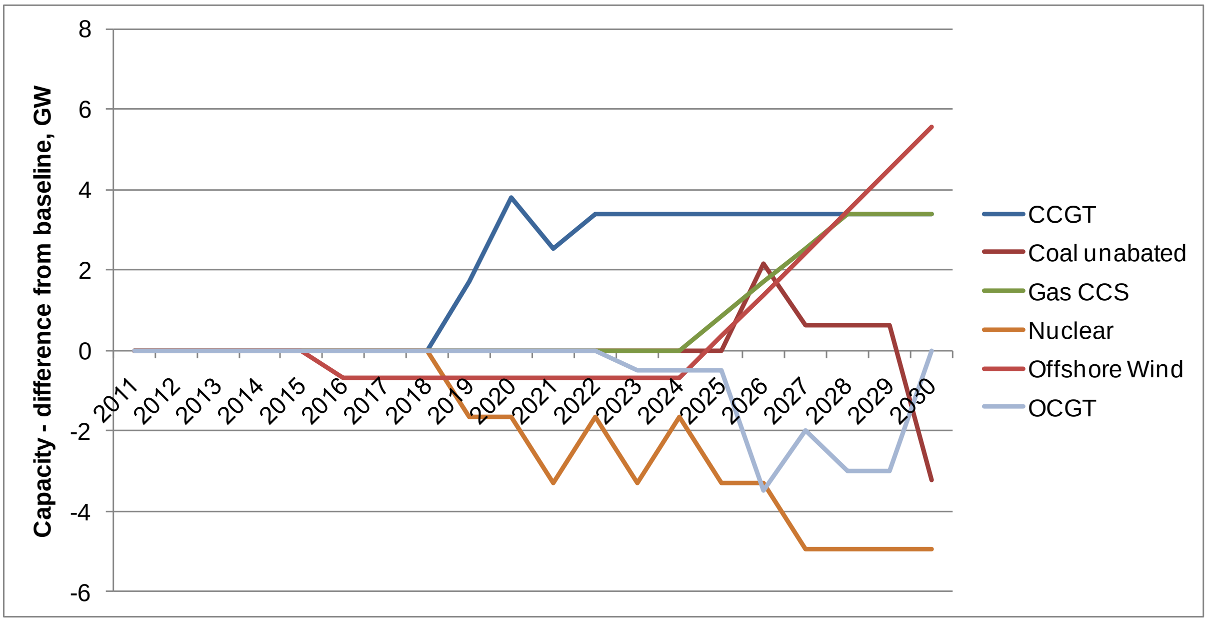
The graphs above show that under our preferred counterfactual scenario, generation from CCGT is higher from 2016 onwards, and there is some unabated coal generation before 2020, as the impact of delayed nuclear and renewables are felt in the form of reduced generation from these technologies. This is the contemporaneous substitution effect. Additional CCGT build is encountered in the late 2020's, however, much of the additional generation is provided by existing plant by increasing load factors and squeezing capacity margins. More gas CCS is required compared to the baseline in the late 2020's in order to meet the 2030 decarbonisation ambition of $100gCO_2/kWh$.

Projects are delayed by 3 years relative to the baseline (Run 2)

Graph 3: Run 2, Generation – difference from baseline in TWh



Graph 4: Run 2, Capacity – difference from baseline in GW



The graphs above show a similar effect to those under the scenario presented in Run 1b, although further delays to low-carbon projects calls for greater substitution into fossil fuel powered plant in order to maintain capacity margins. These graphs illustrate the inter-temporal substitution effects where delays to early low-carbon plant leads to a high concentration of required decarbonisation in the mid to late 2020's in order to meet the decarbonisation ambition. The model predicts significant additional Gas CCS (more than in the preferred counterfactual) and Offshore Wind generation and new build in order to meet the decarbonisation constraint.

This run also demonstrates the benefit of commercial-scale CCS deployment in the mid to late 2020's if other low-carbon technologies suffer delays and deploy at lower levels than might be expected. The value of CCS becomes larger as nuclear and/or renewables are delayed. As such CCS provides a valuable hedge against low deployment of alternative low-carbon technologies.

Sensitivities:

Table 3: Sensitivity analysis

Change in welfare NPV 2010-2030, (£m 2010 real)	RUN 1a Early nuclear only	RUN 1b Preferred Counterfactual	Run 3 Nuclear sensitivity 1	Run 4 Nuclear sensitivity 2	RUN 5 Run 1b with low fossil fuel prices	RUN 6 Run 1b with low demand
Carbon costs	-251	-520	-815	-138	-517	-424
Generation costs	-894	-3,541	-9,434	-11,043	-2,118	-3,530
Capital costs	1,349	2,056	-4,578	-10,694	1,360	1,837
Unserved energy	0	0	0	0	0	0
Interconnectors	-3	7	16	51	-2	11
Unpriced carbon (appraisal value)	20	-148	-59	151	-416	-30
Change in Net Welfare	**222**	**-2,147**	**-14,869**	**-21,672**	**-1,693**	**-2,136**

The NPV is highly sensitive to the deployment profile assumed for new nuclear. Two profiles have been modelled:

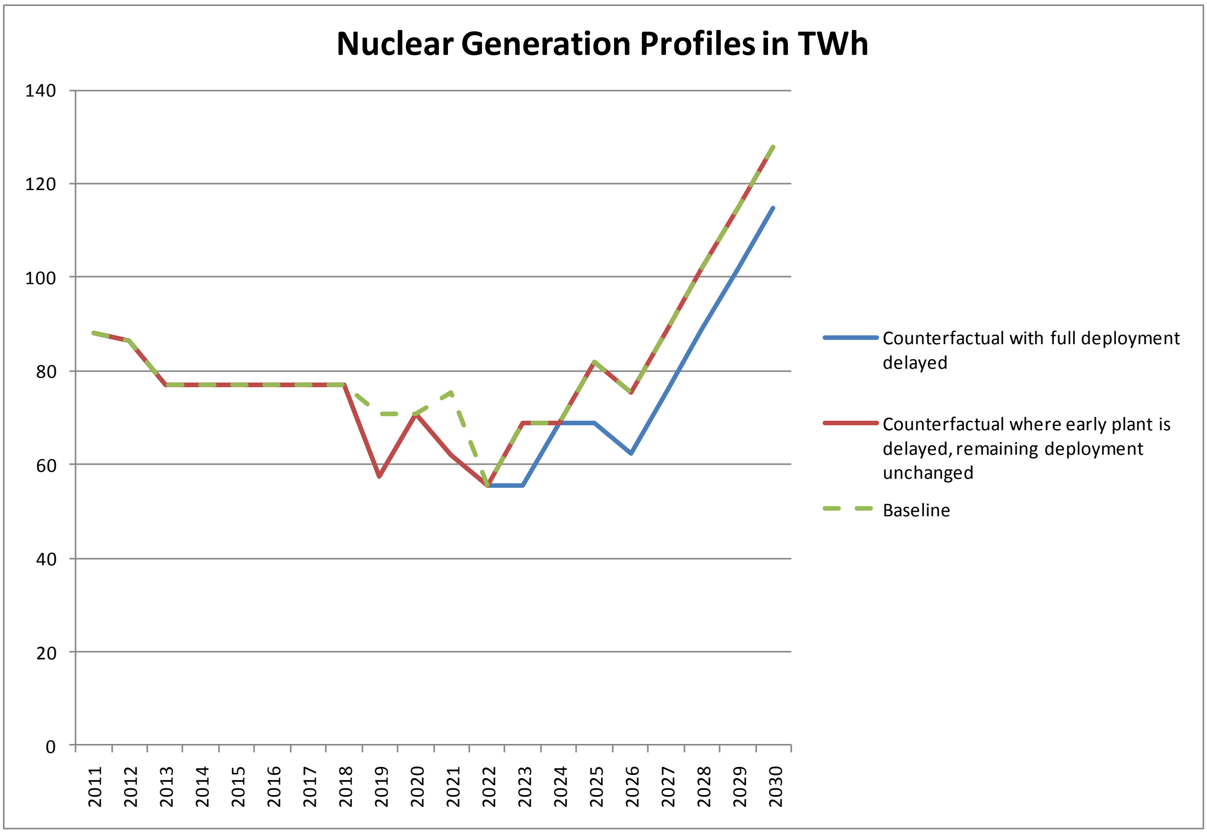
a. Only the first two nuclear plants are incentivised as a result of FID Enabling (Run 1a). The rest of the deployment rate remains consistent with the EMR Central case. In this instance the carbon and generation cost savings are significantly reduced, and indeed are outweighed by the capital costs. It is important to note that CBA results of the magnitude presented above are essentially indistinguishable from zero (i.e. they are well inside any margin of error we could claim for the model).

