Title: **Implementation of Directive 2013/30/EU on the safety of oil and gas operations and on updating UK oil and gas legislation** IA No: 0088 Lead department or agency: **Health and Safety Executive** Other departments or agencies: **Department of Energy and Climate Change** **Department for Transport** **Department for Environment Food and Rural Affairs**	**Impact Assessment (IA)** **Date:** 11th December 2014 **Stage: Final** **Source of intervention:** European **Type of measure:** Secondary Legislation **Contact for enquiries:** Jim.Neilson@hse.gsi.gov.uk Irene.Thomson@decc.gsi.gov.uk
Summary: Intervention and Options	**RPC Opinion: GREEN**

Cost of Preferred (or more likely) Option

Total Net Present Value	Business Net Present Value	Net cost to business per year (EANCB on 2009 prices)	In scope of One-In, Two-Out?	Measure qualifies as
-£196.21m	-£193.44m	£17.09m	No	N/A

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

In 2011, the EC published proposals for a direct-acting European Regulation to strengthen the EU Offshore oil and gas regulatory system. The UK argued strongly for a Directive, to enable it to build the new requirements into its existing world-class regime. This was successful, and the Directive, which must be implemented by 19th July 2015, contains requirements relating to licensing, environmental protection and oil spill response, and liability in addition to safety matters, and therefore requires a coordinated implementation approach between the relevant Government departments. Intervention is necessary to establish an offshore competent authority (CA), to amend existing legislation or implement new provisions and to introduce administrative measures to fully transpose the Directive within the stated time-frame. Offshore oil and gas legislation needs to be updated to simplify definitions, fill gaps, reduce the stock of regulations and to bring emerging energy technologies within the scope of the legislation.

What are the policy objectives and the intended effects?

The UK Policy objectives are: (1)To fully transpose the Directive by: Building on the UK's exemplary offshore safety and environmental regimes and further enhancing it; maintaining the existing high levels of protection for worker's safety and the environment; and keeping burdens on industry to a minimum.
(2) To simplify and update oil and gas major hazard legislation to take account of operational lessons learned and maintain industry/public confidence in the regulation of emerging energy technologies

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

Alternatives to regulation do not apply as they would not fulfil our obligations under EU Law. Our preferred legislative option is to mesh the majority of requirements into existing legislation and incorporate new provisions where necessary. We will use copy out where possible, but will also use elaboration to ensure consistency with domestic regulations and also use administrative procedures. The bulk of the requirements will be implemented via new Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015 (SCR 2015) which will replace SCR 2005. The remaining environmental requirements will be implemented by amendments to existing regulations. DECC intend to amend the Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) Regulations 1998. Licensing requirements will be implemented by the Offshore Petroleum Licensing (Offshore Safety Directive) Regulations 2015.
There is one option for establishing the CA (plus the notional do-nothing option): Option 2, a partnership CA to regulate the major hazard risks covered by the Directive. This would provide a single regulatory face of the CA to industry and achieve compliance by July 2015 without incurring Machinery of Government change.

I the policy be reviewed? It will be reviewed. **If applicable, set review date: July 2020**

Does implementation go beyond minimum EU requirements?			No		
Are any of these organisations in scope? If Micros not exempted set out reason in Evidence Base.	**Micro** Yes	**< 20** Yes	**Small** Yes	**Medium** Yes	**Large** Yes
What is the CO_2 equivalent change in greenhouse gas emissions? (Million tonnes CO_2 equivalent)			**Traded:** N/a	**Non-traded:** **N/a**	

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 Ministers:

The Rt Hon Matthew Hancock, Minister of State for Energy on 2 February 2015; and
Lord Freud, Minister for Welfare Reform on 19 March 2015.

Summary: Analysis & Evidence

Policy Option 1

Description: Status quo

FULL ECONOMIC ASSESSMENT

Price Base Year 2014	PV Base Year 2015	Time Period Years 10	Net Benefit (Present Value (PV)) (£m) Nil		
			Low: Nil	High: Nil	Best Estimate: Nil

COSTS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Cost** (Present Value)
Low	Nil	4	Nil	**Nil**
High	Nil		Nil	**Nil**
Best Estimate	Nil		Nil	**Nil**

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

This is the notional baseline and no monetised costs have been estimated.

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

No non-monetised costs have been considered.

BENEFITS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Benefit** (Present Value)
Low	Nil	4	Nil	**Nil**
High	Nil		Nil	**Nil**
Best Estimate	Nil		Nil	**Nil**

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

This is the notional baseline and no monetised benefits have been estimated.

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

No non-monetised benefits have been considered.

Key assumptions/sensitivities/risks

Discount rate (%) 3.5

No applicable.

BUSINESS ASSESSMENT (Option 1)

Direct impact on business (Equivalent Annual) £m:			**In scope of OITO?**	**Measure qualifies as**
Costs: Nil	**Benefits:** Nil	**Net:** Nil	N/A	N/A

Summary: Analysis & Evidence — Policy Option 2

Description: Transpose Offshore Directive into UK law with partnership Competent Authority for offshore major hazard risk

FULL ECONOMIC ASSESSMENT

Price Base Year	PV Base Year	Time Period Years	Net Benefit (Present Value (PV)) (£m)		
2014	2015	10	Low: -110.85	High: -281.78	Best Estimate: -196.21

COSTS (£m)	Total Transition (Present Value, Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low	32.5	4 Years	9.3	**110.8**
High	104.6		21.1	**282.1**
Best Estimate	68.5		15.2	**196.4**

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

The costs of transposing the Directive would be mostly borne by business, either directly or through cost recovery by the Offshore Competent Authority. Based on best estimate ten-year present values, the direct cost to industry of complying with changes to HSE legislation to implement the Directive would be around £150m and to comply with changes to DECC legislation, around £30m. Costs incurred by the Competent Authority (CA) would be around £3m for its set-up and management. Costs that the CA would recover from industry would be around £8.5m for assessments related to changes to HSE legislation and around £5m for changes related to DECC legislation. The costs to industry of the update of additional HSE legislation would be a ten-year present value of around £0.4m to industry. The costs to industry arising from the Environmental Liability Directive are estimated to be around £0.25m.

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

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low	Nil	4 Years	Nil	**Nil**
High	Nil		0.04	**0.4**
Best Estimate	Nil		0.02	**0.2**

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

Under the changes in scope of the Environmental Liability Directive, it is anticipated that a small amount of compensation might be paid out for water damage, which would be used to mitigate environmental damage of an equal value; i.e. a ten-year present value of around £0.2m. This is a benefit to society as a whole.

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

The Directive is intended to reduce the likelihood of offshore major accidents. While the current UK regime is well-established and robust, it is expected that the greater oversight provided by the joint Competent Authority for safety and environmental risks would provide greater assurance. Further amendments to safety legislation would permit the control of health and safety risks in emerging onshore gas and hydrocarbon sectors.

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

The key assumption for costs to industry over the appraisal period is the number of installations, as discussed in section 7. The number of new installations coming into scope of the regulations each year and the number dropping out is not certain and is subject to a reduction in viable fields on the UK Continental Shelf (UKCS). DECC and HSE have reviewed these assumptions during consultation and concluded that the assumptions remained reasonable.

BUSINESS ASSESSMENT (Option 2)

Direct impact on business (Equivalent Annual) £m:			In scope of OITO?	Measure qualifies as
Costs: £17.1	**Benefits:** £0.0	**Net:** -£17.1	No	N/A

Evidence Base (for summary sheets)

1. Introduction to the sector

1. The UK oil and gas industry is the UK's largest industrial investor, supporting around 350,000 jobs directly and indirectly in extraction and exploration, plus another 100,000 in exporting goods and services.[1] It makes a substantial contribution to the UK's economy and in 2013-14 it paid £5 billion in direct taxes.[2] To date the UK has produced around 42 billion barrels of oil and gas and the Government's best estimate of remaining recoverable hydrocarbon resources (discovered reserves and potential undiscovered resources) from the UKCS is in the range of 11 – 21 billion barrels of oil equivalent (boe). [3]

2. In addition to the economic importance, maximising recovery of the UK's indigenous supplies of oil and gas will help maintain security of supply as the UK transitions to a low-carbon future, with DECC's projections showing that in 2030 oil and gas will still be providing 70% of the UK's primary energy requirements.[4] In 2013, the UK Continental Shelf (UKCS) produced 61% of the UK's oil product demand and 50% of gross UK gas demand.[5]

2. Problem under consideration

3. Following the Deepwater Horizon incident in the Gulf of Mexico in April 2010, the European Commission (EC) expressed its initial views on the safety of offshore oil and gas operations in its communication "Facing the challenge of the safety of offshore oil and gas activities" (published on 13 October 2010).[6] The EC communication concluded that the existing divergent and fragmented regulatory framework applying to the major hazards relating to offshore oil and gas operations in Europe, along with current industry safety practices, did not provide adequate assurance that risks from offshore accidents were minimised throughout the European Union.

4. In October 2011, the EC published its proposals for a direct-acting European Regulation to strengthen the EU offshore oil and gas regulatory system. During negotiations on the draft instrument, the UK stakeholders (Ministers, industry and offshore workforce representatives) argued strongly for a Directive rather than a direct-acting European Regulation, as the latter would have resulted in the need to revoke many of the UK's existing offshore oil and gas regulations. Industry argued that totally different regulations would result in excessive burdens and a potential reduction in safety. Furthermore, since the EC claimed to be using the UK's regulatory system as a template for the proposals, it was felt that its intention was to maintain and promote this exemplary regime.

5. The UK also negotiated the inclusion in the Directive of additional key safety and environmental requirements from the UK regime that were considered to be

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[1] http://www.oilandgasuk.co.uk/employment.cfm
[2] https://www.gov.uk/government/statistics/statistics-of-government-revenues-from-uk-oil-and-gas-production
[3] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/328095/Summary_of_UK_Recoverable_Hydrocarbon_Resources_2014.pdf
[4] https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2014
[5] Energy Trends Table 1.3 September 2014
[6] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=COM:2010:0560:FIN:EN:PDF

essential to mitigating the risk of major accidents (e.g. the design notifications for production installations, relocation notifications and weekly well reports). By the end of these negotiations, the UK had successfully secured a Directive, the aim of which is to reduce as far as possible the occurrence of major accidents related to offshore oil and gas operations and to limit their consequences.

6. Directive 2013/30/EU (the Directive) was published on 28th June 2013. It contains requirements relating to licensing, safety and environmental protection so the Department of Energy and Climate Change (DECC) and the Health and Safety Executive (HSE) will jointly lead the transposition to fully implement the Directive by 19 July 2015.

7. To ensure that industry can maintain existing procedures as far as possible to keep administrative burdens to a minimum, the majority of the Directive requirements will be transposed into new Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015 (SCR 2015). Many of the requirements are already implemented through the existing Offshore Installations (Safety Case) Regulations 2005 (SCR 2005), but where existing regulations need to be amended or elaborated and where new provisions are necessary, these will be incorporated into SCR 2015, which will replace SCR 2005 for offshore oil and gas operations. Please note that to avoid gold plating the Directive requirements, SCR 2005 will remain in place for oil and gas operations within internal waters. Such operations are not within the scope of the Directive. Maintaining SCR 2005 will maintain current standards for oil and gas operations in internal waters, and will also maintain the requirements that implement Directive 92/91, which covers the minimum requirements for improving the safety and health of workers in the mineral-extracting industries through drilling.

8. The Directive requires that a report on major hazards is produced by operators and owners. HSE and DECC propose to use the safety case as the vehicle to deliver this requirement. As the UK's offshore safety regime already requires operators and owners to produce a safety case, which has a great deal of the information required to be in the report on major hazards, the regulations requiring a safety case will be amended to provide details of the relevant environmental information required to meet the Directive requirements. However, duplicating environmental information already provided for assessment and acceptance under the Oil Pollution Emergency Plan (OPEP), Environmental Management System (EMS) and Environmental Impact Assessment (EIA) processes, would introduce unnecessary administrative burdens on the Industry and regulators. We are therefore proposing, when appropriate, that the safety case contains relevant short descriptions of the required environmental information with links to existing environmental documentation (e.g. OPEPs, and EIAs). Guidance will be provided in relation to the relevant content of the environmental information submitted to DECC and the descriptions that will be required in the safety case.

9. In practice, this will mean that operators and owners will not have to include within the safety case the same environmental information and/or demonstrations and assessments that they have already provided to DECC for assessment and acceptance, and when appropriate, descriptions will be sufficient. However, additional or revised environmental information, not assessed and accepted by DECC, (e.g. information that forms part of a combined safety and environmental submission) will have to be submitted with the safety case for the competent authority to assess, and when appropriate, accept. From a competent authority perspective, this will mean that the safety case cannot be accepted, until the

assessment and acceptance procedures under the OPEP, and EIA processes have also been completed. However, we do not see this being an obstacle, as the existing timescales for all relevant assessment and acceptance procedures will remain unchanged, with the use of the new competent authority IT portal expected to improve the efficiency and effectiveness of the submission and acceptance processes over time.

10. In addition, further legislative amendments are required to implement the environmental and licensing requirements of the Directive. DECC intends to amend the Merchant Shipping (Oil Pollution Preparedness, Response Co-operation Convention) Regulations 1998. Licensing requirements will be implemented by the Offshore Petroleum Licensing (Offshore Safety Directive) Regulations 2015.

11. With respect to the national emergency response plans and emergency preparedness provisions of the Directive, it is considered that existing UK legislation and guidance meets those requirements. On that basis, the Department for Transport (DfT) and the Maritime and Coastguard Agency (MCA) do not need to introduce new legislation for the purposes of implementing the Directive's provisions in Articles 29 and 30. Consequently, no Impact Assessment is needed for these aspects. This view was tested with stakeholders during the consultation who overwhelmingly agreed with this assessment (98%).

12. The Department for Environment, Food and Rural Affairs (Defra) and the Devolved Administrations (DAs) are responsible for transposing Article 38 of the Directive, which extends the offshore scope of the Environmental Liability Directive (ELD) to cover water damage in marine waters that fall within the scope of the Marine Strategy Framework Directive. Defra and the DAs will achieve transposition via appropriate amendments to their respective Environmental Damage (Prevention and Remediation) Regulations.

13. Some of the requirements will also be delivered by updating existing administrative mechanisms (e.g. confidential systems for reporting safety and environmental concerns).

14. The Directive requires Member States to establish a new offshore Competent Authority (CA) by 19 July 2015 to oversee industry compliance with the Directive and to undertake certain related functions such as accepting and/or assessing reports on major hazards and other required documentation. Under the current UK regime, the Health and Safety Executive (HSE) is responsible for implementing health and safety legislation as it relates to offshore oil and gas operations, and this is performed by their Energy Division. The Department of Energy and Climate Change (DECC) is responsible for implementing offshore environmental legislation, and this is performed by their Offshore Oil and Gas Environment and Decommissioning team (OGED).

15. DECC and HSE already work closely together, albeit separately, under a Memorandum of Understanding (MoU) which establishes a framework for liaison between the two regulators and their regimes. Examples include a coordinated sign-off procedure for all new exploration and appraisal wells, and joint environmental and safety inspections if this is considered appropriate. The MoU is supported by a high-level Cross-Departmental group.

16. These existing liaison arrangements are not sufficient to comply with the requirements of the Directive. The preferred option is Option 2: for DECC and

HSE to extend the existing arrangements and to work in partnership to deliver the CA functions specified in the Directive, with each party concentrating on their areas of expertise. The CA would be governed via an enhanced MoU between DECC and HSE, and would be similar to the existing model used for the regulation of onshore major hazard installations.[7]

2.1. Updating the regime and reducing the stock of regulation

17. In parallel with the changes to the UK offshore oil and gas safety regime in relation to the Directive, HSE is also considering some simplifications and updates to existing oil and gas major hazard legislation to take account of operational lessons and to bring some emerging energy technologies (e.g. underground coal gasification) within scope. We are also taking this opportunity to reduce the stock of offshore legislation when appropriate:

    - Under Directive 92/91 on the minimum requirements for improving the safety and health of workers in the mineral-extracting industries through drilling, we are proposing to bring the emerging technology of underground coal gasification within the scope of our onshore oil and gas major hazard legislation;
    - Hydrocarbon gas is now being stored onshore in solution mined salt caverns, with operators voluntarily complying with the UK's onshore major hazard regime. To achieve consistency longer-term, and maintain public and investor confidence that robust regulation is in place, we plan to update our onshore oil and gas major hazard legislation to cover these activities;
    - We propose updating the definition of an offshore installation in the Offshore Installations and Pipelines (Management and Administration) Regulations 1995 to provide clarity and consistency with the definition in the 2013 Health and Safety at Work etc. Act (Application Outside Great Britain) Order and to ensure that when an offshore installation is used for other purposes it reverts back to being an offshore installation for high risk decommissioning/dismantling operations;
    - We plan to mesh the Offshore Installations (Safety Zones) Regulations 1987 into the Offshore Installations and Pipeline Works (Management and Administration) Regulations and then revoke the 1987 regulations;
    - We plan to place the requirement to register deaths on onshore installations into the Offshore Installations and Pipeline Works (Management and Administration) Regulations and then revoke the Logbook and Registration of Deaths Regulations 1972; and
    - We propose to revoke the Offshore Safety (Miscellaneous Amendments) Regulations 2002 (which extends the definition of offshore installation) and incorporate the requirements in the updated definition of offshore installation (mentioned above).

[7] The COMAH Competent Authority for onshore major hazard installations involves HSE and the Environment Agency (in England and Wales) and the Scottish Environment Protection Agency (in Scotland).

3. Rationale for intervention

3.1. Transposition approach

18. The rationale for the transposition approach takes full account of the Government's Guiding Principles for EU Legislation. The key focus is on minimising the burdens on the offshore oil and gas industry and fulfilling the UK's goal (regulator, industry and trade unions) of keeping intact the high standards maintained under the UK's current offshore regulatory regimes. Therefore, although the Government's preferred approach is to use 'copy out' for transposition where possible, we intend to mesh the majority of Directive requirements into the existing safety and environmental regimes. We do not intend to 'gold plate' any of the Directive's minimum requirements that will be new to the UK offshore regimes, but there are a few elements of the current legislation that go beyond the Directive, which we propose to keep in order to maintain the standards of the existing regime. Similarly, where necessary we will elaborate the Directive requirements to ensure that they are clear to industry and to maintain consistency with the current regulations.

19. In summary, we will 'copy out' where possible but also use a variety of approaches to implement the Directive. We will:

- Transpose Directive requirements using existing UK regulations and amending them as necessary to fully meet the duties. For offshore oil and gas operations, the SCR 2005 will be replaced by the SCR 2015 with the existing provisions expanded and new duties included;
- Amend existing regulations to cover some of the environmental requirements. It is intended to amend the Merchant Shipping (Oil Pollution Preparedness, Response and Co-operations Convention) Regulations 1998.
- Introduce new regulations. The licensing requirements will be implemented by the Offshore Petroleum Licensing (Offshore Safety Directive) Regulations 2015;
- Amend the respective UK Environmental Damage (Prevention and Remediation) Regulations to transpose Article 38 of the Directive;
- Maintain standards under the current oil and gas regime (e.g. definitions of major accident enter and leave notifications and the existing coverage of oil spill response plans) and justify any gold-plating of Directive requirements in this IA;
- Elaborate the Directive's wording to clarify what is required (e.g. by adding 'as low as is reasonably practicable' or other UK legal terms) to ensure consistency with the existing UK health and safety regime;
- Not fully implement any requirements that are not enforceable (e.g. The Directive places an absolute duty on operators and owners of offshore installations to prepare standards and guidance. However, it does not indicate which operators or owners must do this, and what guidance they must produce. These omissions make this requirement unenforceable. We will modify this requirement to meet with the current UK practice, that operators and owners are encouraged to take part in producing guidance and standards; and
- Implement some of the Directive's requirements by using administrative means (e.g. the functions of the new offshore CA and mechanisms for reporting safety and environmental concerns).

3.2. Gold Plating

20. By maintaining the current offshore oil and gas regime and existing standards for safety and environmental protection there are a few areas where we potentially gold plate the Directive implementation. In each case, this is to maintain the current scope and standards, for example by keeping existing UK legislative requirements within SCR 2015. In summary, the three areas of gold plating proposed to maintain the scope of the current UK offshore oil and gas regimes and the present health, safety and environmental standards are:

- Maintaining the definition of major accident that industry is used to, and to keep diving operations of fewer than five people in scope;
- Keeping supplementary units (e.g. additional power supplies) that are more than 500m from an installation within the scope of HSE's definition of offshore installation; and
- Keeping non-production installations within scope for enter and leave notification requirements to maintain health and safety standards.

21. DECC initially intended to maintain an approval procedure for operator appointments, as the licence operator and the Directive operator would be the same entity and DECC did not want to weaken the procedure for licence operatorship and replace it with a notification procedure. However, following consideration of the responses to the consultation, it has been agreed that new operatorship roles – the well operator and the installation operator – will be created, and the Licensing Authority will only have the right of objection for those operatorship roles, which have been created solely to implement the Directive requirements. As such there is no longer any gold plating in relation to this element.

3.3. Updating HSE domestic oil and gas legislation and reducing stock

22. Learning from operational experience over the past ten years, HSE has identified that amendments to health and safety legislation are necessary to clarify what structures fall within the definition of offshore installation. There is also a need to ensure that once an offshore installation has been used for other purposes (e.g. helicopter landing pad or wind farm), it reverts back to being an offshore installation for dismantling activities.

23. Experience of regulating the early exploration phase of shale gas operations in the UK has highlighted to the Government the importance of having robust regulation in place to build public and investor confidence. To ensure that future emerging energy technologies (e.g. underground coal gasification) are covered by a robust regulatory regime for their exploration phase, while making sure that the UK fully implements Directive 92/91, steps need to be taken to bring such activities within scope of our onshore oil and gas regulatory regime.

24. To maintain public and investor confidence in hydrocarbon gas storage in salt caverns, and ensure that any future operators follow the robust regulation that has been voluntarily adopted by this sector, we plan to update our onshore oil and gas major hazard legislation to cover these activities. Non-legislative approaches would not deliver the same outcome in terms of ensuring future operators comply, maintaining public and investor confidence that a robust

regulatory regime is in place, and ensuring that operational information is delivered to the regulator on time so that they can intervene effectively.

25. Under the Red Tape Challenge and the commitment to meet Professor Löfstedt's recommendations following his review of health and safety[8]**,** HSE also agreed to take steps to contribute to the Governments goal of reducing the stock of regulation and consider if it can simplify its oil and gas regulation and approved codes of practice.

4. Policy objectives

26. The UK policy objectives are to fully transpose the Directive requirements into Domestic Legislation by July 2015 in a way that:

- Minimises the adverse impact of any changes on the oil and gas industry and UK interests by adopting the least burdensome approach;
- Maintains the current levels of protection for safety and the environment;
- Embeds the new requirements so that they further enhance the UK's world class offshore oil and gas regulatory regime; and
- Is open and transparent and ensures consistency with current regulations.

27. In addition, the UK will also look to deliver policy objectives related to:

- Updating and simplifying existing oil and gas legislation and guidance;
- Maintaining public and investor confidence in emerging energy technologies by bringing them within scope of a robust and appropriate health and safety regime; and
- Contributing to the Government's goal of reducing the stock of regulations.

5. Description of options considered (including do nothing)

5.1. Offshore Competent Authority

28. The consultation IA included several options for establishing the offshore CA, all of which, bar the first, would at least; meet the minimum requirements of the Directive, but which would function differently. The options were:

- Option 1 - Do Nothing
- Option 2: A DECC/HSE partnership Competent Authority to deliver the requirements of the Offshore Directive 2013/30/EU

[8] Reclaiming Health and Safety for all: An independent review of health and safety legislation by Professor Ragnar Lofstedt; November 2011

- Option 3: A DECC/HSE partnership Competent Authority covering all offshore safety and environmental regulation
- Option 4: HSE becomes the offshore safety and environment Competent Authority
- Option 5: An independent “stand alone” offshore safety & environmental Competent Authority

29. The Government’s preferred approach was Option 2. Under Option 2 DECC and HSE would work together under a set of common CA arrangements. From a stakeholder perspective, these arrangements would manifest themselves as a single regulatory face, including:

    - DECC and HSE staff working seamlessly under a set of common CA systems and processes;
    - A CA online portal for all notification and submissions to the CA, regardless of whether they relate to safety or environmental issues;
    - A single, coherent set of CA assessment/acceptance procedures for safety cases, notifications etc.;
    - A single CA intervention plan for each operator and owner, covering all planned CA inspection activities;
    - Proactive CA interventions fully coordinated and planned, with presumption in favour of joint DECC/HSE visits wherever possible;
    - Coordinated CA investigations, with decisions made at an early stage as to which regulatory partner should lead;
    - A single enforcement policy covering all CA enforcement; and
    - A CA website for all information relating to the CA.

30. This approach avoids major machinery of Government changes, and provides a single, consistent regulatory interface for industry with respect to the prevention of the major hazard safety and environmental events covered by the Directive. It also requires minimal changes to the already robust UK offshore regulatory regime, and fully implements the Directive in line with UK Government policy. .

31. All the options considered were detailed in the IA that accompanied the Consultation Document (CD), with the CD itself outlining the rationale for selecting Option 2 as the preferred option. Respondents were asked whether they agreed with that rationale.

32. 79% of respondents disagreed with the proposed approach for establishing a partnership Competent Authority (Option 2). Those that disagreed said that there should be one offshore regulator, with more than half (23 out of 45) specifying their preference for Option 5 (an independent stand-alone competent authority). Eighteen of those who disagreed accepted there may be a need for an interim option, given the time it would take to set up a new stand-alone competent authority. However, the majority specified that even in the short term the competent authority should cover all offshore safety and environmental regulation, and not just major hazards. Twelve respondents, nine of them from Trade Unions, Verification Bodies or Government bodies agreed with the proposal.

33. The Government has considered the responses to the CD in great detail and it has been decided, and agreed by Ministers, to proceed with the preferred option to create a DECC/HSE partnership Competent Authority to regulate major

hazard offshore safety and environmental risks covered by the Directive. In addition to the reasons set out above, it is also considered that:

- Whilst this proposal was not supported by the majority of industry consultees, many recognised that to move towards the industry's preferred approach, an independent "stand alone" authority, would be difficult to achieve in the timescales for implementing the Directive. There are also advantages to Government and Industry in that this approach is the least costly option and will, we believe, provide a seamless approach and meet the requirements of the Directive without going beyond them.

- Some Industry respondents believe a single regulator/agency would enable a move to a single, risk based approach to health, safety and environmental regulation. There are fundamental differences in how HSE and DECC are often required to regulate. HSE mostly operates a "goal setting" regime and DECC implement prescriptive regimes as dictated by Convention for the Protection of the Marine Environment of the North East Atlantic (the OSPAR convention) and EU law. These different approaches are sometimes incompatible and forming a single organisation with a single regulatory approach will not change this position.

34. As such, Option 3, 4 and 5 from the consultation stage IA are no longer considered viable based on either their deliverability within the necessary timescales, the disruption they would cause given the significant other changes occurring in the oil and gas industry and/or in light of Ministers' decisions. Therefore, they have been ruled out of further consideration as part of this final stage IA.

5.1.1 DECC/HSE partnership Competent Authority to deliver the requirements of the Offshore Directive 2013/30/EU – how it will work

35. This will involve relevant functions of DECC and HSE being brought together under a partnership CA whose role it is to regulate major hazard offshore safety and environmental risks covered by the Directive. Each party will concentrate on their areas of expertise, working under shared policies, procedures and information portals and reporting to a senior CA Management Group. It will provide a single regulatory face for the offshore industry covering all major safety and environmental issues that are contained in the Directive on the safety of offshore oil and gas operations.

36. Work has already started to deliver this option as it provides the minimum change necessary to comply with Directive 2013/30/EU. It is the easiest option to achieve compliance with the Directive by July 2015 as current established systems would be broadly maintained and it is similar to the approach used to regulate the onshore major hazards industries via the COMAH Competent Authority. In addition, it avoids any disruption from Machinery of Government changes, which is particularly important at this time, given the recommendations of the Wood Review which have been accepted by the Government and the consequent establishment of the Oil & Gas Authority (OGA).

37. The scope of the CA would be limited to major hazard safety/environmental regulation under the requirement arising from Directive 2013/30/EU. Thus, the CA will include the substantial majority of HSE's offshore work, and HSE considers that its residual personal health, safety and welfare responsibilities offshore can easily follow the CA policies, processes and procedures to provide an integrated approach to safety, health and welfare offshore. However, the CA will only cover a small proportion of DECC's offshore environmental inspection/regulation remit, so the existing, separate, DECC regulatory regime for non-safety related environmental risk (such as major oil spill prevention where there is no link to safety i.e. pipelines, chemical permitting, oil discharge permitting and environmental impact/habitat assessment) will remain a parallel regime outside the CA, whilst continuing to work closely with it.

5.2. Legislation

38. The preferred legislative option is to transpose the bulk of the Directive requirements into the new Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015 (SCR 2015), which will replace the SCR 2005 for offshore oil and gas operations. This will include amending existing regulations, and incorporating new requirements to fully implement the Directive.

39. It is intended that the environmental requirements will be implemented by amending the Merchant Shipping (Oil Pollution Preparedness, Response Co-operation Convention) Regulations 1998. The licensing requirements will be implemented by Offshore Petroleum Licensing (Offshore Safety Directive) Regulations 2015.

40. A range of approaches will also be used to further integrate the new requirements into the UK regime and this will include using administrative mechanisms and procedures when appropriate, for example, to establish the offshore CA and tripartite consultation mechanisms.

41. In terms of the additional updates to the UK's onshore major hazard oil and gas legislative regime to bring emerging energy technologies within scope, non-legislative options were considered. However, these would not deliver the goal of maintaining public and investor confidence that a robust regulatory regime was in place, or ensure that future operators complied with the necessary standards.

42. The Option of copying-out the Directive and creating a new piece of legislation, was considered, and although simpler from a legal perspective, would place unnecessary burdens on industry. A key goal of the transposition is to minimise the impact on industry by maintaining as much as possible of the existing regime. Since the introduction of the Safety Case regime in 2005, the UK has developed an exemplary oil and gas regulatory system. During negotiations the EU also used the UK regime as a template and as an example of good practice. Changing this regime would put the UK at a significant disadvantage and create unnecessary administrative burdens.

6. Summary of research undertaken to inform the IA

43. Representatives of the offshore oil and gas industry have been heavily involved in the research to inform estimation of the direct costs to industry in this analysis, which was completed in two phases. The first phase was to estimate the baseline costs to industry of the existing major hazard regimes, both offshore and onshore, and which led to the creation of the Baseline Assessment in 2012. This was in anticipation of the need for robust baseline estimates for this impact assessment and was a major undertaking, as such an exercise to cost compliance had never been undertaken before.

44. The second phase has sought to estimate the costs to industry of the changes to the major hazard regimes brought about to implement the Directive in UK law, thereby adjusting the current costs faced by industry as estimated by the Baseline Assessment. This ran from late 2013 up until completion of the consultation-stage impact assessment in April 2014. This process continued into the consultation period as the cost estimates were refined through consultation responses and, in some cases, followed up with research group members and the wider industry to fill gaps or address emerging issues.

45. The same method was used for both pieces of research to ensure consistency. Both used a heavily adapted version of the Delphi method[9] across two research groups, with an interim period for the participants to gather data. The idea behind this was to take a small sample, but to try to ensure that the measurements taken were consistent and accurate. A quantitative census survey of all companies in the sector was considered, but HSE social researchers deemed this too onerous on business to fill in and likely to have a low response rate. Non-response bias would be almost inevitable, as those who responded would necessarily be those with spare resource to fill in a lengthy survey. A survey of this type would also be prone to measurement error, as there would be no way to check that respondents had included or excluded the same costs from their measurements.

46. In creating the Baseline Assessment, an initial research group was held in September 2011 with an industry group of representatives from several companies to go through a pre-prepared question set. The members of the group were selected to ensure that it captured a wide range of offshore companies that varied by size and type of installation. The initial meeting aimed to reduce measurement error by ensuring that members responded based on a common understanding of what should be included and excluded and clarifying what constituted ‘good’ and ‘bad’ evidence for costs. Based on the initial discussion with the group, the question set was refined to clarify some issues and cover additional areas raised by the group. This was then sent to participants to complete. The results were collated before the second research group.

47. A second research group was held in December 2011 with the same participants to provide an opportunity for the representatives to challenge each other’s results, correct any errors and misunderstandings, and reach a consensus that allowed ranged costs to be estimated. This was followed by a stage of validation or ‘reality checking’ held in January 2012 with a group of five companies who had

[9] Named after the Oracle of Delphi, the Delphi method involves consulting a panel of experts to gain understanding of a subject or area, particularly in forecasting changes, such as industry costs for changes to legislation.

not been on the original group to challenge any unjustified assumptions and assess if the estimates were realistic. This took the form of a three-hour meeting and led to a few minor amendments, but no major changes.

48. Lastly, all of the participants were sent a copy of the final report for comment. This was to ensure that the information presented included the necessary caveats and reflected what was agreed at the second research group and the validation meeting. Attendees were informed that a nil response would be treated as indication that they had no issues with the analysis. Although some comments were given regarding the background discussions, no comments were received on the costs.

49. As mentioned above, the method for the second phase of research to estimate the change in costs brought about through the Directive has been similar. An initial research group was held at the start of March 2014 to discuss impacts and evidence and the second at the start of April to agree ranged cost estimates, which have been used as part of the analysis in this IA. Although no formal verification research group was held, as was done with the Baseline Assessment, the process of consultation has given the industry the chance to review and comment on the cost estimates, allowing for a wider verification of the estimates. Consultation responses are discussed alongside relevant estimates and assumptions in Sections 8 and 9 as appropriate.

6.1. Public Consultation

50. The public consultation was published on the HSE website, with links from the DECC website. It ran for 8 weeks, from 28 July to 24 September 2014, with a three day extension to compensate for website downtime. The consultation document was downloaded 3,315 times and the Word questionnaire downloaded 429 times. There were 59 completed copies of the Word questionnaires and 6 completed online questionnaires received, giving a total of 65 responses for analysis.

51. The majority of responses (69%) were from industry stakeholders, ranging from major companies to smaller businesses, providing opinions from across the sector. There was a large representation from key industry organisations, including Oil and Gas UK (representing licensees, operators of production installations, and well operators) and the International Association of Drilling Contractors (representing the majority of drilling contractors). Both of these organisations canvassed the opinions of their members and presented their collective response in the consultation document. In addition there was a good response from the main Trade Unions and key UK verification bodies and also some useful comments received from Non-Departmental Government bodies.

7. Risks and Assumptions

52. All costs and benefits are appraised over a period of 10 years from the year of implementation, 2015, to 2024. This is in keeping with impact assessment guidance that a ten-year period should be used where the lifetime of the policy is not identifiable.

53. Many of the costs in this analysis have been estimated based on forecasts of the number of installations on the UK Continental Shelf (UKCS) over the ten-year appraisal period. At the time of writing in December 2014 there are estimated to be around 386 installations operating in 2015, the first year of this analysis and the year when the regulations would be implemented.

54. Based on observation of the last three years' submissions of new safety cases, each year on average around 15 more installations begin operating on the UKCS, either as installations fixed in position or as mobile installations that can move to different locations. However, the analysis in the consultation stage impact assessment acknowledged that this may include some degree of double-counting as some of these 15 installations might be mobile installations moving from one part of the UKCS to another, and therefore already be in scope of the regulations. It has not been possible to estimate exactly how many installations this may include, but the number is understood to be small. As such, this final stage IA retains this assumption as a simplifying assumption.

55. Each year on average around 1.5 installations begin decommissioning. This is also based on observation of the last three years' submission of dismantling installations safety cases. However, estimates from DECC's Decommissioning Unit are that this number is expected to increase sharply as fields come to the end of their usable lives. They have estimated that the number may increase to around 20 installations per annum in the next few years, which would lead to a net decrease in installations over time. However, this figure is subject to uncertainty as some installations may be mothballed for a period rather than decommissioned in case changes in the oil price make their operation economically viable. This analysis acknowledges that there is uncertainty in the number of installations to be decommissioned over the next ten years, but accepts that the recent figure of 1.5 per annum is too low.

56. For the consultation stage IA, this analysis took a pragmatic approach and assumed that each year 15 installations would begin decommissioning work. The decommissioning of installations can take several years to complete, depending on the size and complexity of the installation. This analysis will assume that each decommissioning operation would take between 1 and 5 years to complete and that of the 15 that begin decommissioning, 3 will be complete after 1 year, a further 3 after 2 years and so on. As such, this assumption delivers a 'steady state' of installation numbers after 5 years, as shown in Table 1. This assumption was subject to review by DECC during the consultation period, which concluded that it remained a reasonable assumption given the uncertainty around both the number of decommissioning projects that will commence in each year of the appraisal period and the length of time each could take to complete.

Table 1: Forecast number of installations 2015 - 2024

Year	No. of installations
Year 0 (2015)	386
Year 1 (2016)	398
Year 2 (2017)	407
Year 3 (2018)	413
Year 4 (2019)	416
Year 5 (2020)	416
Year 6 (2021)	416
Year 7 (2022)	416
Year 8 (2023)	416
Year 9 (2024)	416

57. The impact assessment includes costs and benefits that extend into the future. Consequently, it is important that any monetised impacts are expressed in present values, to enable comparison over time. The discount rate used to generate these present values is defined in the HM Treasury Green Book[10] as 3.5% for any appraisal period of less than 30 years.

58. Costs are in terms of opportunity and financial costs. Where market values are not available, costs are expressed in terms of the best proxy value where relevant. For instance, for any compliance activities that take up the time of a worker or operator/owner, there is a cost of that time. The best proxy for the value of this time is what they could have produced during that time if they were not required to perform these compliance tasks. It is assumed that the worker's productivity is best reflected by the true cost of employing that person (they create as much value as they are paid). In reality this could be conservative for some occupations and staff, but is the best estimate available and is recommended by Government in the Green Book. The true economic cost of employing the person is assumed to be their gross hourly wage rate inflated by 30% to reflect the non-wage costs of employment (such as employer tax and NI contributions, employer contributions to pension and overheads).

59. Ranges are calculated around all estimates to reflect uncertainty in the estimates. The range is either that specified by industry at the research groups or the CA working group, in relation to costs to Government. In some cases, where a point estimate was provided, a range of +/-10% is added around the estimate to provide some degree of uncertainty. Given the thoroughness of the estimates from the research group and the CA working group, this is considered to be appropriate.

60. In preparing the costs in this Impact Assessment, we met with industry in a series of research groups to discuss likely impacts and for them to calculate the costs of each of the new requirements. However, we have to recognise that there are a number of uncertainties at this stage (e.g. the exact information that they will need to provide under a specific requirement), which means that these can only be approximate costs at this time.

61. We have prepared this Impact Assessment following a detailed gap analysis with supporting legal advice. In time, alternative legal interpretations may evolve. This could highlight infraction risks for the UK or identify additional potential areas of

[10] Available at: http://www.hm-treasury.gov.uk/d/green_book_complete.pdf

'gold plating'. It is also possible that political developments (e.g. the possibility of powers being devolved to Scotland) could have a future impact on these proposals and that some of the emerging energy technologies considered in the Impact Assessment start sooner or later than we have anticipated, and are undertaken to a smaller or greater degree than currently forecast. We recognise such risks, and proposals would have to be modified if any changes have a significant impact on the way forward outlined within this document.

8. Key Changes

8.1. Setting up the Offshore Competent Authority

62. DECC and HSE will work in a partnership CA to deliver the functions specified in the Directive, with each party concentrating on their areas of expertise – see Section 5.1 29 paragraph 29 and 30. The CA will be governed via an enhanced MoU between DECC and HSE, and will be similar to the existing model used for the regulation of onshore major hazard installations[11]. A high-level oversight CA Board will provide the forum to agree on implementation arrangements and achieve shared perspectives and decisions.

63. DECC's existing regulation of offshore chemical/oil discharge permits and their environmental assessment regime will not change and will not be covered by the CA.

64. The Directive requires that the UK ensure "the independence and objectivity of the competent authority in carrying out its regulatory functions". It further specifies that "conflicts of Interest shall be prevented between, on one hand, the regulatory functions of the competent authority and, on the other hand the regulatory functions relating to economic development of the offshore natural resources and licensing of offshore oil and gas operations". Although DECC is currently responsible for licensing and the economic development of oil and gas resources via the DECC Licensing, Exploration and Development (LED) Team, this will change shortly following the recommendation in the final report of Sir Ian Wood's "UKCS Maximising Recovery Review[12]". A new arm's length regulatory body will be created, the Oil & Gas Authority (OGA) charged with effective stewardship and economic regulation of UKCS hydrocarbon recovery. Implementation of this recommendation will reinforce the separation of the CA function and the regulatory functions relating to economic development of the offshore natural resources and licensing of offshore oil and gas operations.

[11] The COMAH Competent Authority for onshore major hazard installations involves HSE and the Environment Agency (in England and Wales) and the Scottish Environment Protection Agency (in Scotland).

[12] http://www.woodreview.co.uk/ The Wood Review examined key factors that affect UKCS performance and developed recommendations designed to enhance economic recovery of oil and gas reserves in the future. The interim report was published on 11 November 2013. The final report and recommendations were produced in early 2014 and funding announced in the March 2014 budget to implement the recommendations.

8.2. Operating the Offshore Competent Authority

65. Working as a partnership CA, DECC and HSE will have new responsibilities under the Directive. They will be required to report to the Commission on national measures they have in place regarding access to knowledge, assets and expert resources. They will also be required to produce a report on transposition arrangements.

66. The CA will also need to have a system to receive, assess and accept safety cases, notifications and other documents that are submitted by operators/owners, in addition to providing publicly available information on the structure, accountability, policies, processes and procedures of the CA. DECC and HSE agree that the most effective way to achieve these requirements is to develop an IT portal and create a single point of contact for industry. Once set up this will be maintained as part of CA procedures.

67. There will be new administrative procedures to manage CA operations. These include the CA Management Board, maintaining common operational systems and processes and planning co-ordinated regulatory activity.

68. The CA will also need to assess/approve the information that is submitted by operators/owners to comply with the new regulatory requirements (which are explained in more detail in the changes to legislation sections below). These relate to:

- Descriptions of the Internal Emergency Response Plan;
- The Independent Verification Scheme;
- Corporate Major Accident Policy (CMAPP);
- Safety and Environmental Management System (SEMS);
- Safety Cases;
- Design and Relocation Notification;
- Well Notifications;
- Combined Operations Notifications;
- Dismantling;
- Reporting Imminent Danger or increased risks of a major accident; and
- Reporting major accidents outside the EU.

69. Other new regulatory requirements are for the CA to advise the Licensing Authority on the technical and financial aspects of new licensees on request. The CA will also be required to send an additional delegate to the European Offshore Authorities workgroup meetings.

8.3. Changes to HSE Legislation to implement the Directive

70. This section describes all of the changes to HSE legislation to implement the Directive; the costs follow in Section 9.

8.3.1 Offshore Gas storage and recovery

71. The current definition of “offshore installation” in the Offshore Installations and Pipeline Works (Management and Administration) Regulations 1995 (MAR), and across the suite of HSE’s offshore oil and gas regulations covers the “storage of gas in or under the shore or bed of relevant waters or the recovery of gas stored”. The Directive definition of offshore oil and gas operations excludes gas storage, therefore to avoid gold plating, HSE will remove gas storage from the definition in MAR.

72. This change will not have an impact on current offshore gas storage activities. There is only one offshore installation involved in storing gas, but this installation also produces hydrocarbon gas and therefore has a safety case for the installation and will be regulated by the new CA.

73. No additional offshore gas storage and recovery operations are planned in the near future, but to ensure this activity is sufficiently regulated, work to consider a new offshore gas storage regime will begin once the Directive is transposed. There will be a separate Impact Assessment covering the costs and benefits of this new regime.

74. In response to the public consultation, 89% agreed that gas storage should be removed from the UK definition of offshore installation and that this activity should be covered by a specific regulatory framework. The respondents who disagreed with the proposal felt that the definition (and so new SCR 2015 regime) should apply to all oil and gas operations, including storage, but this would be gold plating as gas storage is not within the scope of the Directive. Some respondents noted the need to consider the future storage of carbon dioxide.

8.3.2 Internal Waters

75. HSE’s offshore oil and gas regulations, including SCR 2005 and the Offshore Installations (Prevention of Fire and Explosion, and Emergency Response) Regulations 1995 (PFEER) apply offshore but also apply within Great Britain as a whole. This is required to implement Directive 92/91/EEC which applies to all of Great Britain, including internal waters. The requirements of the offshore safety Directive, however, do not apply within Great Britain and are restricted to the territorial sea, the exclusive economic zone and the continental shelf of the United Kingdom (offshore).

76. To prevent gold plating when implementing the Directive, HSE cannot apply the new SCR 2015 regime to internal waters, so instead it will maintain the SCR 2005 regime to ensure the current health and safety standards are maintained for oil and gas operations in internal waters. As this approach would involve operations in internal waters being subject to the existing requirements in the current SCR 2005, this would impose no additional burdens on these oil and gas operations.

77. During the public consultation, 90% of respondents agreed with the proposal to apply similar requirements to those in SCR 2005 to oil and gas operations in internal waters. Those who disagreed felt that this twin-track regime was unnecessary and that SCR 2015 should include internal waters, despite the fact that this would be gold plating. One respondent asked about the environmental regulation of internal waters.

8.3.3 Internal Emergency Response Plans

78. Presently, owners or operators prepare and submit emergency response plans under safety legislation, the Offshore Installations (Prevention of Fire and Explosion, and Emergency Response) Regulations 1995 (PFEER) and operators submit oil pollution emergency plans (OPEPs) under environmental legislation, the Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) Regulations 1998 (OPRC). Section 8.5.1 covers the amendments needed to address the revised OPEP requirements.

79. HSE will make amendments to require that the PFEER plan is updated to contain the additional information required under the Directive, including an inventory of emergency response equipment. Although this is currently not a legal provision, owners/operators already keep this type of safety information, and HSE's legislation will require that an inventory of safety emergency response equipment is prepared. Inventories of environmental emergency response equipment are covered in the OPEP.

80. Operators/owners would also need to provide a brief description of the Internal Emergency Response arrangements (referring to both safety and environment submissions) in the safety case and well notifications.

81. 72% of those who responded to the public consultation agreed with the proposal to maintain the current UK approach of having different emergency arrangements under the range of offshore oil and gas legislation. Among those who agreed and those who disagreed, many considered this to be an interim step towards developing proposals that would result in a single plan. DECC and HSE will therefore consider this in the longer term.

8.3.4 Independent verification

82. Presently, under SCR 2005, owners or operators are required to have in place an independent verification scheme to provide assurance that safety-critical elements (SCE) of the installation's plant and equipment are suitable for their intended purpose.

83. Under SCR 2015, this verification scheme would need to be described in the safety case and extended to cover the verification of safety and environmental-critical elements (SECE). This has the potential to impose both a one-off cost to industry for the establishment of this expanded scheme and an ongoing cost from the increased resources necessary to manage a scheme with a wider remit.

84. The extent of any changes to the verification scheme relative to the present one would in part depend on whether installations have any plant or equipment that is environmental-critical, but not safety critical, that would have to be included in the verification system. Early discussions with DECC and industry suggested that there were no such elements, but experience of onshore oil and gas operations suggested that the performance standards for SECE may be different depending on whether they are being considered from a safety or environmental perspective. If this proves to be the case, it will be assessed at the time of review of the SECE submissions, and this may result in some additional costs to industry.

85. The verification scheme would need to comply with some new criteria outlined in the Directive (e.g. arrangements to manage the flow of information between the

operator/owner and the independent verifier and to ensure the verifier is given sufficient authority to carry out their functions). The efforts necessary to make existing schemes compliant will depend in part on the extent to which they already fulfil the criteria through standard operating procedures.

86. In response to the public consultation, 96% supported the proposals to extend the verification scheme requirements in SCR 2015 to include SECE. To help industry comply with this new requirement, DECC and HSE have also agreed to develop guidance on the definition of and management of Environmental Critical Elements that fall within SCR 2015.

8.3.5 Corporate Major Accident Prevention Policy (CMAPP)

87. There is a new requirement for operators/owners to prepare a Corporate Major Accident Prevention Policy (CMAPP) that covers their installations. HSE and DECC believe that although operators/owners will already have some policies in place that may provide some of the information needed, they will not have one that specifically covers the prevention of major accidents. This will have to be produced under SCR 2015 and a copy of this policy will need to be submitted with the Safety Case.

88. 98% of public consultation respondents agreed with the rationale for implementing the requirement for a CMAPP. It was generally observed that industry needed clarification on how to comply with this requirement and this will be addressed in guidance.

8.3.6 Safety and Environmental Management System (SEMS)

89. There is already a legal requirement in the UK to have a safety management system (SMS) under the SCR 2005 and DECC have in place a voluntary agreement implementing a requirement of the Convention for the Protection of the Marine Environment of the North East Atlantic (the OSPAR Convention) that operators should maintain an environmental management system (EMS).

90. To minimise the changes to the UK's offshore oil and gas regime and burdens on Industry, HSE and DECC originally proposed to maintain, but update, the current safety legislative requirements and to make the voluntary EMS requirements a legal requirement under new DECC legislation. However, during formal consultation this proposal was not supported, with the majority of those who disagreed indicating that they preferred one plan, with just over two thirds agreeing that the requirement should be drafted into SCR 2015. Some qualified this by saying they did not support the proposals for the environmental EMS regulations.

91. DECC and HSE have now amended their proposals, and will no longer go forward with the environmental EMS regulations. It is now intended to incorporate the Directive's requirement for a SEMS within the SCR 2015. This approach will allow the few operators or owners who have a separate EMS and SMS, rather than an existing SEMS that is integrated with their overall management system, to maintain this approach. However, they will be required to outline how these separate systems work together as a SEMS and are integrated with their overall management system. An adequate description of the SEMS will then need to be included within the safety case.

8.3.7 Safety Cases

92. The UK already operates a safety case regime under the current SCR 2005. The Directive requires that a report on major hazards is produced. The UK proposes to use the safety case, updated by the SCR 2015, to include relevant descriptions relating to environmental information, with appropriate links to existing environmental demonstrations and assessments, to meet the Directive requirements for a report on major hazards. Operators/owners would need to submit short descriptions of the Verification Scheme, Safety and Environmental Management System, and Internal Emergency Response arrangements in the safety case, but these requirements are assessed in the respective sections of this impact assessment.

93. Owners/operators would also need to include additional general information in the safety case, such as details of the relevant codes, standards and guidance used in the construction and commissioning of the installation. They also need to provide 'any other relevant details' that the CA considers necessary before a safety case is accepted, but in practice this is probably already covered by the existing regime.

94. There was substantial support from the public consultation for the approach to including additional information in the safety case, with 61% of respondents agreeing with the proposal. However, all of those who disagreed and many of those who agreed were strongly opposed to relying on links to the relevant information, stressing that the safety case must continue to be a standalone document. Consequently, the new legislation will require relevant descriptions to be provided in the safety case (not just links) and guidance will be provided on the nature and extent of the information required.

8.3.8 Design and Relocation Notifications

95. Under the current SCR 2005 Regulations, owners or operators of installations are required to submit a design notification in the case of a planned production installation. In addition, where an existing production installation is to be moved, the operator must submit a relocation notification. There are separate requirements to provide environmental information.

96. The key change under the Directive and the SCR 2015, is that Design and Relocation Notifications must now include reference to the environmental information, in addition to the existing safety information. For example, they will need to describe the design concept in relation to major hazard scenarios for both the environment and safety. Although HSE and DECC estimate that the information needed for these notifications may already be produced (e.g. in an Environmental Statement (ES) that describes the option selection process, the proposed re-allocation of a production installation and the environmental considerations relating to the selection and relocation), additional work would be needed to briefly describe and make appropriate links to this information within a design or relocation notification when appropriate.

97. 83% of respondents to the public consultation agreed with this proposal. It was generally accepted that the design and relocation notifications should include short but meaningful descriptions.

8.3.9 Well Notifications

98. Under the current UK regime, well operators are required to submit a well notification. This notification provides the regulator with a range of information, related to the planned well operations. This includes particulars of the well, a description of the well operations and the programme of work. The Directive requires that additional information is included in a well notification and the requirements will be included in the SCR 2015. The requirements include environmental information needing to be submitted along with safety information in the well notifications. Again HSE and DECC estimate that the information needed for these notifications may already be produced as a result of other requirements (e.g. an ES or a request for a Direction when an ES is not required). Additional work will be needed to briefly describe and make appropriate links the information within a well notification.

99. The well notification must now include the findings and comments of the independent competent person (ICP) with a description of the actions taken by the well operator in response to these findings. The well operator must also consult the ICP before submitting a material change to a well notification.

100. 81% of respondents to the public consultation agreed with this proposal for descriptions of environmental information to be included in the well notification. There was general agreement that providing adequate descriptions of the information is the most effective way to implement this.

8.3.10 Combined Operations Notifications

101. Combined Operations Notifications are already submitted under the current regime, but there are new requirements under the Directive. Under the SCR 2015, the operator would need to include environmental information within the notification. Again, HSE and DECC estimate that the information needed for these notifications may already be produced as a result of other requirements (e.g. a request for a navigational consent to locate a non-production installation). Additional work would be needed to briefly describe and make appropriate links to this information within a combined operations notification

102. 91% of respondents to the public consultation agreed with this proposal and guidance will be provided to explain the environmental information and level of detail that is required for the description.

8.3.11 Dismantling a fixed production installation

103. Under the Directive, new information is required when a fixed production installation is being dismantled and the requirements will be included in the SCR 2015. The requirements include: information on the means of isolating hazardous substances and the permanent sealing of wells; a description of the risks to workers and the environment, the total exposed population; and information on the emergency response arrangements to secure safe evacuation and rescue of personnel and to maintain control systems for preventing a major accident to the environment. Again, HSE and DECC estimate that the information needed for these notifications may already be produced as a result of other requirements (e.g. the Decommissioning Programme and supporting documents). Additional work would be needed to briefly describe and make appropriate links to this information in the decommissioning safety case.

104. 90% of respondents to the public consultation agreed with this proposal, although a significant number agreed on condition that the description should provide sufficient information to ensure the decommissioning safety case continues to be a standalone document.

8.3.12 Reporting imminent danger or increased risks of a major accident

105. Under the Directive, when an activity carried out by an operator or owner poses an immediate danger to human health or significantly increases the risk of a major accident, they must take suitable measures, including suspending the activity, until the danger or risk is adequately controlled. When an operator takes such action, they must notify the offshore CA no later than 24 hours after taking the action. Although we would expect industry to already take such measures, the requirement to report taking these measures to the CA is new and will be included in the SCR 2015.

106. Responses to the public consultation illustrated that there was some confusion over this requirement and further clarity is needed. However, half of the respondents agreed that this would require a simple phone call and were content that this did not create a new burden.

8.3.13 Reporting major accidents outside the EU

107. This is a new requirement on licensees and operators who are UK-registered companies, or their subsidiaries, who undertake offshore oil and gas operations outside the EU. Under the SCR 2015, these companies will now need to report to the offshore CA, on request, details of any major accidents they, or their subsidiaries, have been involved in outside the EU.

108. In the public consultation, 85% of respondents disagreed with the assumption that there would be no costs as they did not fully understand what would need to be reported and by whom under his new requirement. Therefore, further evidence was gathered from industry to refine the assessment as explained in section 9.6.13.

8.3.14 Safety Zones

109. The UK Offshore Installations Safety Zones Regulations 1987 specify when a vessel can enter an offshore safety zone. Under the Directive, the owner or operator of the installation would also be able to grant permission for a vessel to enter the safety zone for reasons other than those specified in the regulations.

110. Industry does not envisage any circumstances where such permissions would be granted by an operator or owner and as such this it is assumed that this change will have no impact on industry. 82% of respondents to the public consultation agreed with this assumption and there were no alternative examples provided by those who disagreed.

8.3.15 Collecting and recording data

111. The Directive requires operators/owners to use suitable methods of recording and collecting data that ensures reliability and prevents the possibility of the data

being manipulated. This is a new requirement, but industry report that they already have such measures in place.

112. In the public consultation, there was substantial agreement to this assumption, with 66% agreeing there were suitable systems in place. Those who disagreed generally perceived there was a need for information or systems beyond those already required by existing legislation. This is not the case and guidance will be provided to make it clear to industry that no new information is required.