b. The absence of an FID-enabling product leads to a complete shift to the right of the entire build profile (Run 1b) as illustrated in the graph below. Under this assumption, FID Enabling in the baseline (Run 0) incentivises the first build, and others follow as a consequence. This means that in each year, additional generation from nuclear enters the mix, which introduces significant benefits in terms of generation and carbon cost savings. We have used this as our central scenario.

The Nuclear National Policy Statement[6] lists eight sites as potentially suitable for the development of new nuclear power in the UK. Beyond the proposed development at Hinkley Point C, a further two stations (Sizewell and Sellafield) are expected to submit applications within the following 12-month period, and a third at Wylfa may follow depending on developments. If these projects go ahead, there will be concurrent new build projects from 2015 culminating with reactor construction across 4 sites (and 5 reactors) from 2017. Early investment will be crucial for building the necessary momentum in the sector required to deliver a programme of new nuclear build. Predictability over future projects is key to ensuring that the UK supply chain maintains capacity, and achieves the learning required to secure the benefits from these projects.

[6] http://www.decc.gov.uk/en/content/cms/meeting_energy/consents_planning/nps_en_infra/nps_en_infra.aspx

Graph 5: Nuclear generation profiles

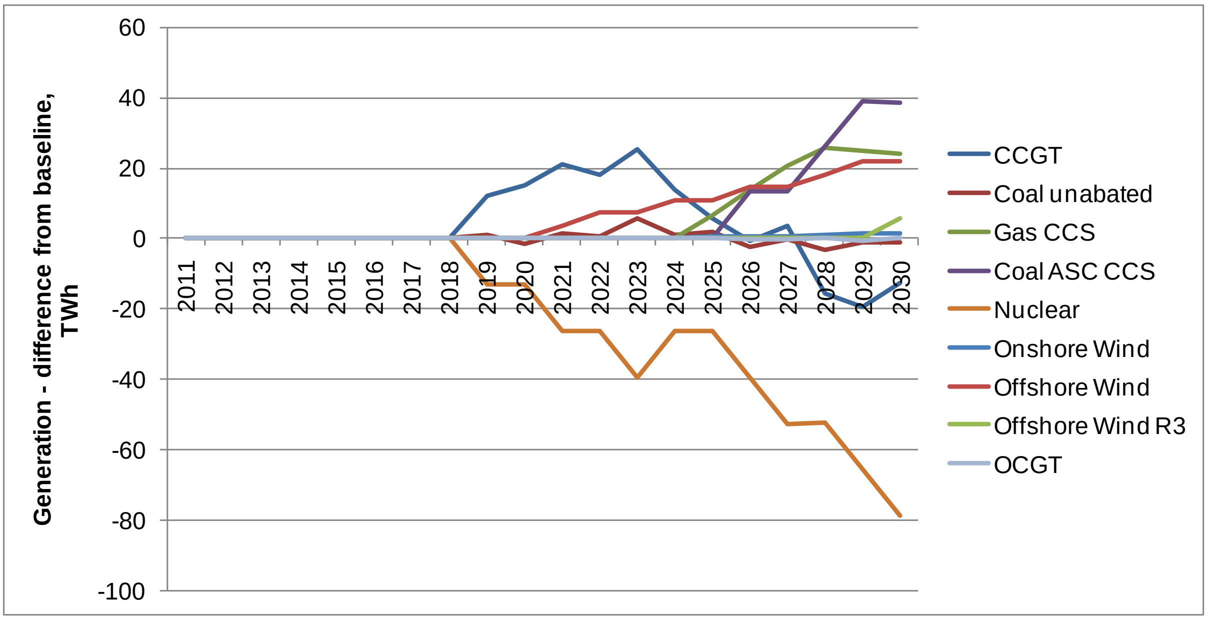


As stated in the introduction to this section, market intelligence suggests that in the absence of an effective FID-Enabling product, projects could be delayed beyond EMR implementation or cancelled altogether, carrying significant welfare costs. The evidence is more compelling for nuclear and we therefore take a closer look at the costs of a more substantial delay to the new nuclear programme.