8.3.16 Enter and Leave notifications

113. MAR currently requires a notification on the day an offshore installation leaves or enters the UK, but in reality industry sends these notifications to HSE prior to the installation leaving or entering the UK. The Directive requires the notification to be submitted prior to the day of entry or departure and HSE intend to copy out this definition and amend MAR. As industry already submit these notifications prior to the day of entry or departure, HSE estimate that this will have no practical impact on industry and as such would pose no additional cost.

8.3.17 Promoting change to staff

114. The research group reported that it would take effort to communicate and promote the changes required by the Directive across their organisations and to build the new requirements into their procedures and practices. The activities identified as necessary to familiarise all staff with the changes would include visiting installations, preparing and distributing promotional material, holding meetings and workshops, updating websites and training.

115. The respondents to the public consultation agreed that it would take time and effort to promote changes to staff. Information on the estimated costs is provided in section 9.6.17.

8.3.18 Implementing Act on data reporting criteria and format

116. The Directive indicates that an Implementing Act will be introduced to outline a new offshore data reporting system. The Implementing Act was not available at the time of producing the consultation IA, as it was only published on the 20th October 2014. During the public consultation, 56% of respondents disagreed with the initial assessment that reporting under the new implementing act would not impose additional costs. The majority of those who disagreed considered that a new requirement would involve change and therefore incur a cost, but some indicated they could not comment until they had more information on the new requirements.

117. In the original consultation document, DECC and HSE also considered that additional databases and computer systems would be required by industry for the management of the new Implementing Act Report.

118. After reviewing the Implementing Act, it is clear to DECC and HSE that industry already provide some of the information required, via the RIDDOR, voluntary hydrocarbon releases reporting system, and the PON 1 notification system (for environmental releases). However, there are some sections of the

Implementing Act that are new, and some which require additional, or more detailed information, than previously reported to the regulator. We therefore anticipate that providing this additional information will place new burdens on industry, and potentially require new databases in which to collect and process the required data.

119. The Implementing Act will also outline a common reporting format for the CA to use when preparing Annual Reports to the European Commission and for the CA making information publically available. This will place an additional burden on the CA.

8.3.19 Preparing and revising standards and good practice

120. In conjunction with regulators and industry bodies such as Step Change and the Offshore Industry Advisory Committee (OIAC), operators and owners currently share information and produce and revise standards and guidance. The Directive imposes a requirement on operators and owners, in consultation with the CA, to prepare and revise standards and guidance on best practice in relation to the control of major hazards. The Directive, however, does not indicate which operators or owners would be involved or specify what guidance they must produce.

121. To implement this requirement, DECC and HSE propose to create an obligation encouraging operators and owners to co-operate by participating in producing standards and guidance. To meet this new duty they will be expected to continue to take part in producing guidance via Step Change, OIAC and other industry forums. By maintaining the current practical arrangements, there would be no impact on industry from this new requirement.

122. This proposal was supported by 84% of respondents to the public consultation, many of who agreed that it aligned with current arrangements and industry practice.

8.3.20 Transport of Inspectors offshore

123. HSE already has a requirement in the Offshore Installations (Inspectors and Casualties) Regulations 1973 (ICR) for duty holders to transport inspectors offshore, and provide accommodation and meals etc. The Directive requirement to transport inspectors is slightly broader than that in the ICR (e.g. it covers transport to a vessel associated with offshore oil and gas operations).

124. As industry already provides transport, accommodation etc. to DECC and HSE inspectors, we assumed that this duty will impose no additional costs on industry.

125. In the public consultation this was overwhelmingly supported with 87% of respondents agreeing with this assumption.

8.3.21 Tripartite consultation

126. The Offshore Industry Advisory Committee (OIAC) currently acts as the offshore tripartite body for assessing safety issues related to the offshore oil and gas industry. Under the Directive there is a requirement to establish

arrangements to enable operators and owners to contribute to effective tripartite consultation. DECC and HSE consider the most effective way to deliver the Directive requirement is to use OIAC as the mechanism for tripartite consultation.

127. This proposal would build on the existing arrangements, but some change would be required to extend the terms of reference, to incorporate environmental consultation in addition to safety. We assume that the current members of OIAC could cover both safety and environmental issues and any administrative work could continue to be provided by the existing OIAC secretariat. We therefore anticipate no additional costs to the CA from updating the OIAC to deliver this function.

128. The public consultation demonstrated overwhelming support for this proposal with 93% agreeing that OIAC should be used to deliver the Directive requirement for a mechanism for tripartite consultation.

8.4. Maintaining Existing Standards and Gold Plating of HSE Legislation

8.4.1 Definition of major accident

129. The current UK definition of major accident includes “the failure of life support systems for diving operations in connection with the installation, the detachment of a diving bell used for such operations or the trapping of a diver in a diving bell or other subsea chamber used for such operations”. This is not included in the Directive definition. The definition of major accident does make provision for ‘any other incident leading to fatalities or serious injury to five or more persons…’ and given that most diving operations associated with offshore installations involve five or more people, this is likely to be covered in most instances. It could also be argued that any subsea work on installations or pipelines is likely to be covered by other aspects of the Directive’s definition of a major accident. However, a small number of such diving operations will involve fewer than five people and we would prefer to make it legally clear that such diving operations remain within scope of the new SCR. Retaining the current diving-specific element in the definition of the major hazard definition would provide clarity and consistency.

130. HSE is concerned that the omission of such operations from the definition of major accident, and so consideration within the safety case, which is the document that lays out the measures in place to effectively control major accident risks, would have a detrimental effect on offshore diving safety. Commercial diving is widely recognised as a hazardous work activity – particularly offshore. Over the last 40 years, at least 52 divers have died while working in the offshore oil and gas industry in the North Sea.

131. As all operators/owners are currently required to address diving matters in the safety cases, there would be no additional burden on industry from maintaining all diving operations within the definition of major accident. Recent discussions with the Diving Industry Committee (DIC), and informal discussions with the offshore diving industry, indicate that retention of the diving-specific major hazard definitions would be widely supported. HSE is therefore proposing to keep this reference to diving operations within the UK definition of major accident.

132. The Directive's definition of major accident also only covers an event involving major damage to the structure of the installation, where there is a significant potential to cause fatalities or serious personal injury. The definition of major accident in SCR 2005 does not have the qualification relating to fatalities or serious injury, and so this could be seen as gold plating. As keeping the SCR wording will maintain current practices and standards we will keep the current wording in the UK definition.

133. There was overwhelming support for this proposal in the public consultation with 92% of respondents agreeing with the approach to dealing with the definition of major accident.

8.4.2 Supplementary Units connected to an offshore installation

134. The definition of 'offshore installation' in the Offshore Installations and Pipeline Works (Management and Administration) Regulations 1995 (MAR) and SCR 2005 and across HSE's suite of offshore oil and gas regulations, includes reference to supplementary units which are connected to it or any part of it. The term was included within the definition of 'offshore installation' to ensure such structures associated with the installation (e.g. back-up energy supplies), the failure of which could contribute to a major accident, were seen as part of an offshore installation, and so captured by HSE's offshore safety regulations.

135. The Directive only covers such units within the safety zone (i.e. within 500m of the installation). Although to date no supplementary units have been associated with an offshore installation in the UK, they could be in future and HSE considers that there could be detrimental impacts on safety standards if these units did not remain in scope of the offshore regulations. HSE therefore proposes to keep supplementary units (within and beyond 500m) within the definition of 'offshore installation'.

136. An offshore installation with a supplementary unit would need to have a safety case that is fully compliant with the new requirements and it is expected that the supplementary unit would be assessed as part of that safety case. As this is an existing requirement, and industry would need to comply if they were currently using supplementary units, there is no impact or new burden placed on industry from this proposal.

137. There was overwhelming support for this proposal in the public consultation, with 94% agreeing that supplementary units beyond 500m should continue to be covered by the definition of offshore installation.

8.4.3 Enter or Leave notifications for non-production installations

138. The Offshore Installations and Pipeline Works (Management and Administration) Regulations 1995 (MAR), currently covers this requirement. In the UK, HSE monitors the movements of both production and non-production installations (NPIs, e.g. drilling rigs), but the Directive only requires production installations to submit these notifications. As such the current regime includes an element of gold plating. However, HSE believes it is crucial to continue to monitor the movement of NPIs under the major hazard regime to maintain safety standards and minimise the possibility of major accidents on NPIs, such as the Deepwater Horizon disaster in the Gulf of Mexico. Industry is already following this regime so there is no additional burden in maintaining this requirement.

139. There was overwhelming support for this proposal in the public consultation with 98% agreeing that the UK should continue to monitor the movement of NPI's.

8.5. Changes to DECC Environmental Legislation to implement the Directive

140. This section of the Impact Assessment (IA) outlines the changes required to DECC's offshore environmental legislative regime to implement the Directive.

141. The environmental legislative regime relating to offshore oil and gas operations is very comprehensive. Following a review of the Articles of the Directive, it is apparent that the majority of the environmental requirements are already met by existing legislation. Only minimal changes are therefore necessary to meet the environmental requirements of the Directive. Apart from amendments to the emergency response legislation, no other changes to the existing offshore environmental legislation are anticipated.

142. DECC proposes to introduce one set of Regulations, which will amend the Merchant Shipping (Oil Pollution Preparedness, Response Co-operation Convention) Regulations 1998 (the "OPRC Regulations") and implement other Directive requirements. The proposed regulations would include provisions relating to specific elements of the Directive that are described below.

8.5.1 Amendments to the OPRC Regulations

143. The OPRC Regulations implement, in part, the International Convention on Oil Pollution Preparedness, Response and Co-operation 1990, and came into being as a consequence of the Merchant Shipping (Oil Pollution Preparedness, Response and Cooperation) Order 1997. The regulations require harbour authorities and operators of oil handling facilities and offshore installations, where there is a risk of an oil pollution incident, to have Oil Pollution Emergency Plans that are compatible with the National Contingency Plan and appropriate to deal with oil pollution in the area for which the harbour authority or operator is responsible. The Secretary of State (SoS) for DECC exercises the powers in relation to offshore installations and pipelines, and it is the duty of operators to implement the approved plan in the event of an oil pollution incident. There are also powers of inspection for the SoS in relation to offshore installations and pipelines. The OPRC Regulations also contain provisions requiring masters of United Kingdom ships, and individuals having charge of harbours, oil handling facilities and offshore installations to report certain events involving the discharge of oil. The OPRC Regulations do not currently extend to owners of non-production installations. The operator currently submits the OPEP, which includes details of the non-production installation.

144. The proposed regulations for transposing the Directive will amend the OPRC Regulations to align them with the requirements of the Directive. The existing OPRC regulations already require the following**:**

- Every operator of an offshore installation to have an OPEP in place;

- Every operator to submit a plan to the SoS for approval;
- In preparing the OPEP every operator to take into account any guidance;
- Every operator to fully review its OPEP every 5 years after submission;
- Every operator to implement its OPEP in the event of an oil pollution incident;
- Individuals in charge of offshore installations to report oil in the sea to HM Coastguard; and
- Persons duly authorised by the SoS to have the power to inspect any offshore installation.

145. To align the OPRC Regulation with the obligations of the Directive, a number of amendments are proposed. The OPRC requirements will be extended to:

(a) include the decommissioning of offshore installations. There will be a new requirement for offshore operators to prepare an OPEP for decommissioning operations, which will be the responsibility of the operator of the relevant production facilities that are being decommissioned.

(b) Include owners of non-production offshore installations, who will be required to submit an OPEP for their installations. The required content of a non-production OPEP will be aligned with the requirements of the Directive.

(c) Require operators to submit an addendum to the owner's plan to cover specific well operations or a series of operations. Similarly, there is an additional requirement for the operator's OPEP to be amended to take into account any additional risks related to an oil pollution incident identified for combined operations, prior to those operations commencing.

(d) Amend the requirement under the OPRC to 'submit a plan' to a requirement for every offshore installation to have an approved OPEP (as part of the Directive's obligations to produce an Internal Emergency Response Plan, or IERP) prior to the commencement of the offshore oil and gas operations covered by the plan, This will also include requirements for operators and owners to:

   - undertake a full review and re-submission of an OPEP every 5 years, measured from the date of approval of the original plan.
   - to undertake a full review and re-submission of an OPEP following any relevant material change, or when directed to undertake such a review by DECC.

(e) require operators and owners to undertake OPEP exercises to maintain relevant preparedness for the implementation of the plan and interaction with the external emergency response plan. Operators and owners will also be required to retain evidence of OPEP exercises undertaken both onshore and offshore and to provide that evidence on request.

(f) provide powers to prohibit operations where no OPEP is in place, where the plan is deemed insufficient or where the requirements of the plan are not being met; and for Inspectors to be able to serve notices when deemed appropriate.

(g) require operators/owners to include in the OPEP an analysis of the oil spill response effectiveness and a complete inventory of oil spill emergency response equipment pertinent to their offshore oil and gas operations.

146. 71% of respondents to the public consultation supported these proposals. Those who disagreed largely did so on the basis that further clarity and guidance was required. DECC and HSE will provide further guidance to address the issues raised

8.5.2 Financial liability arrangements

147. Operators undertaking exploration and appraisal well drilling operations using a Mobile Drilling Unit (MoDU) are currently required to provide evidence of financial liability arrangements, to ensure that sufficient funds or indemnity provisions are available to cover both first party costs (well control) and third party costs (caused by pollution damage), associated with an oil pollution incident. This requirement is currently linked to the legal requirement to prepare and implement an OPEP as detailed in the OPRC Regulations. If the required financial arrangements are not in place, DECC would take the view that the operator had not demonstrated that the provisions of the OPEP could be fully implemented, so approval of the OPEP would be withheld.

148. The Directive requires that appropriate financial provisions are taken into account when assessing applicants for licences or for different stages of operatorship. The new regulations will therefore include powers to require details of financial liability arrangements to be submitted to support relevant OPEPs.

8.5.3 Existing Legislation – Charging Schemes

149. In accordance with Article 8(7) of the Directive, the UK intends to establish or amend charging schemes whereby the financial costs to the CA in carrying out its duties under the Directive will be recovered from licensees, operators or owners.

150. DECC is currently undertaking a major review of the charging schemes associated with the environmental legislative regime. This is a complex exercise and it is not intended to develop new schemes prior to implementation of the Directive. However, provisions will be brought forward in separate regulations which will provide for a scheme to recover relevant departmental costs. This will be addressed in a separate IA.

8.6. Changes to DECC Licensing Legislation to implement the Directive

8.6.1. Licensing

151. The Directive requirements include elements relating to the competency and capacity of the licensee(s). Following a review of the Articles of the Directive, it is apparent that the majority of the licensing obligations are already met by existing legislation and guidance. However, it is considered necessary to reinforce some of the obligations in new legislation.

8.6.2. Operatorship

152. The Directive requirements also include elements relating to the appointment of operators to conduct the offshore oil and gas operations. It was originally proposed that a single operator would be appointed to fulfil the requirements of the DECC licence operator and to implement the requirements of the Directive. However, 76% of the responses to the consultation disagreed with this proposal, for a range of reasons.

153. Over half of those who disagreed said they would prefer to maintain the multiple operator approach that has existed since and worked effectively for more than 20 years, as there was no evidence of safety or environmental performance being compromised. Another well supported reason for disagreeing was that the current model provided economies of scale and efficiencies, and it was considered that a single operator model would remove the flexibility that accommodates both large and small companies. Many felt that, in particular, the single operator model would deter small companies from entering the UKCS, because it would be impractical and uneconomical. Several respondents also commented that it would create additional burdens in relation to late-life field opportunities and materially reduce the options for hydrocarbon recovery. Some also concluded that it would create barriers to investment that would undermine the efforts to maximise economic recovery and be counter-productive to the aims of the Wood Review.

154. It will be necessary to erect a legislative procedure to implement a multiple operator model and accommodate the appointment and assessment processes detailed in the Directive. To ensure effective transposition, DECC therefore propose to introduce new regulations, the Offshore Petroleum Licensing (Offshore Safety Directive) Regulations 2015, to implement the licensing and operatorship requirements of the Directive and accommodate industry's requirements.

155. Where possible, DECC will use 'copy out' in the proposed regulations, but in some instances it will be necessary to elaborate the Directive's wording to clarify what is required (e.g. by amending definitions to ensure consistency with the existing licensing and operatorship regime). In this context, DECC will be elaborating the Directive definition of an operator by introducing two new categories of operator, and this will affect the Impact Assessment:

- "installation operator" means the person appointed [in accordance with regulation 4(2)] to conduct any offshore petroleum operations, except those functions carried out by a well operator; and

- "well operator" in relation to a well or proposed well means the person appointed [in accordance with regulation 4(2)] to conduct the planning and execution of well operations.

156. Under the current HSE regime, the installation operator role can be fulfilled by a "duty holder", and the well operator role can occasionally be fulfilled by a turn-key drilling contractor or well management company.

157. Some of the requirements detailed in the proposed regulations will also be supplemented by administrative means (e.g. the nature of the environmental and

safety submissions required to support applications for licenses and operator appointments will be detailed in guidance).

8.7. Maintaining Existing Standards in DECC Legislation

8.7.1 Oil Pollution Emergency Plans

158. The International Convention on Oil Pollution Preparedness, Response and Cooperation[13] (OPRC Convention) was adopted by the International Maritime Organization (IMO) in 1990 and came into force in the United Kingdom (UK) on 16 December 1997 and was implemented through The Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) Regulations 1998 (OPRC Regulations).

159. The OPRC Convention encourages States to: respond to a major oil pollution incident; maintain an adequate capability to deal with oil pollution emergencies; and have plans in place which are coordinated with its External Emergency Response Plan.

160. To satisfy the requirements of the OPRC Convention, DECC requires that an Oil Pollution Emergency Plan (OPEP) is submitted by the operator of all offshore installations and associated pipelines in the UKCS where there is a risk of oil pollution. The Convention requirements are also currently satisfied in submissions prepared by operators involved in well or combined operations. The OPEP is a response document which is implemented by operators when responding to any oil pollution event irrespective of whether the instigating event/incident constitutes a major accident.

161. DECC propose to maintain the existing OPEP requirements for operators in addition to imposing the additional Directive requirements for an IERP that relate to the environmental aspects.

162. DECC considers that restricting the OPEP to the content specified in the Directive would exclude important information in relation to modelling the scope of an oil release, where it may impact shorelines or cross international median lines, or identifying the environmental sensitivities which could be impacted by a release.

163. The additional detail required under OPRC is not considered to be gold-plating[14], as this is an international requirement for all qualifying oil pollution emergency plans. The additional detail provides valuable information for evaluating the potential extent of a major oil pollution incident, the suitability of the response plans and the environmental sensitivities that could be impacted. As this information is already provided, there will be no practical impact on industry.

[13] http://www.imo.org/About/Conventions/ListOfConventions/Pages/International-Convention-on-Oil-Pollution-Preparedness,-Response-and-Co-operation-(OPRC).aspx
[14] In accordance with the Better Regulation Framework Manual 1.9.8.iii

8.7.2 Licensing Provisions (Gold Plating no longer proposed)

164. In the consultation stage IA, DECC and HSE proposed to maintain the existing approval process for operators, whereas the Directive only required a non-objection procedure. The existing Model Clause that deals with licence operatorship provides that the licensee may not allow an operator to act as such without the prior approval of the Secretary of State. The Directive, however, only requires that the Licensing Authority should have a power to object to the appointment of an operator appointed for the purpose of implementing the Directive requirements. Initially, DECC and HSE intended to maintain an approval procedure for operator appointments as it was proposed that a single operator model would be utilised to implement the Directive requirements. The licence operator and the Directive operator would therefore be the same entity, and maintaining the approval process in line with the existing Model Clause provisions was considered to be a more robust approach. However, following consideration of the industry responses to the consultation, it has been agreed that new operatorship roles – the well operator and the installation operator – will be created to implement the Directive requirement, and these roles will not require the prior approval of the Secretary of State. As such there will be no gold plating. The Licensing Authority will only have a right of objection after the event for the operatorship roles that have been created solely to implement the Directive requirements. This will have no impact on the existing licence operatorship arrangements, which will be separate from the Directive requirements.

8.8. Changes to Legislation to implement Article 38 of the Directive

165. The Directive also extends, through Article 38, the offshore scope of the Environmental Liability Directive (ELD) for oil and gas operations and other anthropogenic activities. The ELD already applies to damage affecting protected habitats and species out to 200 nautical miles and damage to all waters covered by the Water Framework Directive which extend to between 1 and 3 nautical miles of the landward baseline of the territorial sea within different countries of the UK. The Directive extends the scope of water damage to cover all marine waters within the scope of the Marine Strategy Framework Directive (MSFD).

166. The ELD only requires action where a business or other operator has caused – or is imminently about to cause - significant environmental damage. Evidence to date suggests this happens very rarely. In the five years since the law came into force between 2009 and 2014, there have been only three cases of water damage on land or in coastal waters in the UK. Across the EU from 2007 to 2014 there have been 389 cases of water damage[15]. By comparison there are likely to be fewer applicable cases on average in the area between 1 and 200 nautical miles (as evidenced in the original ELD Impact Assessment (IA)) because of reduced levels of economic activity and owing to increased difficulty to monitor,

[15] This figure masks a wide variation reported by Member States, three of which accounted for 80% of the incidents. The very great majority reported fewer than a dozen, with 14 reporting zero or one case.

detect and enforce offshore damage. This assessment is strengthened by the fact that no cases of damage to species and habitats in the marine environment have yet fallen under the ELD in any country in the EU. This suggests that damage to water beyond 1 or 3 nautical miles might happen once every ten or more years across the UK.

167. If and where such damage does arise, there are likely to be costs under existing arrangements to address the damage, depending on the nature of damage caused. Analysis undertaken for the original EU ELD IA suggested that opportunities to directly restore damage will be limited in the marine environment and that the measures required will therefore largely be to compensate for the damage. There may be limited opportunities to take such measures in the marine environment so these may sometimes be taken on land. The compensatory measures for one case of water damage on land are estimated to have cost less than £200 thousand (from the damage assessment for the case). The costs of cases across the EU range from £2,440 to £2.07 million (for all types of cases, not just water damage) although this is likely to include some costs that would have been incurred irrespective of the ELD.

168. The main costs are therefore likely to relate to paying for environmental improvements.

169. Work from the original ELD IA suggests the following activities have the potential to cause damage in the marine environment: fisheries, shipping, activities releasing contaminants on land, contaminants from the oil and gas industries, mariculture, litter, disturbance, engineering operations and dredging and dumping. But that damage would have to be very significant to trigger action under the ELD.

8.9. Changes to HSE regulations for updating the safety regime and reducing the stock of regulation

8.9.1 Updating the health and safety regulatory regime

The definition of offshore installation

170. In April 2013, HSE introduced the Health and Safety at Work etc. Act 1974 (Application Outside Great Britain) Order 2013. In this Order, the definition of offshore installation was updated to give legal clarity that it was vessels whose primary purpose is accommodation, or those undertaking activities that involved mechanically entering the pressure containment boundary of a well, that fell within the scope of this definition.

171. At this time, HSE also recognised that if an offshore installation was ever used for other purposes, these would likely be related to oil and gas activities (e.g. used as helicopter bases). When such installations came to the end of their life, HSE would want to ensure that it could still regulate future high risk decommissioning and demolition activities associated with such installations using its offshore major hazard regulations. HSE therefore removed the exclusion of any structure “which has ceased to be used for any of the purpose specified”, from the Order. This was to ensure that all activities in relation to a non-mobile structure which was formally an offshore installation, continued to be covered by the Order.

172. For consistency, and to ensure health and safety standards are maintained when high risk decommissioning and dismantling activities on offshore installations occur, HSE is now proposing to make the same changes to the definition of the offshore installation in the Offshore Installations and Pipeline Works (Management and Administrative) Regulations 1995 (MAR).

Some of the respondents to the public consultation expressed the view that offshore installations could be used for purposes not associated with oil and gas operations (e.g. related to wind farms), so HSE cannot simply continue to apply the safety case regime to all structures at all times. HSE therefore propose to update the definition of offshore installation in its offshore major hazard legislation to ensure that these regulations do not apply when an offshore installation is used for other purposes, but continue to apply (e.g. for decommissioning and dismantling) when those other activities stop. This would maintain the existing requirements for a safety case for decommissioning, but ensure that no major hazard requirements would be placed on an offshore installation if it were used for any purposes**.**

Underground Coal Gasification (UCG)

173. HSE's onshore major hazard regime delivers part of Directive 92/91, which covers the minimum requirements for improving the safety and health of workers in the mineral-extracting industries through drilling. It is relevant to note that the Framework Health and Safety Directive (89/391/EEC), under which the drilling Directive is made, requires advances in technology to be taken into account and used to deliver improved levels of protection with regards to workers' health and safety over time. Therefore, it is expected that the minimum standards will evolve over time (in line with technological advances). At the time the UK implemented Directive 92/91, it did not foresee UCG taking place. However, a recent survey of Member States as part of a European Commission Review of Directive 92/91 indicated that some Member States already see this activity as being "mineral extraction through drilling" and so is covered by Directive 92/91.

174. Bringing UCG within the UK's onshore oil and gas major hazard framework will enable the UK to continue to meet the requirements of European Directive 92/91, making sure new technologies are brought within scope. Therefore, the costs associated with updating the UK regime are not governed by the one-in two-out (OITO) rule.

175. Recent experience of the political and public interest in shale gas has resulted in a great deal of scrutiny of HSE's onshore oil and gas major hazard legal framework. The requirements contained within our onshore major hazard legislation have been seen as broadly sufficient to regulate health and safety. However, we are not in such a strong position for UCG. This activity is out of scope of our onshore major hazard legislation. As the first UCG pilot is expected to start onshore in 3-5 years (the Coal Authority does not anticipate an offshore project, if at all, within the next ten years), HSE (with support from DECC and the Coal Authority) is proposing to bring UCG within the scope of HSE's onshore oil and gas major hazard regime.

176. 94% of respondents to the public consultation supported this proposal to bring UCG within the scope of HSE's onshore oil and gas major hazard regulations.

Onshore Combustible Gas Storage and Recovery

177. Natural gas storage and recovery activities have been taking place in the UK for many years in depleted oil and gas reservoirs both onshore and offshore. These are usually filled with natural gas through a borehole, which is designed and constructed to standards similar to those used for onshore and offshore gas extraction wells. The storage of hydrocarbon gas is likely to grow in the coming years as the need increases to store such gas when it is available in the summer, for recovery when it is required in the winter. There are three possible scenarios for offshore hydrocarbon gas storage and recovery:

- In depleted and partially depleted hydrocarbon fields - such activities have been taking place onshore and offshore for many years;
- Processes that will use naturally occurring geological formations that do not include petroleum (e.g. chalk) - this approach is still under development; and
- Storage in solution mined salt caverns (currently takes place onshore).

178. In the future as well as storing and recovering hydrocarbon gas, it may also be necessary to store and recover the products of UCG. We will therefore collectively call this "combustible gas storage and recovery". As combustible gas storage and recovery activities have major hazard potential, it is important to ensure HSE has the jurisdiction to regulate all three storage and recovery scenarios, using relevant onshore and offshore major hazard regulations. Currently, and for the foreseeable future, offshore storage and recovery will take place in depleted oil and gas reservoirs only, and these activities are already covered by our offshore oil and gas regime.

179. Onshore, combustible gas storage and recovery currently takes place in both depleted reservoirs and solution mined salt caverns. HSE currently regulates onshore hydrocarbon gas storage and recovery in depleted reservoirs using its onshore oil and gas major hazard regime (e.g. the Borehole Sites and Operations Regulations 1995 (BSOR) and the offshore wells regulations - which apply onshore and offshore). These regulations ensure HSE receives notifications covering the design, construction and operation of wells used for hydrocarbon gas storage and recovery. Well notifications allow HSE to intervene early and provide advice before storage operations begin. The legislation also requires operators to have an independent well examination scheme in place, an important additional barrier to ensuring well integrity.

180. Legal advice suggests that underground storage of combustible gas in solution mined salt caverns and geological formations that do not contain oil and gas are not covered by BSOR or the well design and construction regulations. This is because of limitations in the current definitions contained in both regulations and which pre-date unconventional methods of gas storage and extraction.

181. To date there are nearly 75 active salt cavern combustible gas storage sites which HSE are responsible for, with over 85 associated wells. All the companies drilling these wells have voluntarily worked to the requirements of our onshore oil and gas major hazard regime, although sometimes the required information is provided slightly later than required under the regulations. The construction of two more underground salt cavern storage sites, with up to 24 new wells, has recently started by the same operators who have voluntarily provided information to HSE. We expect they will do this again in the future, so there will be no additional costs associated with these changes.

182. HSE anticipates that sometime in the future it is possible that new operators may enter this field who do not want to voluntarily meet the requirements of the legislation. If such a situation did arise, HSE would want to maintain standards and to ensure a level playing field between existing and new contractors. Therefore, HSE is proposing to formally bring these activities within the scope of its onshore oil and gas major hazard legislation. This will also help to maintain public and investor confidence, by ensuring a robust regulatory regime is in place for this emerging sector.

183. 97% of respondents to the public consultation supported this proposal to bring gas storage activities within HSE onshore oil and gas major hazard legislation.

Reporting well dangerous occurrences

184. The Reporting of Injuries, Diseases and Dangerous Occurrences Regulations 1995 (RIDDOR) require that well dangerous occurrences (e.g. a blowout) are reported to HSE. This allows HSE to investigate such incidents when appropriate, to identify the lessons learnt from such incidents and to ensure that action is taken by the operator when necessary. Amendments to these regulations are required to ensure that all well dangerous occurrences associated with the emerging energy technologies outlined above (e.g. UCG and onshore combustible gas storage and recovery) are reported. There is also a need to clarify who has the duty to report such occurrences. HSE proposes an amendment to the definition of "well" and "responsible person" in RIDDOR.

8.9.2 Further reducing the stock of offshore regulations

185. The Government is looking to reduce its overall stock of regulations that apply to businesses, including those associated with the safety of offshore oil and gas operations. HSE proposes meshing some existing Regulations, which were made a long time ago and now only have a few remaining requirements, into some of the core offshore health and safety legislation. In total HSE expects to reduce the stock of offshore regulations by three by taking these steps.

186. The remaining requirements of the Offshore Installations (Safety Zones) Regulations 1987 will be meshed into the Offshore Installations and Pipeline Works (Management and Administration) Regulations and the 1987 regulations will be revoked.

187. The Logbook and Registration of Deaths Regulations 1972 will be revoked, with the remaining requirement to register deaths on offshore installations to be included in the Offshore Installations and Pipeline Works (Management and Administration) Regulations.

188. The Offshore Safety (Miscellaneous Amendments) Regulations 2002, which extend the definition of offshore installation, will be revoked and these requirements incorporated into the updated definition of offshore installation included in the new and amended regulations.

189. The remaining requirements of the Offshore Installations (Inspectors and Casualties) Regulations 1973 (ICR), and the Submarine Pipelines (Inspectors etc.) Regulations 1977 (SPIRS), will be meshed into the Offshore Installations Pipeline Works (Management and Administration) Regulations 1995 (MAR). This

MAR regulation will also cover the Directive requirement to transport inspectors offshore. The ICR and SPIRS will be revoked.

190. The public consultation responses showed overwhelming support for these proposals to reduce the overall stock of offshore regulations, ranging between 98% and 100% agreement to each proposal.

9. Costs and Benefits Appraisal

9.1 Costs for Setting up the Offshore Competent Authority

191. In the consultation stage IA, it was assumed that the one-off costs for setting up the CA and the annual management costs would be recovered from industry. Following further consideration of the proposed approach, in consultation with operational and finance teams, HSE and DECC have now confirmed that the CA set up costs would not be recovered, but borne by Government.

192. This is because DECC and HSE inspectors only recover costs for a proportion of their worked hours each year: typically between a half and three-quarters, depending on the grade and specialism. It is expected that the work inspectors will undertake as part of the CA set up and management costs will account for a proportion of their non cost-recoverable hours as this has been the approach to date, and/or that some inspectors will increase their cost recoverable hours to cover the deficit in others'. The costs to Government will therefore be absorbed within planned administrative budgets, with the resource required to set-up the CA effectively falling within the expected annual variation in the nature of activity (non-recoverable) undertaken by both departments, which is in line with project based working practices. As such, there will not be a reduction in the regulatory activities provided to market participants as a result of establishing the CA and therefore industry will not incur a reduction in services (i.e. zero opportunity cost) relative to those they receive under existing arrangements.

9.1.1 Option 1 set up costs

193. Under the notional Option 1, the status quo remains and no CA would be set up. By definition there are no costs or benefits associated with this option. The other option will be assessed against this baseline.

9.1.2 Option 2 set up costs

194. Under Option 2, HSE and DECC would work together in a partnership CA to regulate offshore health and safety and environmental major accident risks. HSE and DECC would continue to manage their own areas of specialism, but with a new over-arching management structure. The time necessary to set this up has been estimated by the joint working group including representatives from HSE and DECC currently engaged in managing the establishment of the CA. This included time to train staff, to set up new processes and procedures and to

establish a user group. This has been converted to a cost of time by HSE economists using the full economic cost model.

195. The estimated work time given by the joint working group covered over 11 thousand hours and nearly 20 different grades of staff, including administrators, technical specialists and senior civil servants. The cost has been estimated using each worker's Full Economic Cost (FEC) and is summarised in Table 2. Adding a range of +/- 10%, this gives an **estimated one-off cost to Government** of this time of between about £1.0 million and £1.3 million, with a **best estimate of around £1.2 million**. This cost would occur in Year 0 of the appraisal period.

Table 2: Summary of calculation of Option 2 CA set up costs[16]

Government worker	Hours spent	FEC per hour	Total cost of time
DECC Senior Civil Servant	26	£120	£3,100
DECC Higher Executive Officer	650	£79	£51,000
DECC Grade 7	440	£101	£44,000
DECC Grade 6	440	£107	£47,000
DECC Environmental Specialist	440	£122	£53,000
DECC Senior Environmental Specialist	1,300	£128	£160,000
DECC Environmental Team Leader	150	£129	£20,000
DECC Offshore Investigator	45	£90	£4,000
DECC Senior Offshore Investigator	350	£94	£33,000
DECC Investigations Team Leader	140	£107	£15,000
DECC IT worker	780	£63	£49,000
HSE Band 1 Offshore Inspector (Higher)	530	£129	£68,000
HSE Band 2 Offshore Inspector (Higher)	2,100	£120	£254,000
HSE Band 3 Offshore Inspector (Higher)	2,700	£108	£297,000
HSE Band 4 Administrator	75	£51	£3,800
HSE Band 5 Administrator	170	£45	£7,400
HSE Band 6 Administrator	450	£38	£17,000
HSE Band 3 IT Worker	380	£63	£24,000
HSE Senior Civil Servant Band 2	15	£129	£1,900
TOTAL	**11,000**		**£1,200,000**

Note: totals may not sum due to rounding

9.1.3 Reporting to the European Commission on knowledge management

196. The CA would be required by the Directive to report to the European Commission (EC) on the arrangements put in place to manage access to knowledge, assets and expert resources. The CA working group have estimated that the full economic cost (FEC) of time necessary to complete this would be as follows:

[16] Please note: the consultation stage IA underestimated the FEC per hour of DECC staff. This was because the DECC estimates did not include overheads and were estimated based on annual costs using the wrong number of working hours per annum. This has been corrected in this final stage IA.

- around 4 hours of DECC Grade 6 time at an FEC of £107.16 per hour
- around 22.5 hours of DECC Senior Environmental Specialist time at an FEC of £127.71 per hour
- around 7.5 hours of DECC Environmental Team Leader time at an FEC of £129.27 per hour
- around 4 hours of HSE Band 1 Offshore Inspector time at an FEC of £129.45 per hour
- around 11 hours of HSE Band 2 Offshore Inspector time at an FEC of £120.32 per hour
- around 22.5 hours of HSE Band 3 Offshore Inspector time at an FEC of £108.34 per hour

197. Adding a range of uncertainty of +/- 10%, this gives an **estimated one-off cost to Government** of between around £7.7 thousand and £9.4 thousand, with a **best estimate of around £8.5 thousand.** This cost would be borne in Year 0 of the appraisal period under Option 2. .

9.1.4 Reporting to the European Commission on transposition

198. The CA would also be required by the Directive to report to the EC on the arrangements it has put in place to transpose the Directive in UK law. The CA working group have estimated that the full economic cost (FEC) of time necessary to complete this would be as follows:

- around 15 hours of DECC Higher Executive Officer time at an FEC of £78.54 per hour
- around 15 hours of HSE Band 2 Regulatory Inspector time at an FEC of £74.30 per hour

199. Adding a range of uncertainty of +/- 10%, this gives an **estimated one-off cost to Government** of between around £2.1 thousand and £2.5 thousand, with a **best estimate of around £2.3 thousand**. This cost would be borne in Year 0 of the appraisal period under Option 2.

9.1.5 Setting up online portal

200. DECC and HSE propose to extend the online portal that DECC already have in place for the submission of documents by industry. DECC and HSE agree that this development of this existing system is the most effective way to carry out the functions required of it under the Directive. DECC have estimated this **one-off cost to Government** at between around £150 thousand and £200 thousand, with a **best estimate of around £175 thousand.** This would be borne in Year 0 of the appraisal period under Option 2.

9.1.6 Implementing Act on data reporting criteria and format

201. HSE had estimated to the European Commission the cost of adapting existing databases and systems for the new reporting criteria at between around £67.5 thousand and £165 thousand, with a **best estimate of around £113 thousand cost to Government**. This estimate includes both HSE time and charges from IT contractors. HSE attempted to refine this estimate with its IT providers during

consultation, and found that it remains a reasonable estimate. This would be borne in Year 0 of the appraisal period under all Option 2.

9.1.7 Summary of Set Up Costs to Competent Authority

202. Table 3 summarises the costs to set up the CA under Option 2. These costs would be borne by Government.

Table 3: Summarised costs to industry to set up Competent Authority (£thousands)

	Low	Best Estimate	High
Establishing new policies and procedures	£1,037	£1,152	£1,268
Knowledge management report to EC	£8	£9	£9
Transposition report to EC	£2	£2	£3
Extending online portal	£150	£175	£200
Setting up reporting system	£68	£113	£165
TOTAL	**£1,264**	**£1,451**	**£1,644**

Note: figures are ten-year present values. Totals may not sum due to rounding.

9.2 Costs for operating the Offshore Competent Authority

203. As explained in paragraphs 191 to 192, management costs for operating the CA would not be recovered from industry unless they relate to specific interventions. The costs that follow are all borne by Government, unless stated otherwise.

9.2.1 Option 1 management costs

204. Under the notional Option 1, the status quo remains and no CA would be set up. By definition there are no costs or benefits associated with this option. The other option will be assessed against this baseline.

9.2.2 Option 2 management costs

205. The processes required to manage the operations of the CA under Option 2 and the time required to do so have been estimated by the joint working group and these efforts have been costed by HSE economists using the full economic cost model. These costs would be borne by Government. The management functions would include the CA management board, the maintenance of CA processes and procedures and operational liaison between HSE and DECC. These costs would be additional to current operating costs of DECC and HSE, which would continue.

206. The time required to manage the CA estimated by the joint working group covered nearly 1 thousand hours and nearly 15 different grades of staff. The cost has been estimated using each worker's Full Economic Cost (FEC) and is summarised in Table 4. Adding a range of +/- 10%, this gives an estimated

annual cost to Government of between around £98 thousand and £119 thousand, with a best estimate of around £108 thousand.

207. This ongoing cost would be borne from Year 1 to Year 9 of the appraisal period. This gives an **estimated present value over ten years** of between around £742 thousand and £907 thousand, with a **best estimate of around £824 thousand**.

Table 4: Summary of calculation of Option 2 CA annual management costs

Government worker	Hours spent	FEC per hour	Total cost of time
DECC Senior Civil Servant	38	£120	£4,500
DECC Senior Executive Officer	19	£86	£1,600
DECC Grade 7	38	£101	£3,800
DECC Grade 6	75	£107	£8,000
DECC Environmental Specialist	120	£122	£14,700
DECC Senior Environmental Specialist	158	£128	£20,100
DECC Environmental Team Leader	38	£129	£4,800
HSE Band 1 Offshore Inspector (Higher)	38	£129	£4,900
HSE Band 2 Offshore Inspector (Higher)	158	£120	£19,000
HSE Band 3 Offshore Inspector (Higher)	158	£108	£17,100
HSE Band 2 Administrator	38	£73	£2,700
HSE Band 3 Administrator	38	£60	£2,200
HSE Band 6 Administrator	19	£38	£700
HSE Senior Civil Servant Band 1	19	£97	£1,800
HSE Senior Civil Servant Band 2	19	£129	£2,400
TOTAL	**970**	**-**	**£108,300**

Note: totals may not sum due to rounding

9.2.3 Running the online portal

208. Having been set up as discussed in paragraph 200, the online portal would require ongoing IT resource to be maintained, serviced and updated. This has been estimated by the joint working group to cost around between around £36 thousand per annum and £60 thousand per annum, with a best estimate of around £48 thousand. An additional estimated £30 thousand per annum in online hosting charges would be incurred.

209. This ongoing cost would be borne from Year 1 to Year 9 of the appraisal period. This gives an **estimated present value cost to Government over ten years** of between around £502 thousand and £685 thousand, with a **best estimate of around £593 thousand.** This cost would be borne under Option 2.

9.2.4 Tripartite Consultation

210. The Directive requires adequate arrangements for operators and owners to contribute to tripartite consultation. HSE and DECC propose to use the existing Offshore Industry Advisory Committee (OIAC) as the most effective mechanism

for this. As this consultation and any preparatory work are within the current resources of the group and its secretariat, this is estimated to impose **no additional costs on the CA**.

9.2.5 Summary of Costs for Operating Offshore Competent Authority

211. Table 5 summarises the costs for operating the CA under Option 2. These costs would be borne by Government.

Table 5: Summary of costs for Operating Offshore CA (£thousands)

	Low	Best Estimate	High
CA Management Costs			
Managing new policies and procedures	£742	£824	£907
Running online portal	£502	£593	£685
Tripartite consultation	Nil	Nil	Nil
TOTAL	**£1,244**	**£1,418**	**£1,591**

Note: figures are ten-year present values. Totals may not sum due to rounding.

9.3 Costs for CA assessments related to HSE Legislation to implement the Directive

212. Costs for the CA assessing submissions related to HSE legislation would be recovered from industry through charging. The costs that follow are all recovered from industry, unless stated otherwise.

9.3.1 Offshore Gas Storage and Recovery

213. As explained in paragraphs 71 to 74, the definition of 'offshore installation' will be amended to remove gas storage in line with the Directive and to avoid potential gold plating. At present, the only installation engaged in gas storage offshore also produces hydrocarbon gas and will therefore be within scope of SCR 2015. No operations that would exclusively store gas offshore are expected in the future.

214. As such, this change of definition is estimated to produce **no costs or cost savings to HSE or the CA**.

9.3.2 Internal Waters

215. As explained in paragraphs 75 to 77, to prevent gold plating when implementing the Directive, HSE cannot apply the new SCR regime to internal waters and therefore proposes to maintain the existing SCR 2005 for regulating internal waters. As this would maintain the existing requirements for internal waters, this is estimated to impose **no cost on HSE or the CA**.

9.3.3 Internal Emergency Response Plans

216. The CA would be required to assess the description of the internal emergency response arrangements. The joint working group have estimated that each assessment would require the following resources, to be cost recovered from industry:

- around 2 hours of DECC Environmental Specialist time at an FEC of £122.17 per hour
- around 4 hours of HSE Band 2 Offshore Inspector time at an FEC of £120.32 per hour
- around 22.5 hours of HSE Band 3 Offshore Inspector time at an FEC of £108.34 per hour

217. This gives an additional cost per assessment of around £3.1 thousand. There would be a one-off cost for assessing all 386 installations' existing descriptions of IERPs by 2018 when they are required to become compliant. For simplicity, this cost is assumed to be distributed equally across 2016, 2017 and 2018. Adding a range of +/- 10%, this gives a **ten-year present value cost to be recovered from industry** of between around £1.0 million and £1.2 million, with a **best estimate of around £1.1 million**.

218. In addition, there would be an ongoing cost to the CA to assess the descriptions of the internal emergency response arrangements of new installations, of which there are estimated by HSE inspectors to be around 15 per annum on average, based on observation of the last three years' data. New installations and new well operations must comply with the new regulations by 2016, so this ongoing cost will be borne from Year 1 of the appraisal period until Year 9.

219. The additional cost required to assess new installations' descriptions of internal emergency response arrangements is estimated to be the same as for existing installations. Applying a range of +/- 10%, this gives an average annual cost to industry of between around £42 thousand and £51 thousand, with a best estimate of around £47 thousand.

220. This gives a **ten-year present value cost to be recovered from industry** of between around £320 thousand and £391 thousand, with a **best estimate of around £356 thousand**.

9.3.4 Independent Verification

221. The CA would be required to assess the additional information in installations' verification schemes as they are extended to cover environment-critical elements and to verify additional criteria. This will impose additional burdens on the CA to assess this further information.

222. The joint working group have estimated that this would not be a substantially greater burden as this is expected to only be a small increase in the scope of operators' schemes. They have estimated that each scheme would only require around 2 hours of DECC Environmental Specialist time at an FEC of £122.17 and around 7.5 hours of HSE Band 3 Offshore Inspector time at an FEC of £108.34. This gives a total cost per scheme of around £1 thousand and would be recovered from industry.

223. There would be a one-off cost of assessing all 386 existing installations' schemes by 2018 when they are required to become compliant. For simplicity, this cost is assumed to be distributed equally across 2016, 2017 and 2018. Adding a range of +/- 10%, this gives a **ten-year present value cost to be recovered from industry** of between around £334 thousand and £409 thousand, with a **best estimate of around £372 thousand.**

224. In addition, there would be an ongoing cost to assess new installations' verification schemes, of which there are estimated to be around 15 per annum on average. New installations must comply with the new regulations by 2016, so this ongoing cost would be borne from Year 1 of the appraisal period until Year 9.

225. The additional cost of assessing new installations' schemes is not estimated to be different from existing installations. Applying a range of +/- 10%, this gives an average annual cost to industry of between around £13.9 thousand and £17.0 thousand, with a best estimate of around £15.5 thousand.

226. This gives a **ten-year present value cost to be recovered from industry** of between around £106 thousand and £129 thousand, with a **best estimate of around £118 thousand**.

9.3.5 Corporate Major Accident Prevention Policy

227. The CA would be required to review Corporate Major Accident Prevention Policies (CMAPPs) and check that they fulfilled the Directive's requirements.

228. The joint working group have estimated that such a review would take around 2 hours of DECC Environmental Specialist time at an FEC of £122.17 per hour and around 11 hours of HSE Band 3 Offshore Inspector time at an FEC of £108.34 per hour. Adding a range of +/- 10%, this gives a total cost per CMAPP of between around £1.3 thousand and £1.6 thousand, with a best estimate of around £1.4 thousand and would be recovered from industry.

229. There would be a one-off cost of assessing the CMAPPs of the approximately 75 companies and contractors currently operating by 2018, when they are required to become compliant. For simplicity, this cost is assumed to be distributed equally across 2016, 2017 and 2018. This gives a **ten-year present value cost to be recovered from industry** of between around £91.3 thousand and £112 thousand, with a **best estimate of around £101 thousand**.

230. In the consultation stage IA, it was estimated that between 6 and 20 new companies per annum would begin operating on the UKCS and so require assessment of a new CMAPP. It was explained at that stage that this might be an overestimate as it was based on the number of new licensees as a proxy and not all licensees would be wholly new companies (i.e. they may already be operating on the UKCS) and so would not require a wholly new CMAPP.

231. Based on DECC's assessment of licensing applications, this final stage IA estimates that between 1 and 2 new companies would begin operating on the UKCS each year, each of which would require assessment of a CMAPP. This gives an annual average cost of between around £1.3 thousand and £3.2 thousand, with a best estimate of around £2.2 thousand. This would be borne from Year 1 of the appraisal period to Year 9 and be recovered from industry.

232. This gives a **ten-year present value cost to be recovered from industry** of between around £9.9 thousand and £24.2 thousand, with a **best estimate of around £16.5 thousand**.

9.3.6 Safety and Environmental Management System

233. The CA would be required to review and assess operators/owners' descriptions of their Safety and Environmental Management System (SEMS) when submitted as part of the safety case. Each review is estimated by the joint working group to require the following additional resources:

- around 6 hours of DECC Higher Executive Officer time at an FEC of £78.54 per hour
- around 4 hours of DECC Environmental Specialist time at an FEC of £122.17 per hour
- around 4 hours of HSE Band 2 Offshore Inspector time at an FEC of £120.32 per hour
- around 15 hours of HSE Band 3 Offshore Inspector time at an FEC of £108.34 per hour.

234. This gives an estimated cost per SEMS description of around £3.0 thousand and would be recovered from industry.

235. There would be a one-off cost of assessing all 386 existing installations' SEMS descriptions by 2018 when they are required to become compliant. For simplicity, this cost is assumed to be distributed equally across 2016, 2017 and 2018. Adding a range of +/- 10%, this gives a **ten-year present value cost to be recovered from industry** of between around £985 thousand and £1.2 million, with a **best estimate of around £1.1 million**.

236. In addition, there would be an ongoing requirement to review the SEMS as part of the safety case review for these 386 installations. However, HSE and DECC would anticipate **no additional costs** to review the safety and environmental elements of the SEMS.

237. Lastly, there would be an ongoing cost to assess new installations' SEMS descriptions, of which there are estimated to be around 15 per annum on average. New installations must comply with the new regulations by 2016, so this ongoing cost would be borne from Year 1 of the appraisal period until Year 9.

238. The additional cost of assessing new installations' SEMS descriptions is not estimated to be different from existing installations. Applying a range of +/- 10%, this gives an average annual cost to industry of between around £41.0 thousand and £50.1 thousand, with a best estimate of around £45.5 thousand.

239. This gives a **ten-year present value cost to be recovered from industry** of between around £312 thousand and £381 thousand, with a **best estimate of around £346 thousand**.

9.3.7 Safety cases

240. The CA would be required to review and assess additional information added to installations' safety cases. Each review is estimated by the joint working group to require the following resources:

- around 2 hours of DECC Environmental Specialist time at an FEC of £122.17 per hour
- around 4 hours of HSE Band 2 Offshore Inspector time at an FEC of £120.32 per hour
- around 11 hours of HSE Band 3 Offshore Inspector time at an FEC of £108.34 per hour.

241. This gives an estimated cost per safety case of around £1.9 thousand and would be recovered from industry.

242. There would be a one-off cost of assessing all 386 existing installations' safety cases by 2018 when they are required to become compliant. For simplicity, this cost is assumed to be distributed equally across 2016, 2017 and 2018. Adding a range of +/- 10%, this gives a **ten-year present value cost to be recovered from industry** of between around £621 thousand and £759 thousand, with a **best estimate of around £690 thousand**.

243. In addition, there would be an ongoing cost to assess new installations' safety cases, of which there are estimated to be around 15 per annum on average. New installations must comply with the new regulations by 2016, so this ongoing cost would be borne from Year 1 of the appraisal period until Year 9.

244. The additional cost of assessing new installations' schemes is not estimated to be different from existing installations. Applying a range of +/- 10%, this gives an average annual cost to industry of between around £25.8 thousand and £31.6 thousand, with a best estimate of around £28.7 thousand.

245. This gives a **ten-year present value cost to be recovered from industry** of between around £196 thousand and £240 thousand, with a **best estimate of around £218 thousand**.

9.3.8 Design and Relocation Notifications

246. The CA would be required to review and assess additional information added to installations' design and relocation notifications each time such a notification were submitted.

247. The joint working group estimated that for design notifications, which are submitted prior to construction of the installation, the additional information included would be at quite a high level and the additional work required to assess it would be minimal. As such, costs are assumed to be minimal in this estimation.

248. For each relocation notification, the joint working group estimated that the additional resources required to review would be around 4 hours of DECC Senior Executive Officer time at an FEC of £85.55 per hour and 7.5 hours of DECC Environmental Specialist time at an FEC of £122.17 per hour. This gives an estimated cost per assessment of around £1.2 thousand and would be recovered from industry.

249. In the consultation stage IA, the number of relocation notifications submitted per annum is estimated to be around 76, based on the last three years' data. However, in seeking to update this figure, it was found to be incorrect: 76 is the number of rig moves, rather than actual relocation notifications, which only need to be submitted in particular circumstances. In reality, HSE have only ever

received two notifications. As a simplifying assumption, this analysis will assume that one submission will be made each year.

250. Adding a range of +/- 10%, this gives an estimated annual average estimated cost to industry of between around £1.1 thousand and £1.4 thousand, with a best estimate of around £1.2 thousand. This would be borne from Year 1 of the appraisal period to Year 9.

251. This gives a **ten-year present value cost to be recovered from industry** of between around £8.5 thousand and £10.4 thousand, with a **best estimate of around £9.4 thousand**.

9.3.9 Well Notifications

252. The CA would be required to review and assess additional information added to installations' well notifications each time such a notification were submitted. For each notification, the joint working group estimated that the additional resources required to review would be around 7.5 hours of HSE Band 3 Offshore Inspector time at an FEC of £108.34 per hour. This gives an estimated cost per assessment of around £810 and would be recovered from industry.

253. Based on the last three years' data the estimated number of well notifications submitted per annum is estimated to be around 550. Adding a range of +/- 10%, this gives an estimated annual average estimated cost to industry of between around £402 thousand and £492 thousand, with a best estimate of around £447 thousand. This would be borne from Year 1 of the appraisal period to Year 9.

254. This gives a **ten-year present value cost to be recovered from industry** of between around £3.1 million and £3.7 million, with a **best estimate of around £3.4 million**.

9.3.10 Combined Operations Notifications

255. The CA would be required to review and assess additional information added to installations' combined operations notifications each time such a notification were submitted. However, the joint working group have estimated that the additional information is so little as to require no additional work. As such, this requirement is estimated to generate **no additional cost**.

9.3.11 Dismantling a Fixed Production Installation

256. The CA would be required to review and assess additional information added to installations' safety cases for installations being dismantled each time such a safety case were submitted. For each safety case, the joint working group estimated that the additional resources required to review would be as follows:

- around 2 hours of DECC Environmental Specialist time at an FEC of £122.17 per hour
- around 7.5 hours of HSE Band 2 Offshore Inspector time at an FEC of £120.32 per hour
- around 22.5 hours of HSE Band 3 Offshore Inspector time at an FEC of £108.34 per hour.

257. Adding a range of +/- 10%, this gives an estimated cost per assessment of between £3.2 thousand and £3.9 thousand, with a best estimate of around £3.6 thousand and would be recovered from industry.

258. Based on estimates from DECC's Decommissioning Team, the number of installations expected to commence decommissioning and so need to submit a decommissioning safety case over the next ten years is estimated to be around 15 per annum. This gives an annual average cost to industry of between around £48.4 thousand and £59.1 thousand, with a best estimate of around £53.8 thousand. This would be borne from Year 1 of the appraisal period to Year 9.

259. This gives a **ten-year present value cost to be recovered from industry** of between around £368 thousand and £450 thousand, with a **best estimate of around £409 thousand**.

9.3.12 Reporting imminent danger or increased risks of a major accident

260. The CA would be required to review and assess reports from industry on situations where they have had to take action when operations posed an immediate danger to human health or significantly increased the risk of a major accident, and where there was immediate risk of a major accident. However, the joint working group have estimated that this would not impose any burden beyond work that would be completed anyway. As such, this requirement is estimated to generate **no additional cost**.

9.3.13 Reporting major accidents outside the EU

261. The CA would request reports from UK-registered companies regarding major accidents occurring outside of the European Union (EU). The joint working group have estimated that they would request only around 1.5 reports per annum on average, due to the infrequent nature of major accidents and the fact that only UK-registered companies would be in scope. For each report, the joint working group estimated that the additional resources required to receive and review would be as follows:

- around 15 hours of HSE Band 2 Offshore Inspector time at an FEC of £120.32 per hour
- around 30 hours of HSE Band 3 Offshore Inspector time at an FEC of £108.34 per hour
- around 4 hours of HSE Band 6 Administrator time at an FEC of £37.86 per hour

262. Adding a range of +/- 10%, this gives an estimated annual cost of between around £7 thousand and £8.6 thousand, with a best estimate of around £7.8 thousand and would be recovered from industry. This cost would be borne form Year 1 of the appraisal period to Year 9.