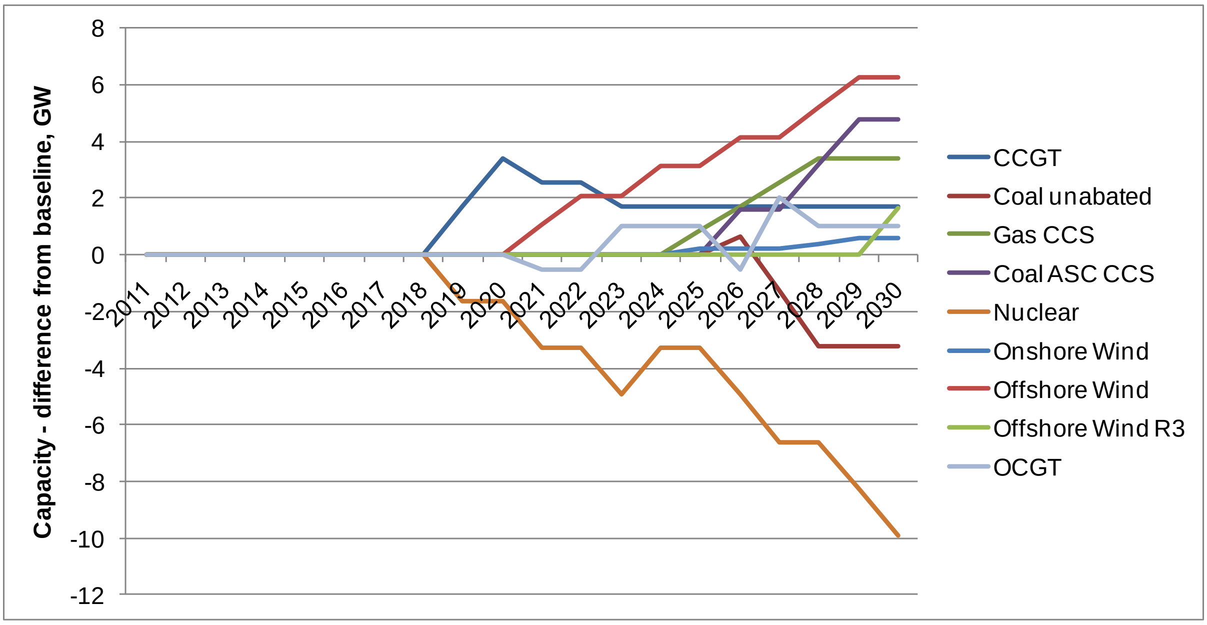
Modelling runs 3 and 4 show that as nuclear deployment is delayed further, the costs increase significantly. A 5-year delay to nuclear deployment (Run 3), leads to a much greater net cost of £15bn, rising to £22bn should the new nuclear programme not go ahead at all (Run 4). These delays lead to a less optimal generation mix with significant increases in generation costs, carbon costs, and capital costs. Generation and carbon costs rise due to higher levels of dispatch from gas and unabated coal plant, and capital costs rise due to a greater reliance on higher-cost renewables and CCS to meet our decarbonisation ambitions.

Nuclear is delayed by 5 years (Run 3)

Graph 6: Run 3, Generation – difference from baseline in TWh



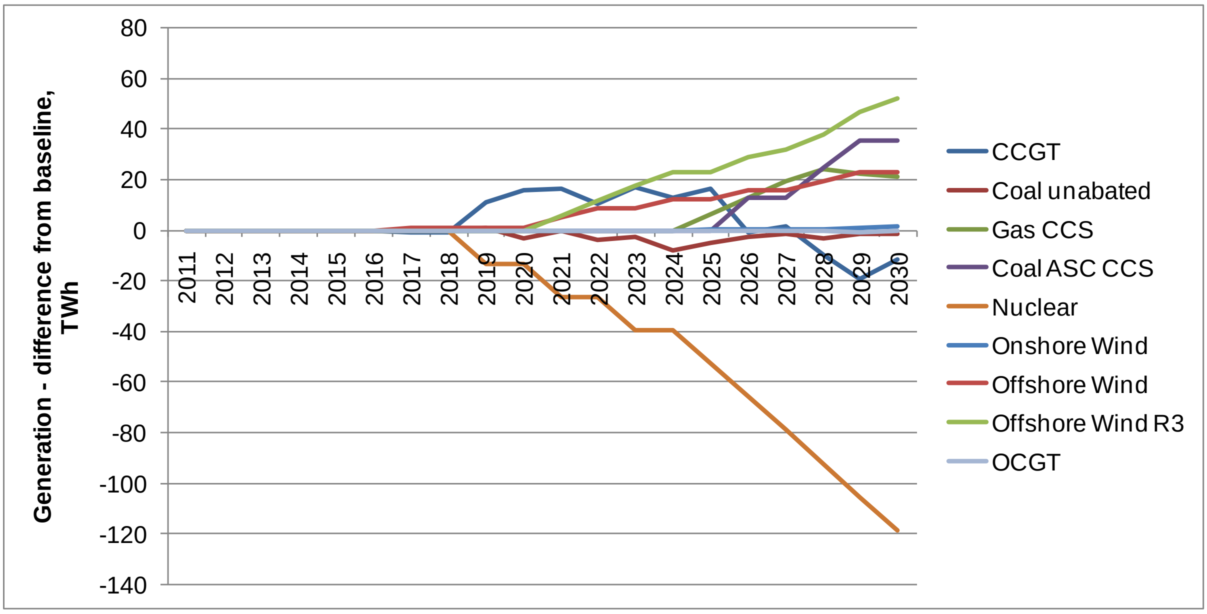
Graph 7: Run 3, Capacity – difference from baseline in GW



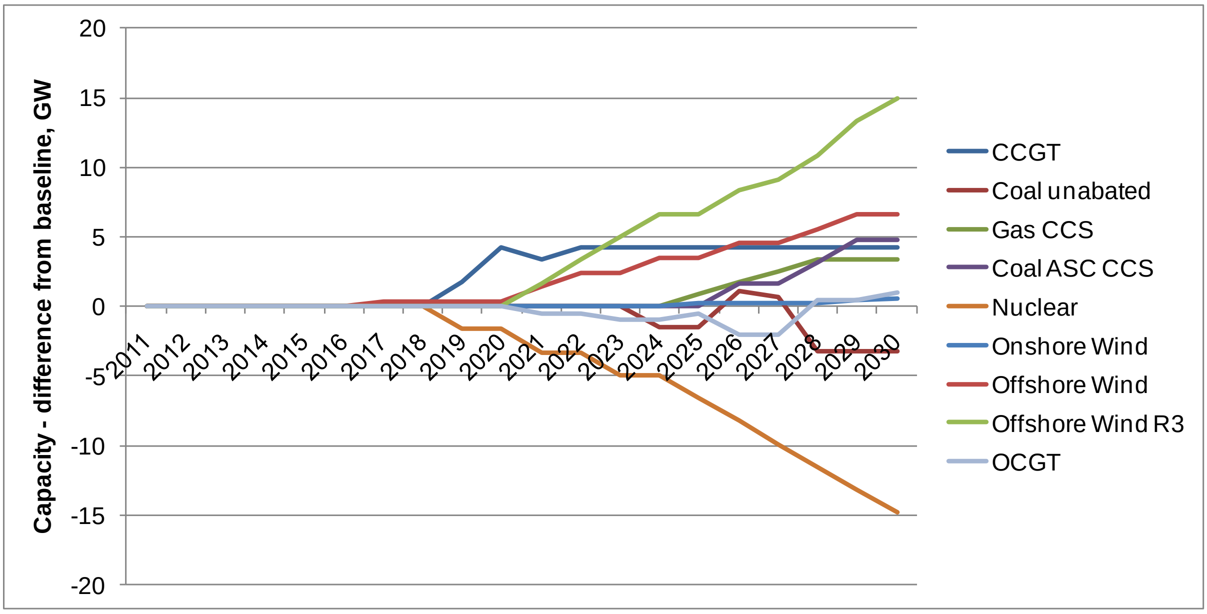
This analysis, as illustrated by the graphs above, further illustrates the benefit of commercial-scale CCS deployment in the mid to late 2020's. As nuclear suffers delays and deploys at lower levels than expected, the value of CCS becomes significant for meeting the decarbonisation ambition. As such CCS provides a valuable hedge against low deployment of alternative low-carbon technologies.