263. This gives a **ten-year present value cost to be recovered from industry** of between around £53 thousand and £65 thousand, with a **best estimate of around £59 thousand**.

9.3.14 Safety Zones

264. For the new provisions on granting permission for vessels to enter safety zones, the joint working group estimated there would be no impact on practice and so **no costs or savings**.

9.3.15 Implementing Act on data reporting criteria and format

265. HSE estimate that they would receive between around 145 and 176 additional reports against the new criteria, with a best estimate of around 160 per annum, based on the current level of reporting and consideration of the type of events that would be reportable. This assumption has been unanimously agreed in follow-up interviews with the research group. The resources estimated to process reports once received, based on the current experience under RIDDOR, is around 15 minutes each for a Band 2 Administrator at an FEC of £73.30 per hour and a Band 6 Administrator at an FEC of £37.86 per hour. This gives an annual average cost of between about £4 thousand and £4.9 thousand, with a best estimate of around £4.4 thousand.

266. In addition, HSE would be required to produce a report to the Commission each year on report statistics. HSE have estimated that the resources to do this would be similar to those currently incurred to produce reports on RIDDOR. That is, between around 38 hours and 46 hours, with a best estimate of around 42 hours, spent by each of a Band 3 Offshore Inspector at an FEC of £108.34 and a Band 1 Offshore Inspector at an FEC of £129.45. This gives an annual average cost of between around £9 thousand and £11 thousand, with a best estimate of around £10 thousand.

267. This ongoing cost would be borne from Year 1 to Year 9 of the appraisal period and be recovered from industry. This gives a **ten-year present value cost to be recovered from industry** of between around £98.8 thousand and £121 thousand, with a **best estimate of around £110 thousand**.

9.3.16 Offshore Oil and Gas Authorities Group (EUOAG)

268. Following implementation, the CA would send an additional delegate to the EUOAG working group, which meets around three times per year. This is estimated to require around 113 hours each year of an HSE Band 2 Regulatory Inspector's time at and FEC of £74.30 per hour, plus around £1,500 in travel and subsistence costs per annum.

269. Adding a range of +/- 10%, this gives an estimated annual average cost per annum of between around £9 thousand and £11 thousand, with a best estimate of around £10 thousand and would be recovered from industry. This would be borne from Year 1 of the appraisal period to Year 9.

270. This gives a **ten-year present value cost to be recovered from industry** of between around £69 thousand and £81 thousand, with a **best estimate of around £75 thousand**.

9.3.17 Summary of CA Costs for Assessments related to Changes in HSE Legislation

271. Table 6 summarises the costs to be recovered from industry from CA assessments related to changes in HSE legislation.

Table 6: Summary of CA costs for assessments related to changes in HSE legislation (£thousands)

	Low	Best Estimate	High
Internal Emergency Response Plans	£1,332	£1,480	£1,628
Independent Verification	£440	£489	£538
Corporate Major Accident Prevention Policy	£101	£118	£136
Safety and Environmental Management Systems	£1,297	£1,441	£1,585
Safety Cases	£818	£909	£999
Design and Relocation Notifications	£8	£9	£10
Well Notifications	£3,060	£3,400	£3,740
Dismantling a fixed installation	£368	£409	£450
Reporting major accidents outside the EU	£53	£59	£65
Implementing Act on data reporting criteria and format	£99	£110	£121
Offshore Oil & Gas Authorities Group	£69	£75	£81
Combined Operations Notifications	Nil	Nil	Nil
Reporting imminent danger or increased risk of a major accident	Nil	Nil	Nil
Safety Zones	Nil	Nil	Nil
Offshore gas storage and recovery	Nil	Nil	Nil
Internal waters	Nil	Nil	Nil
Total	**£7,645**	**£8,499**	**£9,354**

Note: figures are ten-year present values. Totals may not sum due to rounding.

9.4 Costs for CA assessments related to DECC Environmental Legislation to implement the Directive

272. This part of the Impact Assessment outlines the additional CA costs relating to the changes to DECC's offshore environmental legislative regimes required to implement the Directive. These costs would all be recovered from industry, unless otherwise stated.

273. Table 7, below, sets out the FEC rates for the DECC personnel that will be involved with various duties imposed by the Directive.

Table 7: Salaries and Full Economic Costs (FECs) for DECC personnel

Grade	Daily Rate (FEC)	Hourly Rate (FEC)
Environmental Specialist	£916.26	£122.17
Senior Executive Officer (SEO)	£641.63	£85.55
Higher Executive Officer (HEO)	£589.05	£78.54
Executive Officer (EO)	£541.70	£72.23

9.4.1 Amendments to the OPRC Regulations

274. Workloads relating to changes to the OPRC Regulations to meet the Directive requirements for the 10 year assessment period are summarised below:

- New Oil Pollution Emergency Plans (OPEPs) for new Production Installation decommissioning operations from 2015 to 2024.
- Review OPEPs for existing Production Installations by 2018.
- Assessing existing OPEPs earlier than expected from 2016 to 2023
- New OPEPs for new Production Installations from 2015 to 2024.
- Review of new OPEPs for Production Installations five years after initial preparation during the period from 2015 to 2024 (one review for each OPEP)
- New OPEPs for existing Non-Production Installations, including MODUs / Intervention Vessels, from 2015 to 2016
- New OPEPs for new Non-Production Installations, including MODUs / Intervention Vessels, from 2015 to 2024
- Review of new OPEPs for Non-Production Installations five years after initial preparation during the period 2015 to 2024 (one review for each OPEP)
- New OPEP Addenda for well operations from 2015 to 2024.
- New OPEP Addenda for combined well operations from 2015 to 2024.

275. The requirements and associated costs relating to specific Directive obligations are outlined below.

9.4.1.1 Extend the OPEP requirements (as part of the Directive obligation to produce an Internal Emergency Response Plan (IERP)) to include the decommissioning of offshore installations

276. OPEPs for new decommissioning activity will have to be submitted and approved as soon as the new regulation comes into force (i.e. from 2015 until 2024). OPEPs for decommissioning activity would be time-limited and would expire when the decommissioning operations were completed, so there would not be a regular review requirement.

277. There is a significant amount of uncertainty as to the actual pace of decommissioning operations per year, due to certain factors such as the oil price e.g. a sudden increase in the price of a barrel of oil can lead to the deferral of proposed decommissioning plans by many years. Based on information currently available to DECC on expected future decommissioning activities on the United Kingdom Continental Shelf, it is at presently anticipated that, from 2015, approximately 15 installations per year will cease operations and three will be

removed within a year of cessation of operations, with the remainder being subject to longer more complex decommissioning activities which could take many years before all structures and associated infrastructure are fully removed.

278. DECC assumptions for assessing / approving decommissioning OPEPs during 2015 to 2024 are the following:

- Each year, DECC would need to review 15 OPEPs pertaining to potential decommissioning operations.

- Based on estimates from the staff who would carry out the work, the resource implications for DECC in assessing / approving the decommissioning OPEPs are**:**

- Environmental Specialist**:**

- ➢ Time required for assessing / approving one decommissioning OPEP would be 1 day at a day rate of £916.26
- ➢ 15 days required to assess / approve 15 OPEPs

279. Total annual costs to DECC to be recovered from industry for assessing and approving decommissioning OPEPs (calculated by deploying a low (-10%) / best estimate (medium) / high (+10%) approach) are the following:

The **NPV of the total costs to be recovered from industry** for undertaking the review and approval of 15 decommissioning OPEPs per year during the 10-year period 2015 and 2024 would be between £106 thousand and £130 thousand with a **best estimate of £118 thousand**.

9.4.1.2 Amend the OPEP requirements for Production Installations (as part of the Directive's obligations to produce an IERP)

280. **Existing OPEPs for Production Installations:** Production OPEPs can cover one or more fields, and will cover all the production installations associated with that field or fields. One OPEP could therefore cover a number of production installations. DECC will have to liaise with HSE to find out which production installations require / have a safety case, and then assign the relevant OPEP to all the relevant installations.

281. There are currently 101 existing Production Installation OPEPs that will all need to be updated by 2018 (e.g. to reflect the new Directive requirements relating to inventories of response equipment and the effectiveness of response plans), and future reviews will have to be aligned with the Safety Case review timetable. The implementation of the Directive will therefore result in a requirement to review the 101 existing production OPEPs including the additional elements required by the Directive by 2018, whereas the review process would normally have been spread over a five-year period under present legislation.

282. It is currently projected that a total of 9 installations could be removed by decommissioning activities by 2018, potentially reducing the total number of existing OPEPs to 92.

283. DECC assumptions for reviewing / re-approving additional elements in existing OPEPs for Production Installations by 2018 *(Transitional element)* are the following:

- 92 existing OPEPs would be submitted to DECC for review

- Based on estimates from the staff who would carry out the work, the resource implications for DECC in reviewing / re-approving 92 existing OPEPs are**:**

Environmental Specialist**:**

- Time required for reviewing / re-approving one existing OPEP would be 0.50 days at a half-daily rate of £458.13.

- 46 days required to review / re-approve 92 existing Production Installation OPEPs by 2018.

284. Total costs to DECC to be recovered from industry for reviewing and re-approving existing OPEPs for Production Installations by 2018 (calculated by deploying a low (-10%) / best estimate (medium) / high (+10%) approach)

The **NPV of the total costs to be recovered from industry** for undertaking the review / re-approval of existing OPEPs by 2018 would be between £35.4 thousand and £43.3 thousand with a **best estimate of £39.4 thousand**.

285. **'Bringing forward' reviews of existing OPEPs for Production Installations:** As part of the alignment of the OPEP and safety case review cycle, explained in paragraph 281, the OPEP review cycle will need to be brought in line with the safety case review cycle. This will result in the existing elements of some production installations' OPEPs being reviewed earlier than they otherwise would.

286. This means that the new elements of the OPEP will need to be reviewed and this will represent a wholly new cost (as described in paragraphs 280 to 284. However, the rest of the OPEP would need to be reviewed at some point anyway, but alignment of the review cycle with that of the safety case means that in some cases it will need to be reviewed earlier than it otherwise would have been under the baseline.[17] Due to the effect of discounting, in net present value terms this leads to additional costs as the closer to the present, the greater we value a given cost or benefit.[18]

287. Based on DECC's analysis of OPEP review cycles, it is estimated that around 45 existing OPEPs would have their reviews brought forward in this manner and that the average 'brought forward' period would be just over two years. This means that around 45 existing OPEPs will now be reviewed in the period 2016 to 2018, when they otherwise would have been reviewed in the period 2018 to 2020.

288. In addition, this will also mean that 15 of these 45 OPEPs (i.e. one year's worth) will now require an additional review during the course of the appraisal

[17] Please note that this is also a separate issue from the costs of subsequent review of the *wholly new* OPEP elements for production installations, described in paragraphs 296 to 300.
[18] This is in-line with guidelines on inter-temporal discounting in HMT's Green Book.

period (2015-2024). This is because if their review schedule were not brought forward in this way, the later reviews would fall after the cut-off year, i.e. from 2025 onwards.

289. DECC have estimated that the resource to review the existing OPEP would be around half a day of an Environmental Specialist for each OPEP at a half-day FEC of £458.13.

290. For simplicity, the 45 OPEP reviews are assumed to be spread evenly over a three-year period.

291. Table 8 summarises the expected costs under the baseline and under Option 2.

Table 8: Summary of change in existing OPEP review cycles for production installations

	Costs			
Year	**Baseline**	**Option 2**	***Option 2 ('brought forward' element only)***	***Option 2 (additional review only)***
2015	£0	£0	*£0*	*£0*
2016	£0	£6,900	*£6,900*	*£0*
2017	£0	£6,900	*£6,900*	*£0*
2018	£6,900	£6,900	*£6,900*	*£0*
2019	£6,900	£0	*£0*	*£0*
2020	£6,900	£0	*£0*	*£0*
2021	£0	£6,900	*£6,900*	*£0*
2022	£0	£6,900	*£6,900*	*£0*
2023	£6,900	£6,900	*£0*	*£6,900*
2024	£6,900	£0	*£0*	*£0*
Present Value	**£28,200**	**£35,500**	***£30,200***	***£5,200***
Difference from Baseline PV	**-**	**£7,300**	**£2,000**	**£5,200**

Note: totals may not sum due to rounding

292. This shows an additional **ten-year present values cost to be recovered from industry of around £7.3 thousand**. This is mostly driven by the cost of the additional review of around £5.2 thousand, rather than the cost (or discounting effect) bringing forward all reviews of around £2 thousand.

293. **<u>New OPEPs for new Production Installations</u>:** Based on data collated by DECC and HSE on new developments over recent years, it is estimated that 4 new OPEPs will be required per year from 2015 to 2024 to cover new Production Installations. During the 10-year appraisal period, DECC will therefore have to review and approve a total of 40 OPEPs for new Production Installations.

294. DECC assumptions for assessing/approving new OPEPs for Production installations from 2015 to 2024 are the following.

- 40 OPEPs for new Production Installations are expected to be submitted to DECC.

- Based on estimates from the staff who would carry out the work, the resource implications for DECC in assessing / approving the new Production Installation OPEPs are**:**

Environmental Specialist**:**

- Time required for assessing / approving one OPEP would be 1 day at a day rate of £916.26.

- 40 days required to assess / approve 40 new OPEPs from 2015 to 2024.

295. Total costs to DECC to be recovered from industry for assessing/approving OPEPs for new Production installations from 2015 to 2024 (calculated by deploying a low (-10%) / best estimate (medium) / high (+10%) approach) are the following:

The **NPV of the total costs to be recovered from industry** for undertaking for assessing/approving OPEPs for new Production installations from 2015 to 2024 would be between £28.4 thousand and £34.7 thousand with a **best estimate of £31.5 thousand**.

296. **Subsequent five-yearly reviews of Production Installation OPEPs:** Taking into consideration the fact that over the timescale of 2015 to 2024:

- 150 installations will cease operations, of which approximately 30 will be fully decommissioned and removed from the UKCS;

- It is assumed that 30 OPEPs would be permanently removed by 2024; and

- 40 new Production Installations are expected to come on stream (and, at this juncture, it is highly unlikely that any of these new Production Installations would be decommissioned prior to 2024),

297. It is estimated that during the 10-year appraisal period, 91 OPEPs for Production Installations would be subject to their five-yearly review. This is based on the current 101 Production Installation OPEPs and adjusting for the 30 Production Installations expected to complete decommissioning work over the appraisal period and half of the 40 new Production Installations expected to begin work over the same period (i.e. those commencing operation in 2015 to 2019).

298. There could also be instances where existing Production Installation OPEPs might be submitted to DECC for review as a result of material changes to an installation's operations e.g. a new field being connected to a floating vessel or platform ('tied-back') and added to the OPEP. However, it is impossible to estimate whether this would have a significant effect on the review cycle. It also has to be borne in mind that the DECC OPEP review cycle will have to be aligned with the HSE safety case review cycle, and this could also have an effect on the review cycle. For the purpose of this Impact Assessment, it is therefore assumed for simplicity that there would be one full five-yearly review cycle for 91 OPEPs

during the period up to 2024 and that these would be spread evenly over that period. In reality the timing of the creation/update of the Production Installation OPEPs, described above, would result in a greater concentration of reviews in some years than others. However, it has not been possible to estimate the impact of this at this stage due to uncertainties around the alignment of the OPEP review cycle with the safety case review cycle and the impacts of decommissioning work.

299. DECC assumptions for reviewing / re-approving OPEPs for Production installations under five-yearly review cycle are the following:

- Based on estimates from the staff who would carry out the work, the resource implications for DECC in carrying out the review of 91 Production Installation OPEPs would be**:**

Environmental Specialist:

- Time required for reviewing one OPEP would be 0.50 days at a half-day rate of £458.13
.
- 45.5 days required for reviewing / re-approving 91 Production Installation OPEPs over the period 2020 to 2024.

300. Total costs to DECC to be recovered from industry for reviewing and re-approving OPEPs for Production Installations under the five year review process from 2020 to 2024 (calculated by deploying a low (-10%) / best estimate (medium) / high (+10%) approach) are the following:

The **NPV of the total costs to be recovered from industry** for undertaking the review / re-approval of OPEPs under the five year review process up to 2024 would be between £29.5 thousand and £36.1 thousand with a **best estimate of £32.8 thousand.**

9.4.1.3 Extend the OPEP requirements (as part of the Directive obligation to produce an IERP) to the owners of Non-production Installations

301. Responsibility for the development and maintenance of an OPEP will be extended to the owners of non-production installations.

302. **New OPEPs for existing Non-production Installations:** There are currently 106 non-production installations, e.g. Mobile Drilling Units (MoDUs) / Intervention Vessels / Flotels (i.e. floating accommodation units), operating in UK waters. The owners of these installations will be required to prepare OPEPs that will have to be submitted to DECC and approved within a year of the new regulations coming into force i.e. by July 2016. This will be new work directly related to implementation of the Directive.

303. DECC assumptions for assessing and approving new OPEPs for existing Non-production Installations by 2016 *(Transitional element)* are the following:

- There will be 106 new OPEPs submitted for approval during 2015 and 2016

Based on estimates from the staff who would carry out the work, the resource implications for DECC in assessing / approving the new OPEPs are:

Environmental Specialist**:**

- Time required for assessing / approving one OPEP would be one day at a day rate of £916.26.
- 106 days required for assessing approving 106 new OPEPs by 2016

304. Costs to DECC to be recovered from industry for assessing and approving new OPEPs for Non-production installations by 2016 (calculated by deploying a low (-10%) / best estimate (medium) / high (+10%) approach) are the following:

The **NPV of the total costs to be recovered from industry** for undertaking the assessment / approval of 106 new OPEPs by 2016 would be between £85.9 thousand and £105 thousand with a **best estimate of £95.5 thousand**.

305. **New OPEPs for new Non-Production Installations:** Based on data collated by DECC and HSE on new non-production installations operating in the UKCS over recent years, it is estimated that 5 new OPEPs will be required per year from 2015 to 2024 to cover new non-production installations. However, as non-production installations move around the UKCS, this figure might be overestimated. It has not been possible to estimate how significant this overestimation might be, but given the small number of new OPEPs for non-production installations, it is expected to be small. From 2015 to 2024, we will assume DECC will therefore have to review and approve a total of 50 OPEPs for new non-production installations.

306. DECC assumptions for assessing and approving new OPEPs for new Non-production Installations from 2015-2024 are the following**:**

- There will be 50 new OPEPs submitted for approval during the period 2015 to 2024

- Based on estimates from the staff who would carry out the work, the resource implications for DECC in assessing / approving the new OPEPs are:

Environmental Specialist**:**

- Time required for assessing / approving one OPEP would be one day at a day rate of £916.26.
- 50 days required for assessing approving 50 new OPEPs by 2024

307. Costs to DECC to be recovered from industry for assessing and approving new OPEPs for Non-production installations from 2015 to 2024 (calculated by deploying a low (-10%) / best estimate (medium) / high (+10%) approach) are the following:

The **NPV of the total costs to be recovered from industry** for undertaking the assessment / approval of 50 new OPEPs by 2024 would be between £31.3 thousand and £38.2 thousand with a **best estimate of £34.7 thousand**.

308. **Subsequent five-yearly reviews of OPEPs for Non-production Installations:** The 106 new OPEPs for Non-production Installations would have to be reviewed on a five-yearly cycle that would have to be aligned with the safety case review cycle. In addition, half of the 50 new NPI OPEPs would also have to be reviewed during the appraisal period (i.e. those created during 2015 to 2019). This gives 131 in total.

309. At this juncture, it is assumed that it is unlikely that there would be a material change to force an early review, and that every OPEP for a Non-production Installation will be reviewed once during the period 2020 up to 2024. It is assumed for simplicity that these reviews would be spread evenly over this period, but in reality the timing of the creation/update of the Non-Production Installation OPEPs, described above, would result in a greater concentration of reviews in some years than others. However, it has not been possible to estimate the impact of this due to uncertainties around the alignment of the OPEP review cycle with the safety case review cycle and the impacts of decommissioning work.

310. DECC assumptions for reviewing and re-approving OPEPs for Non-production installations up to 2024 are the following:

- Based on estimates from the staff who would carry out the work, the resource implications for DECC in reviewing / re-approving existing OPEPs are**:**

Environmental Specialist**:**

- Time review and re-approve one OPEP would be 0.5 days at a half-day rate of £458.13.
- 65.5 days required to review 131 Non-production Installation OPEPs; during the period up to 2024.

311. Total costs to DECC to be recovered from industry for assessing and re-approving OPEPs for Non-production installations from 2020 up to 2024 (calculated by deploying a low (-10%) / best estimate (medium) / high (+10%) approach) are the following.

The **NPV of the total costs to be recovered from industry** for undertaking the review / approval of Non-production Installation OPEPs up to 2024 would be between £42.5 thousand and £52.0 thousand with a **best estimate of £47.2 thousand**.

312. **Well operations:** There is a requirement for the OPEP to be amended to take into account any additional risks identified for proposed well operations, prior to those operations commencing. For well operations involving Non-production Installations, the operator undertaking the well operations will be responsible for preparing an addendum to the owner's plan to cover specific well operations or groups of well operations. Similar addenda are already required for well operations undertaken from Production Installations. The addenda would be time-limited and would expire when the well operations were completed, so there would not be a regular review requirement. Based on well operations applications (drilling, intervention and abandonment) received by DECC in recent years, it is

anticipated that 300 well operations addenda will be submitted each year from 2015 to 2024.

313. DECC assumptions for assessing / approving ‘well operation’ addenda (2015 to 2024) are the following:

- Each year, 300 ‘well operations’ addenda will be submitted to DECC for review.

- Based on estimates from the staff who would carry out the work, the resource implications for DECC in assessing / approving the ‘well operation’ addenda are**:**

Environmental Specialist**:**

- Time required for assessing / approving one ‘well operation’ addendum would be 0.25 days at a quarter-day rate of £229.06.

- 75 days required to assess / approve 300 ‘well operations’ addenda per year. Over 10 years this would equate to 750 days to deal with 3,000 addenda.

314. Total costs to DECC to be recovered from industry for assessing and approving ‘well operation’ addenda during the period 2015 to 2024 (calculated by deploying a low (-10%) / best estimate (medium) / high (+10%) approach) are the following

The **NPV of the total costs to be recovered from industry** for assessing / approving ‘well operation’ addenda from 2015 to 2024 would be would be between £532 thousand and £651 thousand with a **best estimate of £592 thousand**.

315. **Combined Operations:** Addenda to the Production Installation and Non-production Installation OPEPs will be required to cover all combined operations (e.g. well operations and accommodation requirements). The addenda would be time-limited and would expire when the operations were completed, so there would not be a regular review requirement. The addenda to the Production Installation OPEPs are a current requirement and the addenda to the Non-production Installation OPEPs would be broadly similar. Each year around 61 combined operations notifications are submitted to HSE, based on data from the last three years. Not all of these will require an individual OPEP addendum as some OPEPs cover more than one combined operation. As such, based on combined operations addenda received by DECC in recent years, it is anticipated that 40 addenda for ‘combined operations’ (additional to the well operations addenda) will be submitted each year from 2015 to 2024.

316. DECC assumptions for assessing / approving ‘combined operations’ addenda during the period 2015 to 2024 are the following:

- Each year, 40 ‘combined operations’ addenda will be submitted to DECC.

- Based on estimates from the staff who would carry out the work, the resource implications for DECC in assessing / approving the ‘combined well operation’ addenda are**:**

Environmental Specialist**:**

- Time required for assessing / approving one ‘combined operations’ addendum would be 0.25 days at a quarter-day rate of £229.06

- 10 days required to assess / approve 40 ‘combined operations’ addenda per year. Over 10 years this would equate to 100 days to deal with 400 addenda.

317. Total costs to DECC to be recovered from industry for assessing and approving ‘combined operations’ addenda during the period 2015 to 2024 (calculated by deploying a low (-10%) / best estimate (medium) / high (+10%) approach) are the following:

The **NPV of the total costs to be recovered from industry** for assessing / approving ‘combined operations’ addenda during the period 2015 to 2024 would be between £71.0 thousand and £86.8 thousand with a **best estimate of £78.9 thousand**.

9.4.1.4 Preparedness for the implementation of the plan and interaction with the external emergency response plan

318. Operators and owners are required to undertake OPEP exercises and to retain evidence of the exercises undertaken both onshore and offshore and to provide that evidence on request. Exercises are a current requirement and there are considered to be no additional administrative or financial burdens for the CA. In response to the public consultation 78% agreed that carrying out and retaining evidence of OPEP exercises will not result in any additional costs to industry.

9.4.1.5 Powers of Inspectors to prohibit operations where no OPEP is in place, or where the plan is deemed insufficient or the requirements of the plan are not being met

319. Appointed Inspectors will be able to serve notices as and when deemed appropriate. Whilst there are already procedures in place that would prevent the issue of other approvals if there was no OPEP in place, or the OPEP was unacceptable, it is theoretically possible that DECC would use the new provisions to prohibit an activity if an offshore inspection confirmed that trained staff / equipment requirements referred to in an OPEP were not being met. However, in reality it is highly unlikely that this would happen and so this is estimated to impose **no cost on industry or the regulator**.

9.4.2 Financial liability arrangements

320. Based on the number of development wells drilled in recent years, expanding the scope of the financial responsibility provisions to wells other than exploration and appraisal wells will result in approximately 50 additional reviews per year.

321. DECC assumptions for undertaking financial reviews every year from 2015 to 2024 are the following:

- Based on estimates from the staff who would carry out the work, the resource implications for DECC in undertaking 50 additional financial reviews every year are:

SEO**:**

- Time required for undertaking one financial assessment review would be 2 hours at a total cost of £171.10.
- 135 days required to review 500 financial assessments at a daily rate of £641.63 during the period 2015 to 2024.

HEO**:**

- Time required for undertaking one financial assessment review would be 2 hours at a total cost of £157.08.
- 135 days required to review 500 financial assessments at a daily rate of £589.05 during the period 2015 to 2024.

EO**:**

- Time required for undertaking one financial assessment review would be 3 hours at a total cost of £216.69.
- 203 days required to review 500 financial assessments at a daily rate of £541.70 during the period 2015 to 2024.

322. Costs to DECC to be recovered from industry for assessing and accepting 'combined operation' descriptions from 2016 to 2024 (calculated by deploying a low (-10%) / best estimate (medium) / high (+10%) approach) are the following:

The **NPV of the total costs to be recovered from industry** for reviewing financial data from 2015 to 2024 would be between £211 thousand and £258 thousand with a **best estimate of £234 thousand**.

9.4.3 Summary of costs for CA assessments related to changes in DECC Environmental legislation to implement the Directive

323. Table 9 summarises the costs of the CA for assessments relate to changes to DECC environmental legislation, all of which would be recovered from industry.

Table 9: Summary of CA costs for assessments related to changes in DECC environmental legislation, to be recovered from industry (£thousands)

	Low	**Best Estimate**	**High**
OPEPs			
Decommissioning OPEPs	£106	£118	£130
Amendments to OPEPs for Production Installations	£101	£111	£121
Extending OPEPs to Non-Production Installations	£160	£177	£195
Well Operation OPEPs	£532	£592	£651
Combined Operations OPEPs	£71	£79	£87
OPEP Issuing Prohibition Notices	Nil	Nil	Nil
OPEP Exercises	Nil	Nil	Nil
Financial Liability Arrangements	£211	£234	£258
Total	**£1,181**	**£1,312**	**£1,442**

Note: figures are ten-year present values. Totals may not sum due to rounding.

9.5 Costs for CA and Licensing Authority assessments related to changes to DECC Licensing Legislation to implement the Directive

324. For the purpose of estimating the additional costs relating to the licensing and operatorship provisions, it has been assumed that there will be no change to the existing technical and financial assessments undertaken for licence applications. The estimates of additional costs therefore relate to the preparation of the environmental and safety submissions that will be required to support licence applications and operator appointments.

325. The first phase of the assessment involved estimating the baseline costs to industry of preparing the environmental submissions required to support current licence applications. The second phase sought to estimate the additional costs to industry relating to any changes in the environmental submission requirements and the new safety submission requirements for licensing as a consequence of the Directive requirements. Because of the likely similarity in the competency and capacity requirements for licence applicants and operatorship appointees, it was then assumed that the total cost of the amended environmental submission and the new safety submission would also be incurred in relation to operatorship appointments.

326. As the original consultation proposals were based on a single operator model, industry focus groups were not invited to participate in any cost estimation exercise relating to the licensing and operatorship provisions of the Directive for inclusion in the consultation stage IA, as it was felt that any changes to implement the single operator model would be immaterial and the costs were therefore assumed to be zero. That conclusion is no longer valid given the significant changes relating to the adoption of a multiple operatorship model, and

DECC therefore contacted a sample group of operators, duty holders and consultants to test the estimates of the current baseline costs and the additional costs relating to the Directive requirements.

9.5.1 Licensing (Costs recovered by the CA)

327. Costs are based on estimates of approximately 180 licence applications during each biannual licensing round, and it is considered that approximately 10 of the applications will relate to new licence applicants. These estimates are based on the number of applications and the number of new applicants during recent licensing rounds.

328. During the first licensing round following implementation of the Directive, all applicants will have to prepare submissions that satisfy the new Directive requirements, but during subsequent licensing rounds existing licensees will only have to update their submissions, whereas new licence applicants will have to prepare submissions to fully satisfy the new information requirements. Based on those assumptions, and for the purpose of the IA, the estimated number of new and updated submissions during the 10 year appraisal period are therefore summarised in Table 10.

Table 10: Forecast number of new and updated licensing submissions 2015 - 2024

Year	No. of new submissions	No. of updated submissions
Year 0 (2015)	0	0
Year 1 (2016)	180	0
Year 2 (2017)	0	0
Year 3 (2018)	10	170
Year 4 (2019)	0	0
Year 5 (2020)	10	170
Year 6 (2021)	0	0
Year 7 (2022)	10	170
Year 8 (2023)	0	0
Year 9 (2024)	10	170

329. The time required on the part of the CA to make these assessments for new submissions has been estimated by DECC based on current review procedures. The HSE review process is still to be designed, but the CA working group have made some initial estimates. They are as follows:

- around 7.5 hours of DECC Environmental Specialist time at an FEC of £122.17 per hour
- around 2 hours of DECC Senior Environmental Specialist time at an FEC of £127.71 per hour
- around 2 hours of DECC Higher Executive Officer time at an FEC of around £78.54 per hour
- around 2 hours of HSE Band 1 Offshore Inspector time at an FEC of £129.45 per hour
- around 37.5 hours of HSE Band 3 Offshore Inspector time at an FEC of £108.34 per hour
- around 2 hours of HSE Band 4 Administrative Officer time at an FEC of £50.67 per hour

330. This gives an average cost per assessment of around £5.8 thousand. Across the new submissions in Table 10, this gives a **ten-year present value cost to be recovered from industry** of between around £1.1 million and £1.3 million, with a **best estimate of around £1.2 million**.

331. The time required on the part of the CA to assess updated submissions has been estimated by DECC and HSE as follows:

- around 3.75 hours of DECC Environmental Specialist time at an FEC of £122.17 per hour
- around 2 hours of DECC Senior Environmental Specialist time at an FEC of £127.71 per hour
- around 2 hours of DECC Higher Executive Officer time at an FEC of around £78.54 per hour
- around 2 hours of HSE Band 1 Offshore Inspector time at an FEC of £129.45 per hour
- around 15 hours of HSE Band 3 Offshore Inspector time at an FEC of £108.34 per hour
- around 2 hours of HSE Band 4 Administrative Officer time at an FEC of £50.67 per hour

332. This gives an average cost per assessment of around £2.9 thousand. Across the updated submissions in Table 10, this gives a **ten-year present value cost to be recovered from industry** of between around £1.4 million and £1.7 million, with a **best estimate of around £1.6 million**.

9.5.2 Licensing (Costs to the Licensing Authority)

333. In addition to the Competent Authority costs in paragraphs 327 to 332, there will be costs to the Licensing Authority relating to administration of the licensing process, and IT costs relating to updating the licence application portal, called 'LARRY' (Licensing Applications Repository), to include the HSE in the licence application consultation process. As the licensing process is mediated via the Portal, the cost in terms of additional administrative staff time is considered to be immaterial. However, the IT system (i.e. the Portal) will require amendment to accommodate the revised consultation process and this will cost **approximately £20 thousand**. These costs will be absorbed by the Licensing Authority and not recovered from industry.

9.5.3 Operatorship (Costs recovered by the Competent Authority)

334. The vast majority of licensee groups currently appoint a single company, the licence operator, to execute all oil and gas activities under the licence, and it is considered unlikely that this will change following implementation of the Directive. The submissions required to support these appointments will continue to be included in the licence applications and Field Development Plan applications, and it is assumed that any additional costs specifically related to the operatorship requirements will be immaterial and are therefore assumed to be zero.

335. Where the licensee groups elect to appoint a separate well operator or installation operator to execute the functions required under the Directive, there will be additional costs associated with preparing the submissions required to support the appointments. Following each licensing round, it is estimated that approximately 10 licensee groups will elect to appoint separate well operators for

the exploration phase of operations. This estimate is based on the number of such enterprises applying for licences during recent licensing rounds. There are only a limited number of companies who will be interested in well operatorship. Following every licensing round after implementation of the Directive, it is therefore estimated that there will be a maximum of two appointees required to prepare new submissions to support their appointments, and that other potential appointees, i.e. existing well operators, will only have to update their submissions.

336. Each year, it is estimated that approximately 15 new installations begin operating on the UKCS, and it is assumed that approximately 10% of the controlling licensee groups will elect to appoint separate installation operators for the production phase of operations. This estimate is based on the current percentage of offshore installations that have an appointed duty holder. In the first year following implementation of the Directive, it is assumed that 10 current duty holders or proposed new installation operators will have to prepare submissions to support their appointments. However, in subsequent years, the existing installation operators will only have to update their submissions. As a prudent estimate, it is therefore assumed that, for the purpose of the IA, there will be one new submission and one updated submission during subsequent years. It is possible that the same percentage of controlling licensee groups will elect to appoint separate well operators for the production phase of operations, and the same prudent assumptions can be applied, although it is possible that there will be some overlap with the companies appointed as well operators for the exploration phase of operations. In both cases, the estimates used to develop costs therefore represent a prudent case in terms of the magnitude of the costs recovered from industry.

337. Each year, it is estimated that approximately 15 installations will cease operating on the UKCS and begin decommissioning, and it is again assumed that approximately 10% of the controlling licensee groups will elect to appoint separate installation operators and separate well operators for the decommissioning phase of operations. Although it is possible that there will be some overlap with the companies appointed as installation operators and well operators for the production phase of operations, the same prudent assumptions have been applied for the decommissioning phase of operations, and the estimates used to develop costs therefore represent a prudent case in terms of the magnitude of the costs recovered from industry.

338. The above estimates are in line with estimates of licensing activity, new installation developments and decommissioning activity that have been used for other functions detailed in the Impact Assessment. Based on those estimates, and for the purpose of the Impact Assessment, the assumed number of new and updated operatorship submissions during the 10 year appraisal period are summarised in Table 11.

Table 11: Forecast number of new and updated well operator and installation operator appointment submissions 2015 - 2024

Year	Well Operators (Exploration / Production / Decommissioning)		Installation Operators (Production / Decommissioning)	
	No. of new submissions	**No. of updated submissions**	**No. of new submissions**	**No. of updated submissions**
Year 0 (2015)	10	0	10	0
Year 1 (2016)	2	10	2	2
Year 2 (2017)	2	2	2	2
Year 3 (2018)	4	10	2	2
Year 4 (2019)	2	2	2	2
Year 5 (2020)	4	10	2	2
Year 6 (2021)	2	2	2	2
Year 7 (2022)	4	10	2	2
Year 8 (2023)	2	2	2	2
Year 9 (2024)	4	10	2	2

339. It is considered that the cost of reviewing the environmental and safety submissions that will be required to support applications for both well operatorship and installation operatorship will be broadly similar to the baseline environmental submission review costs plus the new safety submission review costs, as the differences in the submissions would be unlikely to have a significant effect on the review cost estimates.

340. It is therefore estimated that the review costs for new submissions would be equivalent to those discussed in paragraphs 329 to 330: that is, around £5.8 thousand per submission. Across the new submissions in Table 11, this gives a **ten-year present value cost to be recovered from industry** of between around £295 thousand and £360 thousand, with a **best estimate of around £328 thousand**.

341. It is also estimated that the review costs for updated submissions would be equivalent to those discussed in paragraphs 331 to 332: that is, around £2.9 thousand per submission. Across the new submissions in Table 11, this gives a **ten-year present value cost to be recovered from industry** of between around £165 thousand and £202 thousand, with a **best estimate of around £184 thousand**.

9.5.4 Operatorship (Costs to the Licensing Authority)

342. In addition to the Competent Authority costs in paragraphs 334 to 341, there will be costs to Licensing Authority relating to the administration of the operatorship process, and the amendment of IT systems to include functionality for the well operator and installation operator appointment processes and the recording of details of the appointments. As the operatorship process will be mediated via a portal, and will be based on a non-objection process in preference to a positive approval process, the additional administrative requirements are considered to be immaterial and the costs are assumed to be zero. However, the changes to the portal systems will be more significant. A high-level specification has been prepared for the proposals, and the current estimate of costs is **approximately £55 thousand.** This would be borne by the Licensing Authority and not recovered from industry. However, this estimate must be treated with

caution as accurate costing will not be possible until the final specification has been agreed.

9.5.5 Financial and technical aspects

343. The CA would be required to advise the licensing authority on the technical and financial aspects of new licensees. This would be required on an annual basis for licence changes, of which around 50 are made each year, and during new licensing rounds, which occur on average every 2 years and would require consideration of around 250 licences. DECC already give such advice so this would impose no additional cost, but HSE have estimated that the additional resources required each year on average would be as follows:

- around 16 hours of HSE Band 1 Offshore Inspector time at an FEC of £129.45 per hour
- around 32.5 hours of HSE Band 2 Offshore Inspector time at an FEC of £120.32 per hour
- around 60 hours of HSE Band 3 Offshore Inspector time at an FEC of £108.34 per hour

344. Adding a range of +/- 10%, this gives an estimated annual average cost per annum of between around £11 thousand and £14 thousand, with a best estimate of around £12.5 thousand and would be recovered from industry. This would be borne from Year 1 of the appraisal period to Year 9.

345. This gives a **ten-year present value cost to be recovered from industry** of between around £85.5 thousand and £104.5 thousand, with a **best estimate of around £95 thousand**.

9.5.6 Summary of Costs to the CA and Licensing Authority Related to changes to DECC Licensing Legislation to implement the Directive

346. Table 12 summarises the costs to be recovered from industry for assessments and costs borne by the Licensing authority related to changes to DECC legislation.

Table 12: Estimated costs for assessments related to changes to DECC licensing legislation

	Low	Best Estimate	High
Costs Recovered from Industry			
Licensing costs	£2,495	£2,773	£3,050
Operatorship	£460	£511	£562
Financial and technical aspects	£85	£95	£104
Costs borne by Government			
Updating licensing systems	£20	£20	£20
Updating IT portal for operatorship	£55	£55	£55
TOTAL	**£3,116**	**£3,454**	**£3,792**

Note: figures are ten-year present values. Totals may not sum due to rounding.

9.6 Costs to industry for complying with changes to HSE Legislation to implement the Directive

347. The costs to industry to comply with the new regulations have been estimated during two research group meetings with industry representatives in Aberdeen in March and April 2014, as discussed in Section 6. The costs estimated by each company were based on the full economic cost of time of the workers involved and expectations about how long it would take to complete the work. However, when the group met to discuss the cost estimates, it was apparent that the different companies' time costs and length of time they expected the work to take were quite variable. As such, the research group was not able to agree on a suitable duration and cost of time for each requirement; rather, they discussed their estimates and agreed a suitable total cost that reflected their expectations.

348. However, to illustrate the amount of work predicted by the group and to make it easier for the costs to be commented on during the consultation, the indicative hours spent were generated using an average full economic cost of time for a Health, Safety and Environment Manager. This has come from *Hays Oil & Gas Global Salary Survey 2013*[19] and is estimated at £71.67 per hour. This figure is broadly consistent with the costs of time given by the research group. Consultation comments on individual assumptions and costs are included below as appropriate, including any actions taken as a result.

9.6.1 Offshore Gas Storage and Recovery

349. As explained in paragraphs 71 to 74, the definition of 'offshore installation' will be amended to remove gas storage in line with the Directive and to avoid potential gold plating. At present, the only installation engaged in gas storage offshore also produces hydrocarbon gas and so will therefore be within the scope of SCR 2015.. No operations that would exclusively store gas offshore are expected in the future.

[19] http://hays.clikpages.co.uk/Oil_and_Gas_Salary_Guide_2013/.

350. As such, this change of definition is estimated to produce **no costs or cost savings to industry**.

9.6.2 Internal Waters

351. As explained in paragraph 75 to 77, to prevent gold plating when implementing the Directive, HSE cannot apply the new SCR 2015 to internal waters and therefore proposes to maintain the existing SCR 2005 for regulating internal waters. As this would maintain the existing requirements for internal waters, this is estimated to impose **no cost on industry**.

9.6.3 Internal Emergency Response Plans

352. Under the regulations, owners or operators would be required to add additional environmental information to their emergency plan under the Offshore Installations (Prevention of Fire and Explosion, Emergency Response) Regulations 1995 (PFEER). Although the research group agreed that they already supplied most of this information to the regulator, they estimated that the additional cost of time required to assemble this for the emergency plan per installation would be between around £1.4 thousand and £12 thousand, with a best estimate of around £6.6 thousand. This is the equivalent of between around 20 hours and 164 hours of a Health, Safety and Environment Manager, with a best estimate of around 92 hours. This assumption was largely supported in consultation.

353. In addition, owners or operators would be required to assemble an inventory of emergency response equipment. The research group reported that many already had the required information in separate documents but the additional work would be collating all the information and adding new items if necessary. They estimated that this would cost between around £1.5 thousand and £8.6 thousand per installation, with a best estimate of around £5 thousand. This is the equivalent of between around 21 hours and 120 hours of a Health, Safety and Environment Manager, with a best estimate of around 70 hours. This assumption was supported in consultation.

354. Owners or operators would also be required to write a description of their internal emergency response arrangements to be included in the safety case and well notification. The research group estimated that the cost of time would be between around £1.3 thousand and £15.4 thousand per submission, with a best estimate of around £8.3 thousand. This is the equivalent of between around 18 hours and 215 hours of a Health, Safety and Environment Manager, with a best estimate of around 116 hours. This assumption was supported in consultation.

355. This gives a total one-off cost of compliance per installation of between around £4.2 thousand and £36 thousand, with a best estimate of around £20 thousand. This is the equivalent of between around 59 hours and 500 hours of a Health, Safety and Environment Manager, with a best estimate of around 279 hours. The research group did note that this might provide an overestimate when scaled across the industry as companies with multiple installations may find it easier to complete the work as they did so across their fleet due to increased familiarity and economies of scale. However, the group was not able to agree a reasonable method to take account of this, so this is noted as a risk that the estimated cost across industry may be too high.

356. There would be a one-off cost of compliance for the 386 installations currently operating when they are required to become compliant by 2018, which is Year 3 of the appraisal period. For simplicity, this cost is assumed to be distributed equally across 2016, 2017 and 2018. This gives a **ten-year present value cost to industry** of between around £1.5 million and £12.4 million, with a **best estimate of around £6.9 million**.

357. In addition, there would be an ongoing cost for new installations to add additional information to internal emergency response arrangements, create inventories and descriptions. There are estimated to be around 15 new installations per annum. New installations must comply with the new regulations by 2016, so this ongoing cost would be borne from Year 1 of the appraisal period until Year 9.

358. The additional work for new installations to complete this work over and above what they would have to do under the existing requirements is not assumed to be different from the work for existing installations. This gives an annual average cost to industry of between around £63 thousand and £536 thousand, with a best estimate of around £300 thousand.

359. This gives a **ten-year present value cost to industry** of between around £483 thousand and £4.1 million, with a **best estimate of around £2.3 million**.

360. Lastly, the research group were asked whether the additional components and criteria of the internal emergency response arrangements would lead to an increase in the ongoing costs necessary to keep it up-to-date. The group felt that there would be a cost for some, but for others it would be absorbed into the existing running costs. They were not able to make a reasonable estimate of the proportion of installations that would incur any additional cost, so further evidence was sought during consultation. Feedback from consultation was that very few respondents thought that the cost of keeping the expanded internal emergency response arrangements up to date would be nil and that most agreed with the estimated cost, below. As such, this final stage IA assumes that all installations will incur a cost to keep the internal emergency response arrangements up to date.

361. The research group estimated that this would cost between £5.2 thousand and £15.4 thousand per annum, with a best estimate of around £10.3 thousand. This is the equivalent of between around 73 hours and 215 hours of a Health, Safety and Environment Manager per annum, with a best estimate of around 144 hours and is assumed to be borne each year following the initial set up costs, above.

362. This cost would be borne by installations as they moved into scope. This would include all new installations from 2016 and existing installations as they became compliant from 2016 to 2018. Then from Year 4, all installations would bear this cost. Over the appraisal period, this gives a total estimated average annual cost of between around £1.7 million and £5.0 million, with a best estimate of around £3.3 million.

363. This gives a **ten-year present value cost to industry** of between around £12.3 million and £36.5 million, with a **best estimate of around £24.4 million**.

9.6.4 Independent verification

364. Under the regulations, owners or operators would be required to expand their independent verification schemes to incorporate new criteria and to include environmental-critical elements (ECEs) in addition to the safety-critical elements (SCEs). Although there was some disagreement in the research group as to whether there would be any ECEs that are not already considered as SCEs, the research group did agree that the average cost of time per installation to include new criteria would be between around £10 thousand and £30 thousand, with a best estimate of around £20 thousand. Feedback from the consultation indicated this may be an underestimate because there would need to be some assessment of the environmental performance standards for SECE's. This had not been considered by the original research group. As a result, HSE followed up with the research group through a series of phone interviews to see what revisions to this estimate would be appropriate, based on the research group's initial work to make the assessments. This follow up indicated that, although some respondents felt that the cost as originally estimated was about right, others estimated that the costs would be higher, based on the work they had already begun to do, and that the upper end of the range might be twice that already estimated. Based on these discussions, this final stage IA estimates that the cost of time necessary to new criteria, including the assessment of environmental performance, would be between around £10 thousand and £60 thousand, with a best estimate of around £35 thousand. This is the equivalent of between around 140 hours and 837 hours of a Health, Safety and Environment Manager, with a best estimate of around 488 hours.

365. Owners or operators would also be required to provide a description of the extended scheme in the safety case. The research group estimated that the cost of time would be between around £2.3 thousand and £2.8 thousand, with a best estimate of around £2.5 thousand. This is the equivalent of between around 31 hours and 38 hours of a Health, Safety and Environment Manager, with a best estimate of around 35 hours. This assumption was largely supported in consultation.

366. Lastly, the group estimated that the independent verifier would charge between around £10 thousand and £20 thousand to establish new criteria for the ECEs, with a best estimate of around £15 thousand. Feedback during consultation was that this may be an underestimate because of the need to assess environmental performance criteria, as explained in paragraph 364. As part of the follow up interviews with the research group, some respondents reported that the upper range of the cost may be as high as £50 thousand, not only because of the environmental performance criteria, but also because of additional liability insurance costs incurred by the independent verifier. Based on these discussions, this final stage IA estimates that the additional charge by the independent verifier per installation would be between around £10 thousand and £50 thousand, with a best estimate of around £30 thousand.

367. This gives a total one-off cost of compliance per installation of between around £22.3 thousand and £113 thousand, with a best estimate of around £67.5 thousand.

368. There would be a one-off cost of compliance for the 386 installations currently operating when they are required to become compliant with the new regulations by 2018, which is Year 3 of the appraisal period. For simplicity, this cost is assumed to be distributed equally across 2016, 2017 and 2018. This gives a **ten-**

year present value cost to industry of between around £8.0 million and £40.5 million, with a **best estimate of around £24.2 million**.

369. In addition, there would be an ongoing cost for new installations to add these provisions to their verification schemes. There are estimated to be around 15 new installations per annum. New installations must comply with the new regulations by 2016, so this ongoing cost would be borne from Year 1 of the appraisal period until Year 9.

370. The additional work for new installations to complete this work over and above what they would have to do under the existing requirements is not assumed to be different from the work for existing installations. This gives an annual average cost to industry of between around £334 thousand and £1.7 million, with a best estimate of around £1.0 million.

371. This gives a **ten-year present value cost to industry** of between around £2.5 million and £12.9 million, with a **best estimate of around £7.7 million**.

372. Lastly, the research group were asked whether the additional components and criteria of the verification scheme would lead to an increase in the ongoing costs necessary to manage and keep it up-to-date. The research group estimated that this would cost between around £0.5 thousand and £2 thousand per annum for each installation, with a best estimate of around £1.3 thousand. This is the equivalent of between around 7 hours and 28 hours of a Health, Safety and Environment Manager per annum, with a best estimate of around 17 hours and is assumed to be borne each year following the initial set up costs, above. This assumption was broadly supported in consultation.

373. This cost would be borne by installations as they moved into scope. This would include all new installations from 2016 and existing installations as they became compliant from 2016 to 2018. Then from Year 4, all installations would bear this cost. Over the appraisal period, this gives a total estimated average annual cost of between around £162 thousand and £648 thousand, with a best estimate of around £405 thousand.

374. This gives a **ten-year present value cost to industry** of between around £1.2 million and £4.8 million, with a **best estimate of around £3.0 million**.

9.6.5 Corporate Major Accident Prevention Policy (CMAPP)

375. Under the regulations, owners or operators would be required to prepare a Corporate Major Accident Prevention Policy (CMAPP) that meets the criteria set out in the Directive. The research group agreed an average cost of time per installation to complete this and clear it through internal review procedures. HSE analysts have adjusted this figure to give an estimated average cost for each of the approximately 75 companies currently operating that will need to produce a CMAPP. This gives between around £51.5 thousand and £103 thousand per company, with a best estimate of around £77.2 thousand. This is the equivalent of between around 718 hours and 1,436 hours of a Health, Safety and Environment Manager, with a best estimate of around 1,077 hours. Some respondents to the consultation thought that this might be an overestimate, given the expected length of the CMAPP. However, HSE analysts consider that the emphasis placed on the internal review process explains this disparity and considers the research group estimate reasonable.

376. There would be a one-off cost of compliance for the approximately 75 operators and owners when they are required to become compliant with the new regulations by 2018, which is Year 3 of the appraisal period. For simplicity, this cost is assumed to be distributed equally across 2016, 2017 and 2018. This gives a **ten-year present value cost to industry** of between around £3.6 million and £7.2 million, with a **best estimate of around £5.4 million**.

377. As explained in paragraphs 230 to 231, each year between 1 and 2 new CMAPPs would be submitted to the CA each year from companies new to operating on the UKCS. The additional work for new companies to complete this is not assumed to be different from the work for existing companies. The annual average cost to industry is estimated at this stage to be between around £51.5 thousand and £206 thousand, with a best estimate of around £116 thousand.

378. This gives a **ten-year present value cost to industry** of between around £392 thousand and £1.6 million, with a **best estimate of around £881 thousand**.

379. Lastly, the research group were asked what the additional effort would be to keep the CMAPP up-to-date. The research group estimated that this would most likely take the form of an annual review and cost between around £1.3 thousand and £5.8 thousand per annum per installation, with a best estimate of around £3.6 thousand. This is the equivalent of between around 18 hours and 81 hours of a Health, Safety and Environment Manager per annum, with a best estimate of around 50 hours and is assumed to be borne each year following the initial set up costs, above. This assumption was supported in consultation.

380. This cost would be borne by installations as they moved into scope. This would include all new installations from 2016 and existing installations as they became compliant from 2016 to 2018. Then from Year 4, all installations would bear this cost. Over the appraisal period, this gives a total estimated average annual cost of between around £421 thousand and £1.9 million, with a best estimate of around £1.1 million.

381. This gives a **ten-year present value cost to industry** of between around £3.1 million and £13.8 million, with a **best estimate of around £8.5 million**.

9.6.6 Safety and Environmental Management System

382. As explained in section 8.3.6, under SCR 2015 owners or operators would be required to have a safety and environmental management system (SEMS). Owners or operators who have separate environmental and safety management systems would be allowed to maintain separate systems but would be required to outline how these separate systems work together as a SEMS and are integrated with the overall management system. An adequate description of the SEMS would then need to be included within the safety case.

383. The research group estimated that the cost of extending the SEMS to incorporate the new safety and environmental elements required by the Directive would be between around £2.8 thousand and £9 thousand, with a best estimate of around £5.9 thousand. This is the equivalent of between around 39 hours and 126 hours of a Health, Safety and Environment Manager, with a best estimate of around 82 hours. Although some respondents in the consultation thought this

might be underestimated, the estimate received overall support and this analysis considers the research group's estimate to be appropriate.

384. There would be a one-off cost of compliance for the 386 installations currently operating when they are required to become compliant with the new regulations by 2018, which is Year 3 of the appraisal period. For simplicity, this cost is assumed to be distributed equally across 2016, 2017 and 2018. This gives a **ten-year present value cost to industry** of between around £1 million and £3.2 million, with a **best estimate of around £2.1 million**.

385. In addition, the research group also estimated that the cost of writing a description of this for the safety case would be between around £1.3 thousand and £5 thousand, with a best estimate of around £3.2 thousand. This is the equivalent of between around 18 hours and 70 hours of a Health, Safety and Environment Manager, with a best estimate of around 44 hours. Although some respondents in the consultation thought this might be underestimated, the estimate received overall support and this analysis considers the research group's estimate to be appropriate.

386. This would give a one-off cost of compliance for the 386 installations currently operating when they are required to become compliant with the new regulations by 2018, which is Year 3 of the appraisal period. For simplicity, this cost is assumed to be distributed equally across 2016, 2017 and 2018. This gives a **ten-year present value cost to industry** of between around £469 thousand and £1.8 million, with a **best estimate of around £1.1 million**.

387. In addition the research group and further industry discussions confirmed that although the vast majority of non-production installation owners already have an existing EMS, it is estimated that one does not. The research group estimated a £150,000 one-off cost to create an EMS element of the SEMS resulting in a cost to industry occurring in 2016 of between around £150 thousand to £300 thousand with a best estimate of around £225 thousand, depending on the size and complexity of the installation. Based on current information, this is the equivalent of between 2,093 hours and 4,186 hours of a Health, Safety and Environmental Manager with a best estimate of 3,139 hours. In response to the public consultation 54% agreed with the estimate of the time required to prepare the EMS in accordance with the Directive requirements.

388. Assuming these costs would be borne in 2016, this gives a **ten-year present value cost to industry** of between around £145 thousand and £290 thousand, with a **best estimate of around £217 thousand**.

389. Lastly, there would be an ongoing cost for new installations to expand their SEMS and produce these descriptions. There are estimated to be around 15 new installations per annum. New installations must comply with the new regulations by 2016, so this ongoing cost would be borne from Year 1 of the appraisal period until Year 9.

390. The additional work for new installations to complete this work over and above what they would have to do under the existing requirements is not assumed to be different from the work for existing installations. This gives an annual average cost to industry of between around £61.5 thousand and £210 thousand, with a best estimate of around £136 thousand.

391. This gives a **ten-year present value cost to industry** of between around £468 thousand and £1.6 million, with a **best estimate of around £1.0 million**.

9.6.7 Safety Case

392. Under the regulations, safety cases would be required to contain additional information as outlined in the Directive. This is in addition to the CMAPP and descriptions of the verification scheme, SEMS and IERP, the costs of which have already been calculated, above.

393. The research group estimated that the cost of doing this could be substantial, including the time required for internal review and approval of the document. They estimated that this would cost between around £15 thousand and £45 thousand for a production installation safety case, with a best estimate of around £30 thousand. This is the equivalent of between around 209 hours and 628 hours of a Health, Safety and Environment Manager, with a best estimate of around 419 hours. This assumption was supported overall in consultation.

394. The research group estimated that the cost for a non-production installation safety case would be between around £5 thousand and £15 thousand, with a best estimate of around £10 thousand. This is the equivalent of between around 70 hours and 209 hours of a Health, Safety and Environment Manager, with a best estimate of around 140 hours. While some respondents to the consultation thought that this might be an underestimate, many respondents agreed with the estimate and overall the consultation did not present a case to revise the research group's estimate.