No nuclear (Run 4)

Graph 8: Run 4, Generation – difference from baseline in TWh



Graph 9: Run 4, Capacity – difference from baseline in GW

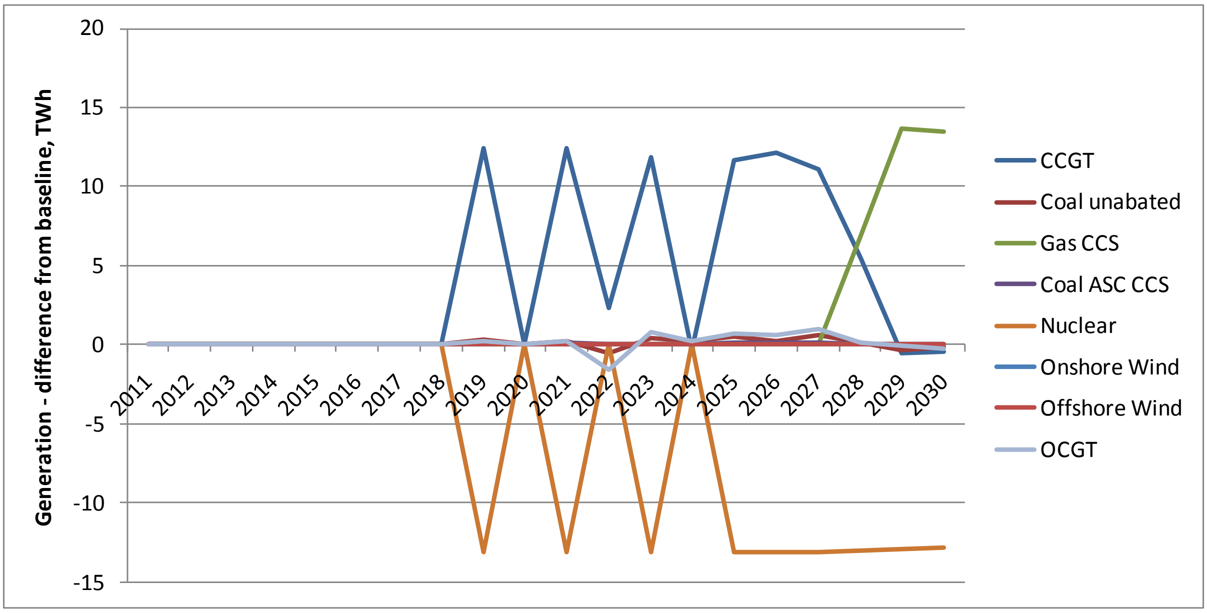


The graphs above show that as the new nuclear programme is cancelled, gas and some unabated coal generation is necessary in the late 2010s and early 2020s, and a mix of more expensive low-carbon technologies is deployed throughout the 2020's. The role of CCS in achieving the Government's decarbonisation ambition is increased as less nuclear is available.

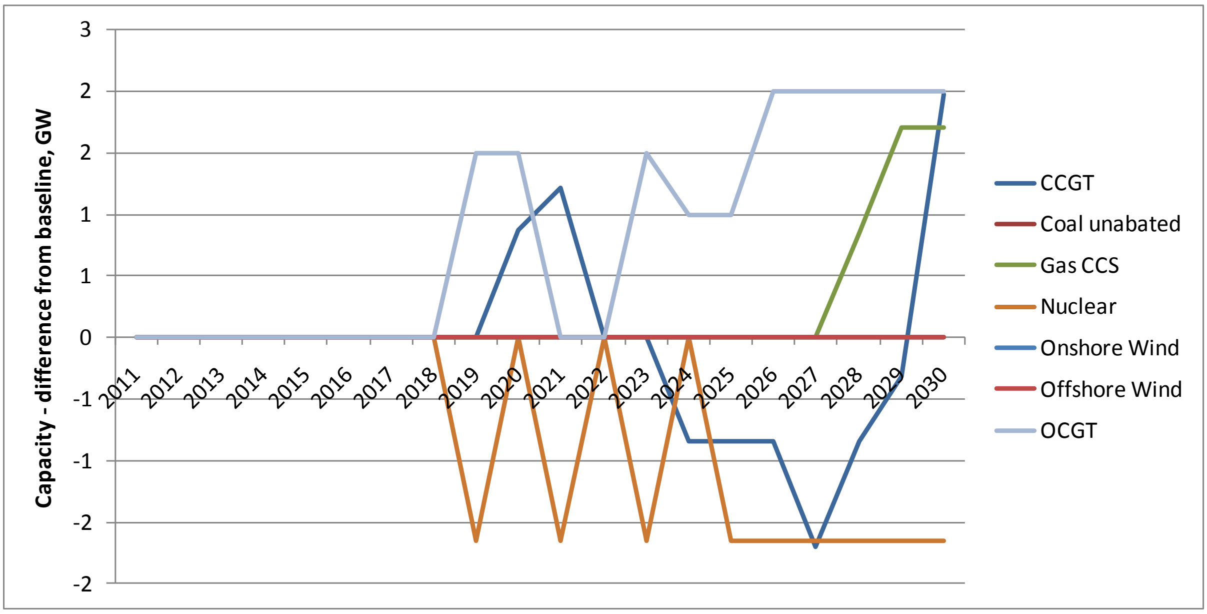
Low fossil fuel prices (Run 5)

Run 5 uses DECC's low fossil fuel price assumption, published in October 2011. Under this scenario, gas is favoured to a greater extent compared to the central case, due to the relative price of gas and coal assumed in the price projections. This leads to very low coal generation after the first few years, and early closures of existing plants.

Graph 10: Run 5, Generation - difference from baseline with low fossil fuel prices