395. There would be a one-off cost of compliance for the 386 installations currently operating when they are required to become compliant with the new regulations by 2018, which is Year 3 of the appraisal period. For simplicity, this cost is assumed to be distributed equally across 2016, 2017 and 2018. Based on the current make-up of the sector, it is estimated that 66% of installations would be production installations and the remainder non-production. This gives a **ten-year present value cost to industry** of between around £4.2 million and £12.5 million, with a **best estimate of around £8.4 million**.

396. In addition, there would be an ongoing cost for new installations to produce and add information to their safety cases. There are estimated to be around 15 new installations per annum, of which 4 are expected to be production installation and 11 non-production, based on the last three year's data. New installations must comply with the new regulations by 2016, so this ongoing cost would be borne from Year 1 of the appraisal period until Year 9.

397. The additional work for new installations to add this to their safety cases over and above what they would have to do under the existing requirements is not assumed to be different from the work for existing installations. This gives an annual average cost to industry of between around £115 thousand and £345 thousand, with a best estimate of around £230 thousand.

398. This gives a **ten-year present value cost to industry** of between around £874 thousand and £2.6 million, with a **best estimate of around £1.7 million**.

399. Lastly, the research group were asked what the additional effort would be to keep the safety case up to date in light of the additional information it would

contain. The research group discussed that this would be an addition to the ongoing review processes already in place and cost between around £2 thousand and £3 thousand per annum for each installation, with a best estimate of around £2.5 thousand. This is the equivalent of between around 28 hours and 42 hours of a Health, Safety and Environment Manager per annum, with a best estimate of around 35 hours and is assumed to be borne each year following the initial set up costs, above. While some respondents thought this might be an underestimate, many others agreed with it and overall the consultation did not present a case to revise the research group's estimate.

400. This cost would be borne by installations as they moved into scope. This would include all new installations from 2016 and existing installations as they became compliant from 2016 to 2018. Then from Year 4, all installations would bear this cost. Over the appraisal period, this gives a total estimated average annual cost of between around £648 thousand and £972 thousand, with a best estimate of around £810 thousand.

401. This gives a **ten-year present value cost to industry** of between around £4.8 million and £7.1 million, with a **best estimate of around £6.0 million**.

9.6.8 Design and Relocation Notifications

402. Under the regulations, additional environmental information would be required to be added to design notifications and to relocation notifications. This is in addition to the descriptions of the verification scheme and SEMS, which have been costed above.

403. The research group estimated that the cost of time required to add the additional information to a design notification would be between around £2 thousand and £3 thousand, with a best estimate of around £2.5 thousand. This is the equivalent of between around 28 hours and 42 hours of a Health, Safety and Environment Manager, with a best estimate of around 35 hours. This assumption was broadly supported in consultation.

404. For a relocation notification, the group estimated that the cost of adding information would be minimal as most of it was already present, and so agreed that this cost would be nil. This was strongly supported in consultation.

405. Each year, around 6 design notifications are submitted, based on the last three years' data. This gives an estimated annual cost to industry of between around £12 thousand and £18 thousand, with a best estimate of around £15 thousand. This cost would be borne from Year 1 of the appraisal period to Year 9.

406. This gives a **ten-year present value cost to industry** of between around £91 thousand and £137 thousand, with a **best estimate of around £114 thousand**.

9.6.9 Well Notifications

407. Under the new regulations, additional environmental information would be required to be added to well notifications and it would be made a requirement to have the independent competent person (ICP, or well examiner) to consider the notification or any material change to a well notification prior to submission.

408. The research group estimated that the cost of time required to add the additional information to a well notification would be between around £2 thousand and £3 thousand, with a best estimate of around £2.5 thousand. This is the equivalent of between around 28 hours and 42 hours of a Health, Safety and Environment Manager, with a best estimate of around 35 hours. This estimate was overwhelmingly supported by industry in consultation.

409. Each year, around 550 well notifications are submitted, based on the last three years' data. This gives an estimated annual cost to industry of between around £1.1 million and £1.7 million, with a best estimate of around £1.4 million. This cost would be borne from Year 1 of the appraisal period to Year 9.

410. This gives a **ten-year present value cost to industry** of between around £8.4 million and £12.6 million, with a **best estimate of around £10.5 million**.

411. The research group were not able to make an estimate of the costs of having the ICP consider relevant aspects of the well notifications and material changes to well notifications prior to submission. Generally, the members of the research group did involve the ICP in preparing the notification or material change and got him or her to consider the supporting documentation and technical information that went into them. However, they did not always get the ICP to consider the actual notification itself.

412. To address this gap in the analysis, questions were asked in the consultation to elicit responses from the wider industry. On the question of what the ICP would charge to consider relevant aspects of a well notification, around a third of respondents who gave an estimate thought that the cost would be nil or that such arrangements were already in place. The remainder gave estimates ranging between around £0.5 thousand and £20 thousand. The average cost, including the zero estimates, is between around £2.7 thousand and £3.3 thousand, with a best estimate of around £3 thousand.

413. The well notifier would then need to write the ICP's findings into the well notification. As part of consultation questions, this was estimated based on responses from industry to take between around 13.5 hours and 16.5 hours, with a best estimate of around 15 hours. Consultation responses also indicated that this work would be carried out by a drilling or well engineer at an FEC per hour of £68.27.[20] This would give an average cost of between around £0.9 thousand and £1.1 thousand, with a best estimate of around £1 thousand.

414. Across the 550 well notifications submitted each year, this gives an estimated annual average cost to business of between around £2.0 million and £2.4 million, with a best estimate of around £2.2 million.

415. This gives a **ten-year present value cost to industry** of between around £15.2 million and £18.5 million, with a **best estimate of around £16.8 million**.

416. On the question of what the ICP would charge to consider a material change to the relevant aspects of a well notification, again around a third of respondents who gave an estimate thought that the cost would be nil or that such

[20] Based on the salary of a senior drilling engineer as sourced from Hays Oil & Gas Global Salary Guide (http://www.hays.com.au/cs/groups/hays_common/@au/@content/documents/digitalasset/hays_089071.pdf), uprated by 30% to account for non-wage costs.

arrangements were already in place. The remainder gave estimates that ranged between around £0.5 thousand and £10 thousand. The average cost, including the zero estimates, is between around £1.8 thousand and £2.2 thousand, with a best estimate of around £2 thousand.

417. In addition, the notifier would need to add the ICP's findings to the material change at a cost of between around £0.9 thousand and £1.1 thousand, with a best estimate of around £1 thousand, as described in paragraph 413.

418. Over the last three years, the average annual number of material changes to well notifications has been about 225. This gives an estimated average annual cost to business of between around £612 thousand and £748 thousand, with a best estimate of around £680 thousand.

419. This gives a **ten-year present value cost to industry** of between around £4.7 million and £5.7 million, with a **best estimate of around £5.2 million**.

9.6.10 Combined Operations Notifications

420. Under the regulations, additional environmental information would be required to be added to combined operations notifications. The research group estimated that most combined operations would not need any additional work to achieve compliance, but that perhaps 20% or so would. For those requiring additional information, the cost of time required to complete this would be between around £4.5 thousand and £5.5 thousand, with a best estimate of around £5 thousand. This is the equivalent of between around 63 hours and 77 hours of a Health, Safety and Environment Manager, with a best estimate of around 70 hours. This assumption was supported in consultation.

421. Each year, around 61 combined operations notifications are submitted, based on the last three years' data. This gives an estimated annual cost to industry of between around £55 thousand and £67 thousand, with a best estimate of around £61 thousand. This cost would be borne from Year 1 of the appraisal period to Year 9.

422. This gives a **ten-year present value cost to industry** of between around £418 thousand and £510 thousand, with a **best estimate of around £464 thousand**.

9.6.11 Dismantling of a fixed production installation

423. Under the regulations, additional safety and environmental information would be required to be added to safety cases for installations being dismantled, but the research group estimated that the cost of adding this additional information would be negligible as much of it is already included. This was supported in consultation.

9.6.12 Reporting imminent danger or increased risk of a major accident

424. Under the regulations, owners or operators would be required to report to the CA on instances of imminent danger or increased risk of a major accident or when a major accident had actually taken place. The research group reported that making such a report on the rare instances that it might be required were

negligible and agreed that this would impose **no cost on industry**. Although this was supported by around half of respondents in consultation, the other half were unsure what the impact would be and called for clearer guidance on what would count as reportable and what action would be required. HSE will address this as part of its developing guidance. Based on the level of detail on this topic discussed with the research group and the degree of support in consultation, HSE considers that the research group's estimate remains reasonable.

9.6.13 Reporting major accidents outside the EU

425. Under the regulations, UK-registered companies would be required to report to the CA on major accidents outside the EU. The research group reported that such events were very rare and that the effort required to make such a report were it necessary to do so would be negligible as the information would be readily to hand and already prepared for internal purposes.

426. In response to the consultation, the majority of industry respondents called for greater clarity on what types of event and what details would be reportable. As such, most respondents felt unable to comment as to the validity of the costs. To validate this estimate, HSE undertook further work including an explanatory paper and inviting correspondence from members of a key industry association and the wider industry; and through follow-up interviews with the research group. This showed that:

- there are very few UK-registered companies that operate outside of the EU as the majority will incorporate overseas operations as separate companies
- the information required to be reported would be readily to hand as a result of internal investigations, which would take place anyway
- major accidents are rare, even outside of the EU

427. As a result of these discussions, HSE remains confident in the original assessment of the research group that this would impose **no additional costs on industry**.

9.6.14 Safety Zones

428. Under the regulations, vessels would be able to request permission of the installation owner or operator to enter the installation's safety zone if necessary, whereas presently they may only request permission of the regulator. HSE analysts considered that this might yield a saving to business if there were any instances in which this might be applicable. However, the research group agreed that they could not envisage any such circumstances and agreed that this would have **nil impact on industry**. This assumption was strongly supported in consultation.

9.6.15 Collecting and Recording Data

429. Under the regulations, installations would be required to have in place technical measures to collect and record data. The research group reported that these were already in place and that this would impose **no costs on industry**. This assumption was supported in consultation.

9.6.16 Enter and Leave Notifications

430. Under the Directive, notifications of entry into or departure from the UKCS would be required to be made slightly earlier than under the present regime. The research group reported that they are already compliant with the new standard and so this would impose **no costs on industry**.

9.6.17 Promoting Change to Staff

431. During the first research group with industry, the group reported that it would take considerable effort to publicise the changes to the regulations to their staff and to embed them into their procedures and practices. They described this as 'promoting change to staff' and it can be thought of as the process through which the offshore industry will familiarise with the changes.

432. The activities that the research group described included making visits to installations, preparing and distributing promotional material, holding workshops and town hall-style meetings, updating websites and training. Several respondents said that they already had ongoing training programmes in place to maintain awareness of the existing regulations and that these additional activities would constitute a temporary expansion of this process.

433. The research group agreed that the cost of this would be between around £20 thousand and £50 thousand per installation, with a best estimate of around £35 thousand. This is the equivalent of between around 279 hours and 698 hours of a Health, Safety and Environment Manager, with a best estimate of around 488 hours. This estimate was generally supported in consultation.

434. There would be a one-off cost of compliance for the 386 installations currently operating when they are required to become compliant with the new regulations by 2018, which is Year 3 of the appraisal period. For simplicity, this cost is assumed to be distributed equally across 2016, 2017 and 2018. This gives a **ten-year present value cost to industry** of between around £7.2 million and £18 million, with a **best estimate of around £12.6 million**.

9.6.18 Implementing Act on data reporting criteria and format

435. The Implementing Act was not available at the time of preparing the consultation stage IA and from engagement with industry, HSE anticipated that the requirement to report under the Implementing Act would impose no additional costs as such reports would be routine and incorporated into existing processes for internal reporting, investigation and learning mechanisms. However, following publication of the Implementing Act on 20 October 2014, some new requirements were identified and HSE reconsidered the original assumptions. An information paper, including the new reporting template was circulated to members of the research group and was then followed up by telephone interviews to gather the necessary information to further estimate what efforts would be required to undertake reporting on top of what is currently reportable as 'dangerous occurrences' under the Reporting of Injuries, Diseases and Dangerous Occurrences Regulations (RIDDOR).

436. Based on the length of the report and the amount of information required, interviewees estimated that the time to fill in the report would range between

around 1 and 2 hours, although some reported that the additional time would be negligible. Based on the estimated FEC of around £71.67 (see paragraph 348), this gives an estimated cost per report of between around £72 and £143, with a best estimate of around £108.

437. HSE have estimated that the number of reports required each year would be similar to the number of dangerous occurrences reports currently received on average, which is around between around 144 and 176 per annum, with a best estimate of around 160 per annum. Although there is one reporting category in the Implementing Act that goes beyond those already in RIDDOR (that for a lost SECE), interviewees in the research group follow up agreed that these events would be rare and would be included within the average of around 160 reports per annum.

438. This gives a total estimated average annual cost to industry of between around £10.3 thousand and £25.2 thousand, with a best estimate of around £17.2 thousand.

439. Expected to be borne from the first year of the appraisal period, this gives an **estimated present value cost to industry** of between around £88.8 thousand and £217 thousand, with a **best estimate of around £148 thousand**.

440. In addition, some companies would need to update or expand IT systems to make and/or store reports. In the consultation stage IA, this was estimated to cost about the same as the cost to HSE of creating a new database to receive and handle incoming reports, at a cost of around £113 thousand as described in paragraph 201. This was acknowledged to be a very rough estimate in the consultation stage IA. Responses in consultation indicated that this might be an overestimate and so HSE discussed this further with the research group through the follow-up interviews.

441. These interviews indicated that companies would fall broadly into two camps: those that already had IT systems for reporting, which would only require adjustment to be compatible with the new reporting criteria; and those that managed without an IT reporting system currently and which would probably not seek to create one just for reporting under the Implementing Act. Interviewees reported that, as such, neither group would be put to great expense to accommodate the new reports and that the costs would range between nil and around £6 thousand, with a best estimate of around £3 thousand.

442. The consultation stage IA also mis-estimated the number of companies that might need to update IT systems as 30; it should have been around 75, which is the number of companies operating installations in the UKCS. This gives an **estimated one-off cost to industry** of between around nil and £450 thousand, with a **best estimate of around £225 thousand**.

9.6.19 Preparing and revising standards and good practice

443. Implementing the Directive, SCR 2015 will include an obligation encouraging operators and owners to co-operate in the production of standards and guidance. As they would not be expected to do anything more than presently, this is estimated to impose **no additional costs on industry**.

9.6.20 Transport of Inspectors Offshore

444. The Directive contains slightly wider duties on installations to provide transport and accommodation to inspectors than the current regulations. However, this is minor and is estimated to impose **no additional costs on industry**. This assessment was overwhelmingly supported in consultation.

9.6.21 Summary of costs to industry from changes to HSE legislation to implement the Directive

445. Table 13 summarises the direct costs to industry from changes to HSE legislation under Option 2.

Table 13: Summary of costs to industry from changes to HSE legislation (£thousands)

	Low	Best Estimate	High
Internal Emergency Response Plans	£14,265	£33,600	£52,935
Independent Verification	£11,751	£34,923	£58,095
Corporate Major Accident Prevention Policy	£7,093	£14,745	£22,593
Safety and Environmental Management Systems	£2,091	£4,512	£6,934
Safety Case	£9,822	£16,071	£22,320
Design and Relocation Notifications	£91	£114	£137
Well Notifications	£28,181	£32,474	£36,768
Combined Operations Notifications	£418	£464	£510
Promoting change to staff	£7,210	£12,617	£18,024
Reporting Act	£89	£373	£667
Dismantling a fixed installation	Nil	Nil	Nil
Reporting imminent danger or increased risk of a major accident	Nil	Nil	Nil
Reporting major accidents outside the EU	Nil	Nil	Nil
Safety Zones	Nil	Nil	Nil
Collecting and recording data	Nil	Nil	Nil
Enter and Leave notifications	Nil	Nil	Nil
Offshore gas storage and recovery	Nil	Nil	Nil
Internal waters	Nil	Nil	Nil
Total	**£81,010**	**£149,894**	**£218,983**

Note: figures are ten-year present values. Totals may not sum due to rounding.

9.7 Costs of Maintaining Existing Standards and Gold Plating of HSE Legislation

9.7.1 Definition of major accident

446. HSE proposes to retain the current definition of major accident as used in SCR 2005, which goes beyond that in the Directive, in order to keep within scope

diving operations of fewer than five people. As this maintains the current standard, it will impose **no additional cost on industry or the regulator**.

447. To illustrate the implications of keeping these operations within scope, HSE have attempted to estimate the costs to industry and the regulator of keeping these operations in scope to aid decision-making on this issue. However, these costs have been found to be very small, not least because diving operations of fewer than five people are rare.

448. The standards necessary to control diving risks are established in the Health and Safety at Work etc. Act 1974 and the Diving at Work Regulations 1997, which must be complied with irrespective of major hazard regulations. Therefore there would be no operational savings of removing these operations from scope.

449. It is only in the drafting of an installation's safety case that these diving operations may impose a cost, as consideration of their risks and how they will be managed must be recorded. However, the control measures on diving in the safety case would be quite generic and the content that deals with operations of less than five people specifically is estimated to be of minimal effort to produce and then keep up to date.

450. Therefore, we estimate that the costs of keeping diving operations of less than five people in scope of the major hazard regulations are minimal. However, they do ensure that the high risks of such operations are fully considered in the safety management of the installation.

9.7.2 Supplementary units connected to an offshore installation

451. HSE proposes to retain the current standard whereby supplementary units connected to offshore installations are considered as part of the installation itself for the purposes of the SCR 2015 regulations.

452. This is in keeping with the Directive for supplementary units within 500 meters of the installation (i.e. within the safety zone). However for those beyond 500 metres, this definition goes beyond the Directive and constitutes gold plating.

453. There are currently no supplementary units beyond 500 metres of an installation on the UKCS, but HSE considers that the potential of such units (for example, back-up energy generators) to contribute to a major accident means that it is proportionate to retain them within the scope of the Regulations.

454. As there are presently no such units, nor are there expected to be in the foreseeable future, this will impose **no additional costs on industry or the regulator**.

9.7.3 Enter or leave notifications for non-production installations

455. HSE proposes to retain the current standard whereby both production and non-production installations are required to notify the regulator of their entry into or departure from UK territorial waters. The Directive only requires production installations to do this, but HSE believes that removing non-production

installations from scope of this requirement would have a detrimental impact on safety standards in that it would not allow HSE to maintain safety standards and minimise the possibility of major accidents on NPIs, such as the Deepwater Horizon disaster in the Gulf of Mexico. As this maintains the current standard, it will impose **no additional cost on industry or the regulator**.

456. However, to illustrate the implications of keeping these installations within scope, indicative costs have been estimated to aid decision-making on this issue. It is estimated based on observed data that each year on average there are around 16 entry or leave notifications and that 14 are made by non-production installations. The Offshore Baseline Assessment estimated that the cost to industry of preparing and submitting such a notification is between around £350 and £860 in 2012 prices, with a best estimate of around £550. This gives an annual average cost to industry of between around £4.9 thousand and £12 thousand, with a best estimate of around £7.7 thousand. This would be borne from Year 0 of the appraisal period to Year 9 and would constitute a saving if this requirement were removed.

457. This gives an estimated present value over ten years of between around £42.3 thousand and £104 thousand, with a best estimate of around £66.8 thousand. However, as industry is already compliant with this measure, this is a baseline cost and no additional cost is imposed on industry.

9.8 Costs to industry for complying with changes to DECC Environmental Legislation to implement the Directive

9.8.1 Amendments to the OPRC Regulations

458. Workloads relating to changes to the OPRC Regulations to meet the Directive requirements for the 10 year assessment period are summarised below:

- New OPEPs for new Production Installation decommissioning operations from 2015 to 2024.
- Review OPEPs for existing Production Installations by 2018.
- Reviewing existing OPEPs for Production Installations earlier than expected from 2016 to 2023
- New OPEPs for new Production Installations from 2015 to 2024.
- Review of new OPEPs for Production Installations five years after initial preparation during the period from 2015 to 2024 (one review for each OPEP).
- New OPEPs for existing Non-Production Installations, including MODUs / Intervention Vessels, from 2015 to 2016
- New OPEPs for new Non-Production Installations, including MODUs / Intervention Vessels, from 2015 to 2024
- Review of new OPEPs for Non-Production Installations five years after initial preparation during the period 2015 to 2024 (one review for each OPEP)
- New OPEP Addenda for well operations from 2015 to 2024.
- New OPEP Addenda for combined well operations from 2015 to 2024.

459. The requirements and associated costs relating to specific Directive obligations are outlined below.

9.8.1.1 Extend the OPEP requirements (as part of the Directive obligation to produce an IERP) to include the decommissioning of offshore installations

460. As explained in Section 9.4.1.1, each year, operators of installations scheduled for decommissioning would have to prepare and submit 15 OPEPs to DECC for review and approval, and so there would be 150 OPEPs submitted during the period 2015 to 2024.

461. Industry estimated at the research group that the cost of preparing and submitting one decommissioning OPEP would be between £10,000 and £15,000 with best estimate of around £12,500. This is the equivalent of between around 140 hours and 209 hours of a Health, Safety and Environmental Manager with a best estimate of around 174 hours. In response to the public consultation, 61% agreed with the estimate of time taken to prepare and submit a decommissioning OPEP.

462. This gives a **ten year present value cost to industry** of between £1.3 million and £1.9 million with a **best estimate of £1.6 million**.

9.8.1.2 Amend the OPEP requirements for Production Installations (as part of the Directive's obligations to produce an IERP)

463. **Existing OPEPs for Production Installations:** As explained in paragraphs 280 to 282, operators would have to revise and submit a total of 92 existing Production Installation OPEPs for review / re-approval between 2016 and 2018. For simplicity, these are assumed to be spread evenly over the three years.

464. Industry estimated at the research group the cost of adding the additional Directive requirements e.g. the assessment of oil response effectiveness and inventories of oil spill response equipment as costing around £10,000 per OPEP.

465. This is equivalent to between around 126 to 153 hours (calculated by deploying a low (-10%) / best estimate (medium) / high (+10%) approach) of a Health, Safety and Environmental Manager with a best estimate of 140 hours. In response to the public consultation 70% agreed with the estimate of the time required to add the additional Directive requirements to both existing and new OPEPs for production installations.

466. The **NPV of the total costs to industry** for preparing and submitting existing Production Installation OPEPs by 2018 (calculated by deploying a low (-10%) / best estimate (medium) / high (+10%) approach) are between £773 thousand and £945 thousand with a **best estimate of £859 thousand**.

467. **'Bringing forward' reviews of existing OPEPs for Production Installations:** As part of the alignment of the OPEP and safety case review cycle, explained in paragraph 285, the OPEP review cycle will need to be brought in line with the safety case review cycle.

468. This means that the new elements of the OPEP will need to be reviewed and this will represent a wholly new cost (as described in paragraphs 463 466. However, the rest of the OPEP would need to be reviewed at some point anyway, but alignment of the review cycle with that of the safety case means that in some cases it will need to be reviewed earlier than it otherwise would have been under the baseline.[21] Due to the effect of discounting, in net present value terms this leads to additional costs as the closer to the present, the greater we value a given cost or benefit.[22]

469. Based on DECC's analysis of OPEP review cycles, it is estimated that around 45 existing OPEPs would have their reviews brought forward in this manner and that the average 'brought forward' period would be just over two years. This means that around 45 existing OPEPs will now be reviewed in the period 2016 to 2018, when they otherwise would have been reviewed in the period 2018 to 2020.

470. In addition, this will also mean that some of these 45 OPEPs will now require an additional review in this analysis's appraisal period of 2015-2024. This is because if their review schedule were not brought forward in this way, the later reviews would fall after the cut-off year, i.e. from 2025 onwards.

471. Discussion with industry at the research group gave an estimate of £25,000 to produce an entirely new production OPEP, including all requirements (not just those of the Directive). Based on DECC's experience of reviewing existing OPEPs, it is assumed that the cost to industry that can be ascribed to additional Directive requirements of submitting a production installation OPEP for 5 year review is approximately 10%, or between around £2.3 thousand and £2.8 thousand, with a best estimate of around £2.5 thousand.

472. This is equivalent to between around 31 and 38 hours of a Health, Safety and Environmental Manager, with a best estimate of around 35 hours. In response to the public consultation 69% agreed with the estimate of the time required to consider the additional Directive requirements when submitting an OPEP for a production installation for review.

473. For simplicity, the 45 OPEP reviews are assumed to be spread evenly over a three-year period.

474. Table 14 summarises the expected costs under the baseline and Option 2 for the best estimate cost.

[21] Please note that this is also a separate issue from the costs of subsequent review of the *wholly new* OPEP elements for production installations, described in paragraphs 480 to 483.
[22] This is in-line with guidelines on inter-temporal discounting in HMT's Green Book.

Table 14: Summary of change in existing OPEP review cycles for production installations

	Costs			
Year	**Baseline**	**Option 2**	***Option 2 ('brought forward' element only)***	***Option 2 (additional review only)***
2015	£0	£0	*£0*	*£0*
2016	£0	£37,500	*£37,500*	*£0*
2017	£0	£37,500	*£37,500*	*£0*
2018	£37,500	£37,500	*£37,500*	*£0*
2019	£37,500	£0	*£0*	*£0*
2020	£37,500	£0	*£0*	*£0*
2021	£0	£37,500	*£37,500*	*£0*
2022	£0	£37,500	*£37,500*	*£0*
2023	£37,500	£37,500	*£0*	*£37,500*
2024	£37,500	£0	*£0*	*£0*
Present Value	**£154,100**	**£193,500**	***£165,000***	***£28,500***
Difference from Baseline PV	**-**	**£39,500**	***£11,000***	***£28,500***

Note: totals may not sum due to rounding

475. This gives an additional **ten-year present value cost to industry** of between around £35.5 thousand and £43.4 thousand, with a **best estimate of around £39.5 thousand**. This is mostly driven by the cost of the additional reviews of a best estimate of around £28.5 thousand, rather than the cost of bringing forward all reviews of a best estimate of around £11.0 thousand.

476. **New OPEPs for new Production Installations:** Based on data collated by DECC and HSE on new developments over recent years, it is estimated that 4 new OPEPs will be required per year from 2015 to 2024 to cover new Production Installations. During the 10-year assessment period, DECC will therefore have to review and approve a total of 40 OPEPs for new Production Installations.

477. Industry estimated at the research group that the additional time costs in relation to the Directive requirements, e.g. the assessment of oil response effectiveness and inventories of oil spill response equipment, would cost around £10,000 per OPEP.

478. This is equivalent to between around 126 to 153 hours (calculated by deploying a low (-10%) / best estimate (medium) / high (+10%) approach) of a Health, Safety and Environmental Manager, with a best estimate of 140 hours.

479. The **NPV of the total costs to industry** for new Production Installation OPEPs by from 2015 to 2024 (calculated by deploying a low (-10%) / best estimate (medium) / high (+10%) approach) are between £310 thousand and £379 thousand with a **best estimate of £344 thousand**.

480. **Subsequent five-yearly reviews of Production Installation OPEPs:** As explained in paragraphs 296 to 298, for the purpose of this Impact Assessment it is assumed that there would be one full five-yearly review cycle for 91 OPEPs

during the five-year period 2020 up to 2024 and that these reviews will be spread evenly over that period.

481. Discussion with industry at the research group gave an estimate of £25,000 to produce an entirely new production OPEP, including all requirements (not just those of the Directive). Based on DECC's experience of reviewing existing OPEPs we have made an assumption that the cost to industry that can be ascribed to additional Directive requirements of submitting an OPEP for 5 year review is approximately 10%, or £2500.

482. This is equivalent to between around 31 to 38 hours (calculated by deploying a low (-10%) / best estimate (medium) / high (+10%) approach) of a Health, Safety and Environmental Manager with a best estimate of 35 hours. In response to the public consultation 69% agreed with the estimate of the time required to consider the additional Directive requirements when submitting an OPEP for a production installation for review.

483. The **NPV of the total costs to industry** for 5-yearly review of Production Installation OPEPs from 2020 to 2024 (calculated by deploying a low (-10%) / best estimate (medium) / high (+10%) approach) are between £161 thousand and £197 thousand with a **best estimate of £179 thousand**.