Graph 11: Run 5, Capacity - difference from baseline with low fossil fuel prices



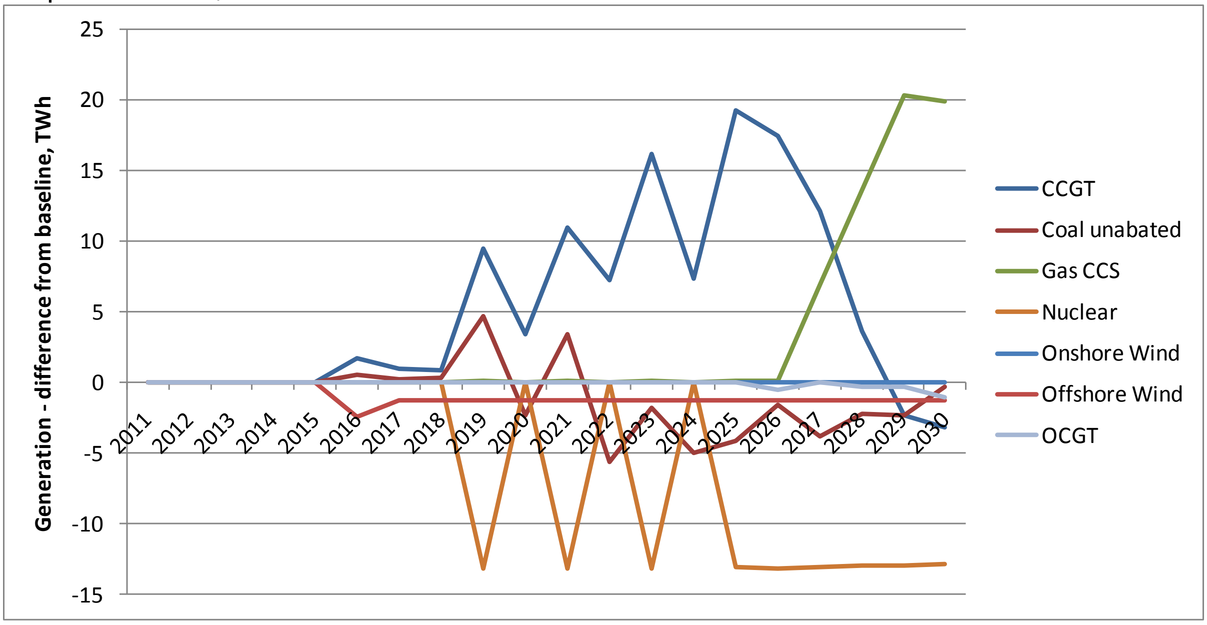
Compared to the situation under central fossil fuel price assumptions, assuming low fossil fuel prices means the NPV is reduced from £2.1bn to £1.7bn. This is almost exclusively because of the reduction in the difference in generation costs due to the decreased gas price. Instead of a difference of £3.5bn in generation costs, the difference is only £2.1bn. This reduction in benefits for FID Enabling is partly offset by the different capital costs in the two runs: in the counterfactual with low fossil fuel prices, the lack of early nuclear coupled with closure of existing coal plants leads to earlier higher build of OCGT plant as illustrated above.

Low demand (Run 6):

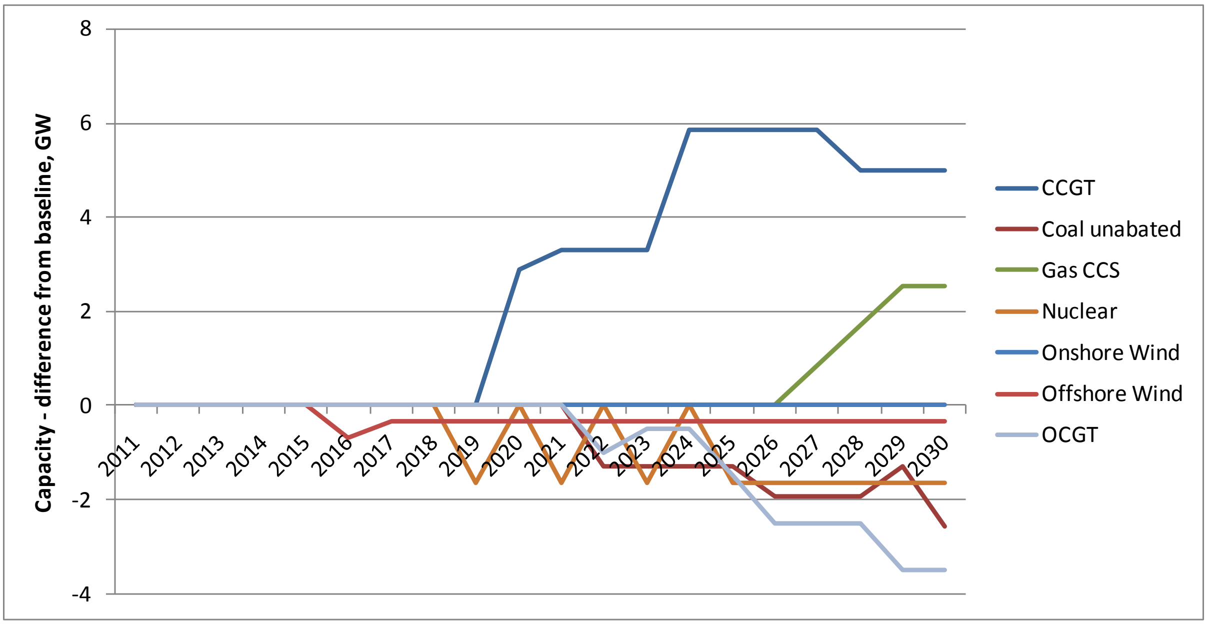
Run 6 with lower demand is based on the Office for Budget Responsibility (OBR) November 2011 GDP projections. In calculating the demand profile, we assume that household demand is inelastic with respect to GDP, but that other, non-domestic demand varies with an elasticity of one. This gives a demand reduction of approximately 8TWh to 2030.

The cost-benefit analysis results are very similar to those from the central demand runs.

Graph 12: Run 6, Generation - difference from baseline with low demand



Graph 13: Run 6, Capacity - difference from baseline with low demand

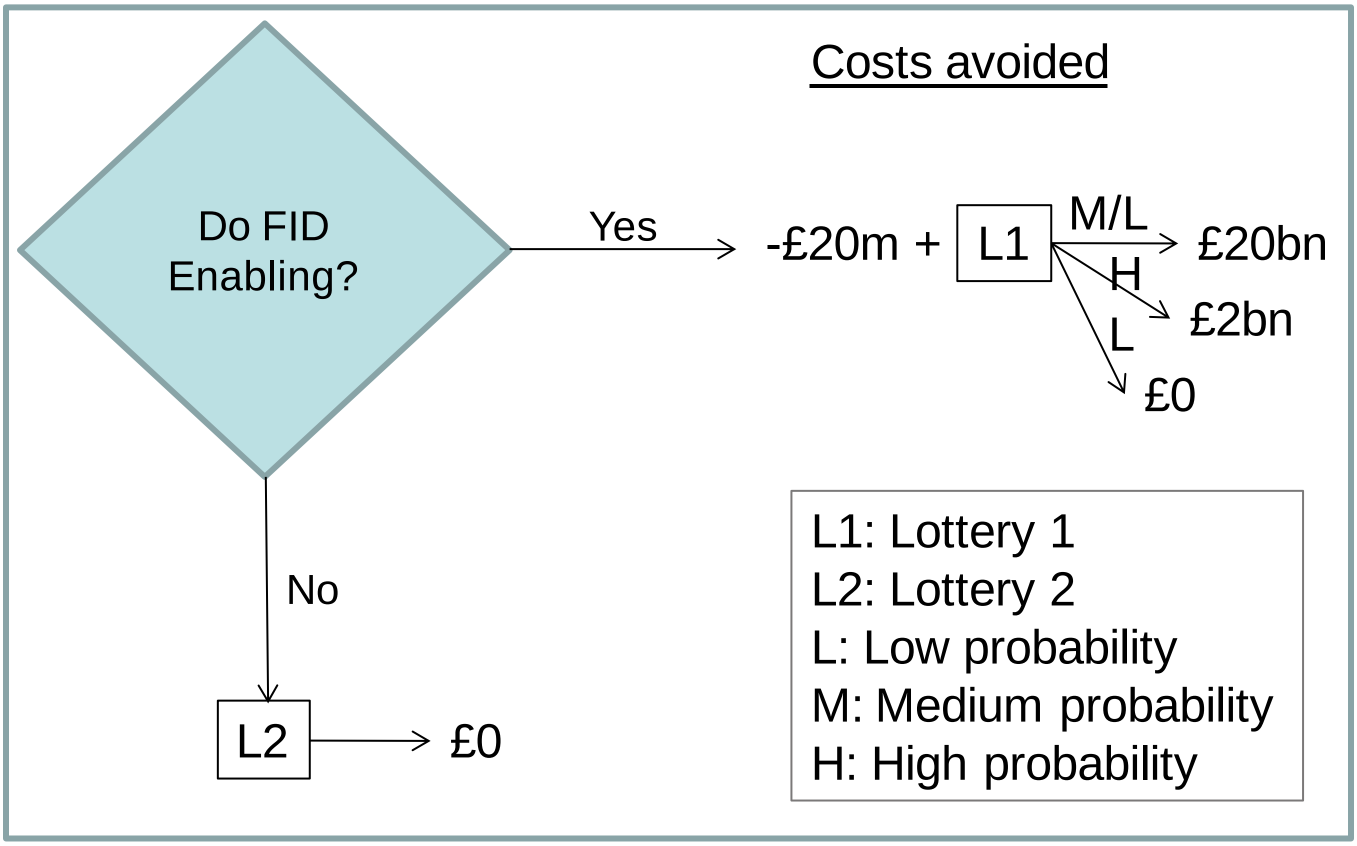


The graphs above show that as under central demand assumptions, under low demand assumptions the generation from CCGT is higher from 2016 onwards in the counterfactual than in the basline, and early on there is some additional unabated coal generation. This reflects the impact of delayed nuclear and renewables, felt in the form of reduced generation from these technologies. More gas CCS is required compared to the baseline in the late 2020's in order to meet the 2030 decarbonisation ambition of 100gCO2/kWh.

A probabilistic view

The monetised cost-benefit analysis presented above shows that there is a range of possible outcomes associated with the introduction of FID Enabling. These outcomes change with changing counterfactuals and it is clear that the assumption on what we believe a world without FID Enabling looks like is critical to the final NPV. Other assumptions are also important, such as the deployment rate of nuclear for instance. We have selected a preferred or more likely counterfactual, run 1b, and explained why we believe this is a credible outcome. This delivers benefits to FID Enabling in the region of £2.1bn, however, we recognise that other outcomes are possible. Although it is difficult to assess the likelihood of each outcome from occurring the Figure 3 below attempts to summarise all the results presented in this section and offer a rationale for progressing with FID Enabling which is robust to these differing views.

Figure 4: A probabilistic view of FID Enabling where outcomes are costs avoided



This diagram illustrates that by progressing with FID Enabling, HMG incurs admin/programme costs of £20m, but then faces an uncertain outcome or “lottery” which has a strong positive skew. We have illustrated just three possible outcomes, a minimum, a maximum and our preferred or more likely counterfactual, however, there may be a continuum of outcomes across the range. The range reflects different counterfactual assumptions, different input parameter assumptions, such as build rates, fossil fuel prices, demand levels, cost assumptions etc. It also reflects the fact that negotiations do not offer a certain outcome.

The probability distribution is difficult to estimate, however, given the size of the pay-offs, the expected value of lottery L1 is expected to exceed £20m, thereby offering a strictly positive outcome in expected NPV terms to proceeding with FID enabling.

2. Non-monetised Costs and Benefits

These include:

- The impacts of bringing forward low-carbon electricity generation projects before 2014 on the costs of electricity generation beyond 2030 are not included in the monetised CBA above. Whilst these impacts would be considerably discounted in the NPVs, they could nevertheless be significant as: a) the projects in question could be generating some years after 2030; and b) there could be long-term knock-on impacts of an investment hiatus on the low-carbon generating capacity deployment profiles.
- The impacts on wider electricity system costs, e.g. relating to transmission and distribution network investment, are not considered in the monetised CBA.
- There would also be impacts on the wider macroeconomy through changes to electricity prices. For example, if electricity prices were to rise, this would reduce the real income of final consumers, whilst increasing business costs and hence the prices of goods and services, reducing international competitiveness. The reverse would be true if electricity prices were to fall.

The option value of CCS in the late 2020's:

- The analysis conducted above indicates that CCS has a role to play in the generation mix in the second half of the 2020s, alongside nuclear and renewables, in achieving decarbonisation of the electricity sector at least cost.
- Furthermore, the role and value that CCS plays in the electricity market will be larger if nuclear and/or renewables do not achieve the ambitious roll out rates envisioned. Providing assurance through FID Enabling therefore strengthens the prospects of achieving commercial-scale CCS in the late 2020s, thereby providing a valuable hedge against low deployment of alternative low-carbon technologies.

The option value of running the FID-Enabling process:

- By seeking powers through the Energy Bill to allow delivery of FID-Enabling products, HMG is signalling its commitment to supporting early low-carbon electricity generation projects via the EMR framework. This is likely to keep developers engaged in the FID-Enabling process, thereby providing HMG with the option to agree terms and conditions with the developers, if these are acceptable to both parties, or walk away from the process if there is no/insufficient common ground.

The value of early information (e.g. cost and price discovery process):

- The working assumption is that Government and business would incur relatively small administrative costs as a result of HMG engaging early with developers through the FID-Enabling process. This is likely to hold true for large projects where there are very few players in the market, and where under the enduring regime a bilateral price discovery process conducted by HMG will also be required.
- The information gathered through the FID-Enabling process (which may on a case-by-case basis include bilateral negotiations on strike price) for individual projects can be used to inform similar discussions with other developers, and can help to shape the CfD design with 'live' input from one or more developers.

Benefits to supply-side industries:

- The Namtec 2009 report suggests there is significant demand-led expansion potential in the UK for nuclear supply-side industries. This would cover project management, civil construction, supply and manufacture of a large number of components, and all aspects of the operation and decommissioning. The Arup 2011 report[7] on Renewable energy deployment has identified significant deployment potential in the UK, which it claims should allow the achievement of UK Government targets. Previous reports (TINA, 2012; AEAT, 2013)[8] have highlighted the value of CCS to the UK supply chain, with opportunities in construction, components and materials but also know-how based services including consulting, engineering, project management, procurement and financial and legal services. Early investment in each of the technologies (renewables, nuclear and CCS-equipped

[7] Review of the generation costs and deployment potential of renewable electricity technologies in the UK, Arup 2011 http://www.decc.gov.uk/assets/decc/11/consultation/ro-banding/3237-cons-ro-banding-arup-report.pdf

[8] http://www.lowcarboninnovation.co.uk/working_together/technology_focus_areas/carbon_capture_and_storage/ https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/140108/AEA_Technology_reprort_-_Assessing_the_Domestic_Supply_Chain_Barriers_to_the_Commercial_Deployment_of_Carbon_Capture_and_Storage_within_the_Power_Sector_-_FINAL.pdf

generation) under consideration will promote jobs in these areas, and kick-start the 'learning from doing' process that will bring technology costs down over time.

- Additional investment in the UK supply chains for low-carbon technologies could lead to increased economic activity overall, as whilst it may displace economic activity elsewhere in the economy, there is currently spare capacity in the economy and there may be a 'productivity premium' associated with some of these sectors. Furthermore, where Foreign Direct Investment is attracted and R&D funding is increased, there may be spillover benefits for UK society.

Annex A: Defining the Counterfactual

Understanding what a world without FID Enabling might look like is a difficult task and deserves to be considered in detail. Different counterfactuals will yield different social NPVs when considering the policy options, and selecting the most appropriate counterfactual is a key building block in the economic analysis.

In the absence of FID Enabling, there is a range of possible outcomes for projects that suffer from the failures (regulatory/market/etc.) previously identified, and that require a CfD for investments to be pursued. These outcomes are:

a) Final investment decisions progress to timetable.
b) Final investment decisions are postponed until the EMR CfD regime has been established, there is certainty on the strike price, risk allocation and other key terms of the CfD and CfDs can be entered into (signed) by the counterparty body.
c) Final investment decisions are postponed until HMG has committed to a strike price and risk allocation under the terms of the CfD, however, supply-chain bottle necks, capital constraints, or other negative investment signals, lead to projects being delayed by some longer period of time, say 3/5 years.
d) A lack of engagement leads developers to lose confidence in HMG's support, and investments are cancelled altogether.

Outcome a:
Where a project is eligible for FID Enabling but a FID-Enabling product is not available, the final investment decision would only progress to timetable under artificial conditions of perfect foresight from the developer, or where the developer's appetite for risk is sufficiently high, that they are willing to commit capital to a project that has large uncertainty over its future revenues. It is our assessment that this is highly unlikely, and this counterfactual is therefore not considered further.

Outcome b:
This outcome is likely where projects are due to reach FID in the run up to EMR being implemented. It should be noted, however, that developers may perceive the absence of a credible FID-Enabling product as a signal that HMG lacks the political consensus to launch EMR as it has previously been announced, or lacks commitment to a particular project or technology or considers that that successful implementation of the EMR programme is threatened. It is our assessment, therefore, that in the absence of a credible FID-Enabling product, developers may take their investment elsewhere, leading to projects being mothballed for more significant periods of time. There is a risk therefore that option 1b becomes a 1c or 1d as described below.

Outcome c:
This outcome is likely where developers perceive the absence of a credible FID-Enabling product as a signal that HMG lacks the political consensus to launch EMR as it has previously been announced, or lacks commitment to a particular project or technology, or considers that successful implementation of the programme is threatened. Furthermore, if the timing and concentration of capital, supply-side infrastructure, and labour skills are critical, then there is a risk that some projects may be unable to proceed at the point that EMR has been announced, regardless of the will of the developer. Large energy investments are lumpy and it may be that where an investment decision is shelved today, it may not be revisited until some later date.

Outcome d:
This outcome is likely where developers perceive the absence of a credible FID-Enabling product as a signal that HMG lacks the political consensus to launch EMR as it has previously been announced, or lacks commitment to a particular project or technology, or considers that successful implementation of the programme is threatened. Under this scenario, developers lose confidence in HMG's support for their particular technology or project, and commit capital, skills and labour elsewhere, possibly outside of the UK. This outcome is more likely for some technologies, such as nuclear, where regulatory learning and compliance is a costly process, creating a barrier to re-entry into a market once knowledge and expertise has been developed elsewhere.

The preferred counterfactual

We have chosen Outcome b, an investment hiatus until EMR CfDs are able to be signed, as our preferred counterfactual. The rationale is as follows:

- Outcome a is discarded on the basis of the arguments outlined above.
- There is a credible argument to say that developers are risk averse and will wait until HMG has committed to a strike price and risk allocation under the terms of a CfD before taking final investment decisions.
- We have highlighted risks of projects slipping from Outcome b to Outcomes c/d, however, looking closely at the evidence, it is difficult to make a realistic assessment of the likelihood of these risks being realised.
- In the case of nuclear, the impact of slippage to options c/d is considered more significant. In order to understand the magnitude of the costs, further analysis has been conducted for the purpose of this economic assessment and can be found in the cost-benefit analysis section of this Impact Assessment.
- Outcome b constitutes a 'conservative' counterfactual, in the sense of a minimal delay option, such that if the economic case is made on this basis then the assumption of any further slippage to a given project thereafter only serves to strengthen the case[9].

[9] Note, this assumes that delaying low-carbon projects incurs a cost to society. This stylised assumption is supported by the modelling and the reasons for this are discussed in more detail in the cost benefit analysis section.

The DDM is a partial equilibrium model, which aims to match supply and demand at every point in time in the electricity market. It therefore does not include analysis of the labour market and supply-side industries for example. The DDM cost benefit analysis does not, therefore, constitute a full appraisal, and should be considered alongside the qualitative analysis of the non-monetised costs and benefits.

The cost-benefit analysis provided by the model is a discounted cash flow calculation. Using the social discount rate of 3.5%, the model assesses the present value of the stream of costs and benefits to 2030 associated with the generation mix under different policy scenarios. The results are offered relative to a baseline.

Included in the calculation are: carbon costs, calculated at the social value of carbon; generation costs, defined in the DDM as fixed and variable operating costs, such as maintenance costs and fuel consumption; capital costs - these are the overnight costs for adding to the stock of power generating plant; the cost of unserved energy; and any costs associated to importing electricity via interconnectors.

The results are influenced by three targets or ambitions:

- Meeting a GB renewable electricity ambition of 110TWh of renewable generation in 2020.
- Meeting an assumed decarbonisation ambition of a grid intensity of 100gCO2/kWh by 2030.
- Keeping the de-rated capacity margin above 10% by using a strategic reserve capacity mechanism that builds OCGT.

As the central feature of the EMR programme, and therefore of the FID-Enabling product, CfDs are used to bring on low-carbon plant in such a way that the renewables and decarbonisation targets listed above are met cost-effectively. New OCGT plants are built to maintain a de-rated capacity margin of around 10%.

The accounting period for the cost-benefit analysis runs to 2030. This cut-off introduces discrepancies in the CBA as the full lifetime costs and benefits associated to some plant are not accounted for. It should be noted that the effect of this can be both beneficial and detrimental to the results as presented. The regulatory landscape, and key assumptions on commodity prices and electricity demand become increasingly uncertain between 2030 and 2050. Furthermore, a similar issue would arise in 2050 in an extended CBA exercise. Given that the impact of a 2030 cut-off is uncertain, and developing an extended CBA may introduce further inaccuracies, we have kept to an accounting period that runs to 2030 in our analysis.

Input assumptions for the DDM modelling:

- The runs use the central fossil fuel and carbon price projections published in Autumn 2011
- The data[10] for new plant is from the PB Power (non-renewable) and Arup (renewable) studies published in July 2011.
- Hurdle rates for investment decisions are derived primarily from the Oxera report for the CCC from March 2011, and for Round 3 offshore wind from the Arup study. Wind and biomass technologies have been modelled using a simple supply curve to take account of the range of costs that apply to these technologies.
- A number of other key assumptions (such as the characteristics of existing plant, load curves by sector and data on wind speeds) were provided by Pöyry.
- Electricity demand is derived from that calculated by the DECC Energy and Emissions Model (published in Autumn 2011), and takes into account all firm and funded (demand-side) policies.

[10] These datasets include information on capital cost, construction time, economic lifetime, availability, efficiency, variable operating costs and fixed costs.

Annex C: Detail of results by modelling run

Change in welfare NPV 2010-2030, (£m 2010 real)	Baseline: EMR baseline with minor changes to renewables	RUN 1a: 1 year delay, early nuclear only, no CCS shift	RUN 1b: Preferred Counterfactual 1 year delay, complete nuclear shift, no CCS shift	Run 2: 3 year delay, no CCS shift	Run 3: Nuclear sensitivity 1	Run 4: Nuclear sensitivity 2	RUN 5: Run 1b with low fossil fuel prices	RUN 6: Run 1b with low demand
Carbon costs	211	-251	-520	-1,113	-815	-138	-517	-424
Generation costs	849	-894	-3,541	-7,962	-9,434	-11,043	-2,118	-3,530
Capital costs	-1,895	1,349	2,056	760	-4,578	-10,694	1,360	1,837
Unserved energy	0	0	0	0	0	0	0	0
Interconnectors	11	-3	7	1	16	51	-2	11
Unpriced carbon (appraisal va	-98	20	-148	-234	-59	151	-416	-30
Change in Net Welfare	**-921**	**222**	**-2,147**	**-8,548**	**-14,869**	**-21,672**	**-1,693**	**-2,136**

Baseline:
- Same as EMR central, except first nuclear build is brought forward by one year, and some offshore R2 build (2 plants, which is not captured in the Arup build rates) is imposed in 2016. These adjustments reflect pipeline data held by the Department and are required to get meaningful results in subsequent runs.
- Total system costs (changes in which are referred to as net welfare changes) are very similar to the standard baseline.

Run 1a: 1 year delay, early nuclear only, no CCS shift
- First new nuclear build is delayed by a year relative to baseline, but overall build catches up from 2022. Offshore wind build in 2016 is delayed by one year. There is no change to CCS from the baseline.
- Net welfare impacts: Relative to baseline, generation and carbon costs are slightly increased, however this is more than compensated for by a decrease in capital costs. Overall this leads to a change in welfare NPV relative to baseline of +£0.2bn. This decrease in capital costs is because the reduction in nuclear capacity in the early 2020s leads to more CCGT staying on the system, and consequently significantly lower build of new CCGTs. In addition there are discounting benefits from moving the build of the first two plants back a year. The consumer surplus is positive because of the reduction in low carbon payments (mostly from reduced ROC payments, due to the lower levels of offshore deployment).

Run 1b: Preferred counterfactual: 1 year delay, complete nuclear shift, no CCS shift
- The entire nuclear build programme is shifted back by a year relative to baseline, so nuclear capacity is lower in every year from 2025. Offshore wind build in 2016 is delayed by one year. There is no change to CCS from baseline (the FID enabling impacts on CCS are NOT included in this run).
- Net welfare impacts: Because there is less nuclear capacity in several years, there is a significant increase in generation costs as gas use is increased. This is not offset by the reduction in capital costs arising from the loss of one nuclear plant. The NPV is -£2.1bn. The wholesale price is slightly lower on average (as the overall capacity is slightly higher on average, leading to a reduced value of capacity), leading to an increased consumer surplus.

Run 2: 3 year delay, no CCS shift
  - The entire nuclear build programme is shifted back by a 3 years relative to baseline, so nuclear capacity is lower in every year. Offshore wind build in 2016 is delayed by 3 years. There is no change to CCS from baseline.
- Net welfare impacts: Because there is less nuclear capacity in all years, there is a very significant increase in generation costs and carbon costs as gas use is increased. This is not offset by the reduction in capital costs arising from the loss of three nuclear plants. the NPV is -£9bn. Subsidy payments are higher because of the need to incentivise more gas CCS and offshore wind to hit the 2030 target. This leads to a reduction in the consumer surplus.

Run 3: nuclear sensitivity 1
- Nuclear build delayed by five years (to 2024).

- Net welfare impacts: While generation costs are increased compared to Run 2, capital costs are reduced, leading to a change in welfare NPV relative to baseline of -£15bn. Although unabated gas generation compared to Run 2 is decreased, overall fossil fuel use is higher, because of the large increase in CCS generation. In addition CCS plants have significant non-fuel costs associated with CO2 transport that are included in the generation costs. Capital costs are reduced compared to Run 2 because of the availability of CCS which reduces the deployment of R2/3 offshore wind that is required to meet the 2030 target.

Run 4: nuclear sensitivity 2
- No new nuclear build, otherwise the same as Run 0.
- Net welfare impacts: While capital and generation costs are higher than Run 3, carbon costs are significantly lower, as earlier deployment of low carbon technologies is required to make up for the lack of new nuclear build. The overall change in welfare NPV relative to baseline is -£22bn. Generation costs are increased relative to Run 3 even though there is similar gas/coal generation, because of increased Operations and Maintenance costs of offshore wind. Capital costs are higher due to the high cost of offshore wind (even with the deployment related cost reductions that are built into this run).

Run 5: Run 1b with low fossil fuel prices
- Run 1b with low fossil fuel price projection from Autumn 2011 fossil fuel price assumptions used and measured against a baseline with similar assumptions. Note that the low scenario is very gas favouring compared to the central. This leads to very low coal generation after the first few years, and early closures of existing plants.
- Net welfare impacts: Comparing this run with the original 1b, shows that the NPV is reduced. This is almost exclusively because of the reduction in the difference in generation costs due to the decreased gas price. Instead of a difference of £3.5bn in generation costs, the difference is only £2.1bn. This reduction in benefits for FID is partly offset by the different capital costs in the two runs: the lack of early nuclear coupled with closure of existing coal plants leads to earlier higher build of strategic reserve.

Run 6: Run 1b with low demand
- Run 1b with lower demand, based on OBR November 2011 GDP projections. It is assumed that household demand is inelastic with respect to GDP, but that non-domestic demand varies with an elasticity of one. This gives a demand reduced by around 8TWh in the long run.
- Net welfare impacts: CBA results are almost identical to those from the central demand runs.