9.8.1.3 Extend the OPEP requirements (as part of the Directive obligation to produce an IERP) to the owners of Non-production offshore installations

484. Responsibility for the development and maintenance of an OPEP will be extended to the owners of non-production installations.

485. **New OPEPs for existing Non-production Installations:** There are currently 106 non-production installations operating in UK waters. The owners of these installations will be required to prepare OPEPs that will have to be submitted to DECC and approved within a year of the new regulations coming into force i.e. by July 2016. This will be new work directly related to implementation of the Directive.

486. Industry estimated at the research group that the cost of preparing and submitting a non-production installation OPEP to DECC would be between £10,000 and £15,000 with best estimate of around £12,500. This may be an overestimate as industry was anticipating that an OPEP for a non-production installation would be done to the same requirements as that for a production installation. However, this is not the case, as OPEPs for non-production installations will only be required to satisfy the requirements of the Directive. This is the equivalent of between around 140 hours and 209 hours of a Health, Safety and Environmental Manager with a best estimate of around 174 hours. In response to the public consultation 59% agreed with the estimate of the time required to prepare and submit an OPEP for existing and new non-production installations.

487. This gives a **ten year present value cost to industry** of between around £1.0 million and £1.6 million with a **best estimate of £1.3 million**.

488. **<u>New OPEPs for new Non-production Installations during the period 2015 to 2024</u>:** Based on data collated by DECC and HSE on new non-production installations operating in the UKCS over recent years, it is estimated that 5 new OPEPs will be required per year from 2015 to 2024 to cover new non-production Installations. However, as non-production installations move around the UKCS, this figure might be overestimated. It has not been possible to estimate how great this overestimation might be, but given the small number of new OPEPs for non-production installations, it is expected to be small From 2015 to 2024, we will assume DECC will therefore have to review and approve a total of 50 OPEPs for new non-Production Installations.

489. As explained in paragraph 486, industry estimated that the cost of preparing and submitting a non-production installation OPEP to DECC would be between £10,000 and £15,000 with best estimate of around £12,500.

490. This gives a **ten year present value cost to industry** of between around £484 thousand and £592 thousand with a **best estimate of £538 thousand.**

491. **<u>Subsequent five-yearly reviews of OPEPs for Non-production Installations</u>:** As explained in paragraph 308, 131 OPEPs for Non-production Installations would have to be reviewed on a five-yearly cycle that would have to be aligned with the safety case review cycle. At this juncture, it is assumed that it is unlikely that there would be a material change to force an early review, and that every OPEP for a Non-production Installation will be reviewed once during the period 2020 to 2024.

492. Discussion with industry gave an estimate of £10,000 to £15,000 to produce a new production OPEP from scratch including all requirements (not just those of the Directive). Based on DECC's experience of reviewing existing OPEPs we have made an assumption that the cost to industry that can be ascribed to additional Directive requirements of submitting a non-production installation OPEP for 5 year review is approximately 10%, or £1000 to £1500 with a best estimate of £1250.

493. This is the equivalent of between around 14 hours and 21 hours of a Health, Safety and Environmental Manager with a best estimate of around 17 hours. In response to the public consultation 54% agreed with the estimate of the time required to prepare and submit an OPEP for a non-production installation review. Those who disagreed either considered the cost to be under-estimated or felt that there was too much uncertainty about the requirements to agree with the estimate. Only two respondents provided alternative estimates and it was therefore considered that there was no strong case to justify an alternative estimate to that provided. However, guidance will be provided to clarify the requirements for a non-production OPEP. On this basis, HSE and DECC consider the estimate in the IA to be reasonable

494. This gives a **ten year present value cost to industry** of between around £103 thousand and £155 thousand with a **best estimate of £129 thousand**.

495. **<u>Well operations</u>:** As explained in paragraph 312, it is anticipated that 300 well operations addenda will be submitted each year from 2015 to 2024.

496. Industry estimated at the research group that the cost of preparing and submitting a well operations OPEP addendum to DECC would be between £1,440 and £10,000 with best estimate of around £5,700. This is the equivalent of

between around 20 hours and 140 hours of a Health, Safety and Environmental Manager with a best estimate of around 80 hours. In response to the public consultation 63% agreed with the estimate of the time required to prepare and submit a well operations addendum to support a well notification.

497. This gives a ten year present value cost to industry of between around £3.6 million and £25.8 million with a **best estimate of £14.7 million.**

498. **<u>Combined Operations</u>:** As explained in paragraph 315, based on combined operations addenda received by DECC in recent years, it is anticipated that 40 addenda for 'combined operations' (additional to the well operations addenda) will be submitted each year from 2015 to 2024.

499. Industry estimated at the research group that the cost of preparing and submitting a combined operations OPEP addendum to DECC would be between £5,000 and £10,000 with best estimate of around £7,500. This is the equivalent of between around 70 hours and 140 hours of a Health, Safety and Environmental Manager with a best estimate of around 105 hours. In response to the public consultation 66% agreed with the estimate of the time required to prepare and submit an OPEP addendum to support a combined operations notification.

500. This gives a ten year present value cost to industry of between around £1.7 million and £3.4 million with a **best estimate of £2.6 million.**

9.8.1.4 Preparedness for the implementation of the plan and interaction with the external emergency response plan

501. Operators and owners are required to undertake OPEP exercises and to retain evidence of the exercises undertaken both onshore and offshore and to provide that evidence on request. Exercises are a current requirement and the cost implications for industry relating to retaining the evidence of exercises are considered to be negligible as most, if not all, operators do this already. In response to the public consultation 78% agreed that there would be no additional cost to business.

9.8.1.5 Powers of Inspectors to prohibit operations where no OPEP is in place, or where the plan is deemed insufficient or the requirements of the plan are not being met

502. The current OPRC regulations require that operators submit an OPEP prior to commencing operations. In line with the requirements of the Directive, DECC proposes to require that the OPEP is approved as part of the IERP prior to the commencement of operations. DECC has never delayed or prohibited an oil and gas operation as a result of an operator not having an approved OPEP or one that does not meet the OPRC requirements, once approved. DECC does not envisage this changing as, given the requirements of the Directive and the link between the IERP and the Safety Case, it will be virtually impossible for any operator or owner to undertake operations without an approved OPEP. Therefore, DECC **does not anticipate any additional costs to industry** as this simply introduces a legal requirement to do what operators are already expected to do. In response to the public consultation, 66% agreed that the requirement to have an approved OPEP before operations commence would not

result in any additional cost to industry. In addition, 74% agreed that the power to prohibit operations will not result in any additional costs to industry.

9.8.2 Financial Liability Arrangements

503. Based on the number of development wells drilled in recent years, expanding the scope of the financial responsibility provisions to wells other than exploration and appraisal wells will result in approximately 50 additional reviews per year.

504. The industry research group estimated that the provision of evidence of financial liability would cost between £1,300 and £8,000 with a best estimate of £4,650.

505. This is the equivalent of between around 18 hours and 112 hours of a Health, Safety and Environmental Manager with a best estimate of around 65 hours. In response to the public consultation 68% agreed with the estimate of the time required to provide sufficient evidence of the financial arrangements in place.

506. This gives a **ten year present value cost to industry** of between around £559 thousand and £3.4 million with a **best estimate of £2 million**.

9.8.3 Summary of Costs to Industry for Complying with Changes to DECC Environmental Legislation to Implement the Directive

507. Table 15 summarises costs to industry from complying with changes to DECC legislation to implement the Directive under Option 2.

Table 15: Estimated costs to industry from changes to DECC legislation (£thousands)

	Low	Best Estimate	High
OPEPs			
Decommissioning OPEPs	£1,291	£1,614	£1,937
Amendments to OPEPs for Production Installations	£1,280	£1,422	£1,564
Extending OPEPs to Non-Production Installations	£1,629	£1,969	£2,310
Well Operation OPEPs	£3,615	£14,719	£25,823
Combined Operations OPEPs	£1,722	£2,582	£3,443
Prohibition Notices	Nil	Nil	Nil
OPEP Exercises	Nil	Nil	Nil
Financial Liability Arrangements	£559	£2,001	£3,443
Total	**£10,097**	**£24,308**	**£38,520**

Note: figures are ten-year present values. Totals may not sum due to rounding.

9.9 Costs to industry for complying with changes to DECC Licensing Legislation to Implement the Directive

508. Following completion of the consultation, cost estimates were developed with industry representatives relating to the multiple operator model. These were further tested with a range of operators and duty holders who broadly agreed with the estimates and did not provide any amended or alternative costs.

9.9.1 Licensing

509. The current environmental requirements relating to licensing are detailed in the Appendix C document that forms part of the licensing guidance.[23]

510. For the purpose of determining the additional licensing costs relating to implementation of the Directive, the baseline environmental costs can be ignored, as the additional requirements relating to the Directive are considered to be immaterial and it is therefore assumed that there would be zero additional cost. However, the costs relating to preparing and updating the safety submissions will be new, additional costs.

511. It is estimated that, excluding the block sensitivity assessment, it would cost between around £5.4 thousand and £6.6 thousand, with a best estimate of around £6.0 thousand for a new licensing submission. This is the equivalent of

23 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/337221/28R_Environmental_guidance.pdf

between around 75 hours and 92 hours of a Health, Safety and Environment Manager, with a best estimate of around 84 hours. The block sensitivity assessment is undertaken by contracted environmental consultants and costs between £3 thousand and £4 thousand, but there is assumed to be zero additional cost for the purpose of this IA, as the proposed changes relating to the Directive requirements will be immaterial and are therefore not expected to affect the current unit cost.

512. The new safety requirements relating to licensing have still to be confirmed, but will be broadly based on the aspects detailed in paragraph 2.20 of the Consultation Document. HSE has confirmed that it is unlikely to be prescriptive in relation to the content or format of submissions, and the requirements will probably be expressed as principles or goals to be attained. Applicants will therefore be required to provide an adequate demonstration of how those principles or goals are, or will be, achieved in practice. However, HSE considers it likely that applicants will have much of the information and raw material that will be needed already to hand, as a result of having their own management systems in place and the due diligence exercises that they conduct. Nevertheless, they accept that there will be variety in the approach that individual applicants take, and therefore a variety of costs.

513. Based on the information detailed in paragraph 2.20 of the Consultation Document, and the HSE assessment that most of the requirements will already be to hand, the operators and duty holders approached in relation to the assessment of costs have indicated that it could cost between around £13.5 thousand and £16.5 thousand, with a best estimate of around £15 thousand, to collate, check and authorise a new safety submission for a licence application. This is the equivalent of between around 188 hours and 230 hours of a Health, Safety and Environment Manager, with a best estimate of around 209 hours.

514. Based on the number of new licensing submissions in Table 10, this gives a **ten-year estimated present value cost to industry** of between around £2.8 million and £3.4 million, with a **best estimate of around £3.1 million**,

515. For updated environmental submissions, the operators and duty holders approached in relation to the assessment of costs have indicated that it could cost between around £1.1 thousand and 1.3 thousand, with a best estimate of around £1.2 thousand, to collate, check and authorise a new safety submission for a licence application. This is the equivalent of between around 15 hours and 18 hours of a Health, Safety and Environment Manager, with a best estimate of around 17 hours.

516. They also estimated that the cost of an updated safety submission would be the same again. That is, between around £1.1 thousand and £1.3 thousand, with a best estimate of around £1.2 thousand.

517. Based on the number of updated licensing submissions in Table 10, this gives a **ten-year estimated present value cost to industry** of between around £1.2 million and £1.5 million, with a **best estimate of around £1.3 million**.

9.9.2 Operatorship

518. It is considered likely that the cost of preparing the environmental and safety submissions that will be required to support applications for both well operatorship and installation operatorship will be broadly similar to the baseline environmental submission preparation costs plus the new safety submission preparation costs estimated for licence applications. Although there will be some differences between the requirements, it is considered unlikely that they would have a significant effect on the cost estimates. (The cost of block sensitivity assessments can be ignored, as these assessments will not be required to support operatorship appointment). The operators and duty holders approached in relation to the assessment of costs considered this to be a reasonable assumption.

519. It is estimated that the total preparation costs per new submission would be between around £13.5 thousand and £16.5 thousand, with a best estimate of around £15 thousand. This is the equivalent of between around 188 hours and 230 hours of a Health, Safety and Environment Manager, with a best estimate of around 209 hours.

520. Based on the number of new well and installation operators' submissions in Table 11, this gives a **ten-year estimated present value cost to industry** of between around £769 thousand and £940 thousand, with a **best estimate of around £854 thousand**,

521. It is estimated that the total preparation costs per updated submission would be between around £2.2 thousand and £2.6 thousand, with a best estimate of around £2.4 thousand. This is the equivalent of between around 30 hours and 37 hours of a Health, Safety and Environment Manager, with a best estimate of around 33 hours.

522. Based on the number of updated well and installation operators' submissions in Table 11, this gives a **ten-year estimated present value cost to industry** of between around £139 thousand and £170 thousand, with a **best estimate of around £154 thousand.**

523. In order to further test the costs that were estimated following discussions with a sample group of operators and consultants, comments on the estimated costs were requested from all existing operators who utilise duty holders and the duty holders themselves (15 companies in total) along with Oil and Gas UK. Six responses were received. Of those six, three either had no comment or were content; one indicated that, if the operators carried out the work themselves the costs were about right, but if they utilised consultants they were likely to be higher; one indicated that the new approach would effectively transfer costs from the operator to the duty holder (and the overall impact would be cost neutral); and one confirmed that they saw minimal impact as a result of the revised multiple operatorship approach. Taking these views into consideration, along with the views of the original companies who assisted in developing the costs, DECC considers that the costs detailed above are reasonable.

9.9.3 Summary of Costs to industry to comply with changes to DECC Licensing legislation to implement the Directive

524. Table 16 summarises the direct costs to industry to comply with changes to DECC licensing legislation.

Table 16: Summary of costs to industry to comply with changes to DECC Licensing legislation to implement the Directive (£thousands)

	Low	Best Estimate	High
Costs to Industry			
Licensing costs	£3,987	£4,430	£4,873
Operatorship	£908	£1,009	£1,109
NET COST	**£4,895**	**£5,438**	**£5,982**

Note: figures are ten-year present values. Totals may not sum due to rounding.

9.10 Costs for Maintaining Existing Standards of DECC Legislation

525. Oil Pollution Emergency Plans As detailed in Section 8.7.1, there is one area where DECC maintain a current standard under the Directive Implementation. In relation to operators of production installations, DECC intends to retain the current requirements for oil pollution emergency plans to ensure that existing standards are maintained and that the UK can continue to satisfy the requirements of the international conventions detailed in these sections. As this requirement is covered by international conventions, it is not classified as gold plating.[24] As industry is already adhering to these requirements, there will be no additional costs imposed on the industry.

9.11 Costs to industry for complying with legislation to implement Article 38

526. As described in Section 8.8 the Directive extends the scope of the Environmental Liability Directive (ELD). The ELD only requires action where a business or other operator has caused – or is imminently about to cause – environmental damage. ELD already covered cases of damage in the marine environment that had a significant adverse effect on the status of waters under the Water Framework Directive or on reaching or maintaining favourable conservation status under the Habitats and Wild Birds Directives. From 19 July 2015, Article 38 will expand the definition to include significant adverse effects on the environmental status of marine waters under the Marine Strategy Framework Directive (MSFD).

527. This Impact Assessment (IA) considers the additional impacts of this extension of liability. In principle these could include additional:

- costs of remediation to the extent that the change introduces new liability;

[24] In accordance with the Better Regulation Framework Manual 1.9.8.iii

- costs to assess whether or not damage has occurred and what action to take;
- costs to prevent damage occurring where damage is considered imminent;
- costs of anticipatory action taken to reduce the risk of future liability, or financial security to transfer that risk;
- additional costs of familiarisation with change in policy; and
- benefits from additional remediation and reduced damage.

528. These impacts mainly depend either on the extent to which Article 38 introduces new liabilities; or businesses or other parties perceive potential increased liability.

529. Defra asked questions as part of its consultation on transposing Article 38 of the Offshore Safety Directive about the potential for this change triggering liability and the associated costs. Defra also convened a workshop of the best placed regulator and business representatives to explore the impacts in more detail [and cross-checked the following assessment with them].

9.11.1 Assessment of additional liability

530. Evidence both from the original IA[25] of the ELD and from experience of ELD so far show that cases of damage with the potential to trigger the existing definitions of environmental damage (which refer to the Water Framework Directive and Habitats Directive and Wild Birds Directive) are extremely rare. The original IA was done before the thresholds for damage were fully understood and so was cautious in estimating that, at maximum, there could be up to one case of damage falling under ELD in the UK marine environment every two years. In practice, not a single case of environmental damage has so far triggered ELD in marine waters across the entire European Union in the period since it was first introduced (2007-2014). Reasons for this in the UK include:

- the scale of damage required to trigger the definition;
- the rigour of ex-ante regulation;
- the fact that damage to species and habitats excludes negative variations that are smaller than natural variations. This further restricts the scope as natural variations can be wide given the dynamic nature of the marine environment;
- that liability needs to be assigned to one or more operators who are specifically responsible for the damage in question – ruling out diffuse or accumulated damage;
- challenges in monitoring, detecting and enforcing damage in the marine environment; and
- reduced levels of economic activity in the marine environment compared to on land

[25] http://www.legislation.gov.uk/uksi/2009/153/impacts

531. The new definition would be wider than the Water Framework Directive definition (which applies to one nautical mile or three nautical miles in Scotland) and the Habitats and Birds Directive definition, because of the breadth of the MSFD descriptors[26]. Therefore there could either be cases of damage brought into the ELD by Article 38 or cases of damage already covered by ELD for which Article 38 would increase the liability by extending the range of features to which liability would apply.

532. There is no comprehensive time series data of damage in the marine environment. Defra therefore held a workshop with a dozen of the best-placed regulator and business representatives to review the potential for additional liability. The conclusions, based on current understanding of definitions, were that:

- **It is extremely unlikely that any cases will be caught by the MSFD definition**. Neither business representatives nor regulators could think of any case in the past 50 years that would have triggered the definition at all. No Environmental Impact Assessment (EIA) (which are generally required for developments and are based on past experience) was known to have envisaged damage on the required scale. The current rigour of ex-ante regulation in the UK marine environment makes damage occurring in the future less likely than in the past.

- **It is even less likely that a case would be caught by MSFD that would not already be caught by the existing ELD definition**. The only possible scenarios that stakeholders could imagine causing damage in the future were damage to cetaceans (whales, dolphins, porpoises) caused by an oil spill from a ship or damage from exploration wells in an unknown area. If these did arise, stakeholders considered these would already have been picked up under the existing definition so would not be additional.

533. In summary, while it is not possible to accurately model the potential additional liability, stakeholder views suggest it is likely to arise somewhere in the spectrum from "never" to a maximum of "once every 50 years" – i.e. an average of between 0 and 0.02 incidents per year.

9.11.2 Costs and benefits of additional remediation

534. If and where such damage does arise, there are likely to be costs under existing arrangements to address the damage, depending on the nature of damage caused. Analysis undertaken for the original ELD IA suggested that opportunities to restore damage directly will be limited in the marine environment and that the measures required will therefore largely be to compensate for the damage. There may be limited opportunities to take such measures in the marine environment so these may sometimes be taken on land. The compensatory measures for one case of water damage on land are estimated to have cost less

[26] The 11 MSFD descriptors are: biological diversity; non-indigenous species; commercially exploited fish and shellfish; food webs; human-induced eutrophication; sea floor; hydrographical conditions; contaminants; contaminants in fish and other seafood; marine litter; and the introduction of energy (including underwater noise)

than £200 thousand (from the damage assessment for the case). The costs of cases across the EU range from £2 thousand to £2.1 million (for all types of cases, not just water damage) although this is likely to include some costs that would have been incurred irrespective of the ELD. On the basis of this information it is assumed likely that the costs of this extension (over and above any costs that would be incurred under existing liability) are unlikely, on average, to exceed £2.1 million.

535. The original IA showed that it will normally be possible to find opportunities to implement compensatory measures for which the benefits outweigh the costs; and that maximising benefits is built into the decision criteria required under the ELD.

536. Based on the estimate in paragraph 533 that the likelihood of compensation arising in any one year is between nil and 0.02 and based on the maximum compensation of £2.1 million, this gives an estimated average annual cost to business of between around nil and £42 thousand, with a best estimate of around £21 thousand.

537. This gives a **ten-year present value cost to industry** of between around nil and £362 thousand, with a **best estimate of around £181 thousand**. However, as this cost will be incurred to mitigate environmental damage, this will be cost-neutral to society overall.

9.11.3 Additional assessment costs

538. The three potential types of assessment cost are:

- **Ex-ante assessment to help manage risks of causing damage.** Stakeholders were confident that no additional ex-ante assessment would be undertaken because: 1) all feasible assessment is already done under existing regulation; and 2) the marine environment is too dynamic a system for meaningful baseline assessments in the context of ELD.

- **Assessment to confirm whether the threshold has been breached**. Stakeholders provided the view that in the event of a borderline case, considering the MSFD descriptors could take some additional time compared with just considering the existing ELD threshold. However, they did not think that additional data would be sought compared to what would currently be collected in the event of a case of damage.

- **Assessment in the event of confirmed cases of damage to determine what measures to take**. This is included in the costs of damage reported above.

9.11.4 Additional costs and benefits of action to prevent an imminent threat

539. Industry views suggested that: 1) existing regulation and management practices mean that any business operating in the marine environment would already take all possible action in response to identifying an imminent threat so this would not make a difference; and 2) it would not in any case be possible to

distinguish between an imminent threat of causing existing ELD liability and that introduced by this change.

9.11.5 Additional costs and benefits of taking anticipatory action to reduce the risk of future liability

540. Similarly, industry views suggested that they would not take any anticipatory action to reduce the risk of future liability given that they already take all feasible actions under existing arrangements.

9.11.6 Additional costs of transferring liability through financial security

541. The oil and gas industry representative reported that the insurance market is not yet willing to cover any additional risks arising from the extension given that they do not yet have a track record of the change to confidently assess the risks.

542. The representative reported that this is creating business uncertainty because regulators require that applicants for licences must demonstrate that they have any liabilities covered. In the past this has not been required for potential liabilities under the Habitats Directive and ELD when originally introduced; but the position has not yet been clarified either through communications or through experience.

9.11.7 Additional costs of familiarisation with change in policy

543. Discussions suggested that even though no additional action is feasible or required by the policy change, in practice industry trade associations spent time interpreting and understanding the policy change, and discussing with relevant government bodies, to be able to communicate this simply to their members. The oil and gas representative estimated that their trade association will have taken the equivalent of half a person year. Other trade associations (of which there are fewer than 10 main ones) estimated that they will have taken between a few days and two months. In total this might add up to another half year of staff time. The familiarisation time is therefore estimated to be in the region of one full time equivalent year.

544. Based on the FEC of a production manager and director[27], this gives a **one-off cost to industry of around £66 thousand**.

9.12 Costs to industry for complying with changes to update additional HSE legislation

9.12.1 Updating the definition of offshore installation in MAR

545. As discussed in paragraphs 170 to 172, the proposed changes would bring clarity and consistency across offshore regulations and make sure health and safety standards are maintained when high-risk decommissioning and

[27] ASHE 2013(p), SOC Code 112: Production managers and Directors, uprated by 30% to account for on-wage costs and overheads.

dismantling activities occur. There are no procedural changes and so **no additional costs to industry or the regulator**.

9.12.2 Underground Coal Gasification (UCG)

546. HSE is aware of only two onshore UCG projects expected to begin within the next ten years and no offshore ones. The onshore projects are expected to start up in the next 3 to 5 years. The costs associated with bringing them into scope have been estimated as part of the Onshore Baseline Assessment project, which produced an estimate of the annual cost for an onshore operator to be within scope of BSOR and DCR. This was estimated to be around £38.2 thousand per annum in 2012 prices. Adding a range of +/- 10% gives between around £34.4 thousand and £42.1 thousand.

547. Assuming that both operations will start up in four years' time, this gives a total cost to industry of between around £69 thousand and £84 thousand, with a best estimate of around £76 thousand to be borne from Year 4 to Year 9 of the appraisal period. This estimate was supported in consultation.

548. This gives a **present value over ten years** of between around £331 thousand and £404 thousand, with a **best estimate of around £368 thousand**. However, this will not be in scope of One In, Two Out (OITO), since it is covered by Directive 92/91/EEC, as explained in paragraph 174.

9.12.3 Onshore Combustible Gas Storage and Recovery

549. HSE estimate that bringing hydrocarbon storage into scope of the major hazard regulations will bring approximately two onshore sites, with up to 24 wells, into scope. These newly in-scope sites will be operated by companies already compliant voluntarily. We expect they will continue to comply as they are doing currently on these sites, and so there is not expected to be any additional cost above what would occur in the baseline.

550. However, to give an indicative cost, as discussed in paragraph 546, the annual cost of a site being in scope of the onshore regulations are estimated to be between around £34.4 thousand and £42.1 thousand, with a best estimate of around £38.2 thousand. This estimate was supported in consultation.

551. This gives a total annual cost for the two sites of between around £69 thousand and £84 thousand, with a best estimate of around £76 thousand. These sites are already operational and so these costs would start to be borne from the start of the appraisal period.

552. This gives an estimated present value over ten years of between about £593 thousand and £724 thousand, with a best estimate of around £658 thousand. However, as we expect these sites to be compliant anyway, this is not an additional cost.

9.12.4 Reporting well dangerous occurrences

553. As well as becoming compliant with BSOR and DCR, UCG and hydrocarbon storage sites would also be required to comply with RIDDOR reporting of Dangerous Occurrences with respect to wells. HSE estimate that currently around 43 such reports are made per annum and that the inclusion of the four

sites described above might result in only another one or two reports over the ten year appraisal period. HSE estimate that each report takes between 1 and 4 hours to complete and that this is done by a Health, Environmental and Safety manager at an FEC of around £71.67.

554. As such, any additional cost is expected to be minimal. Furthermore, were these reports produced by hydrocarbon storage sites that are expected to be compliant voluntarily, they would pose no additional cost; and were they produced by UCG sites, the cost would be in scope of Directive 92/91 and so be out of scope of OITO.

555. Therefore, this analysis estimates that there would be **no or negligible costs to industry or the regulator** of these proposed measures. This was supported in consultation.

9.12.5 Further reducing the stock of offshore regulations

556. In total HSE expects to reduce the stock of offshore regulations by three, as discussed in Section 8.9.2. This may result in a small amount of work for industry to familiarise with the changes, but this is estimated to be lost in familiarisation with the wider changes to the regulations under the Directive. As this reduction in the stock of regulations would not, in itself, change the requirements on industry, there are expected to be **no costs or savings to industry or the regulator**.

9.13 Benefits

9.12.1 Major accidents relating to offshore oil and gas operations

557. The intention of the Directive is to reduce the likelihood of major accidents relating to offshore oil and gas operations and to limit their consequences. This should collectively provide further protection for the safety of offshore workers and limit potential damage to infrastructure, increase the protection of the marine environment and coastal economies against pollution and mitigate the consequences of major environmental accidents.

558. In the event of an incident, the measures in the Directive further strengthen the response mechanisms that are currently in place and ensure that there are funds available to cover first party costs (well control) and third party costs (caused by pollution damage). In addition, the extension to the Environmental Liability Directive will ensure water damage is covered in all marine waters within the scope of the Marine Strategy Framework Directive.

559. Major accidents offshore are rare, but when they do happen they are likely to have devastating and irreversible consequences:

560. The Deepwater Horizon disaster (Gulf of Mexico 2010) demonstrated how huge and far-reaching the consequences of a single accident can be, particularly as regards to maritime and coastal pollution. Eleven people lost their lives, an estimated 4.9 million barrels (660,000 tonnes) of oil were spilled into the sea and a state-of-the-art drilling rig, valued at US $560 million was written off as a total

loss of the disaster."[28] The oil spill occasioned a response effort involving 48,000 people, 6,500 vessels and 125 aircraft at its peak. [29]

561. More recently, in UK waters in 2012, a major gas release occurred on the Total E&P UL Ltd Elgin Offshore Wellhead platform. Personnel on the platform and an adjacent drilling rig were evacuated without injury but HSE declared the gas release a Major Incident. It took 51 days to successfully "kill" the well[30] and Total estimated that the closures cost around £1.4 billion in lost revenues, as well as £250 million in costs dealing with the incident.

562. Taking the measures outlined in this Impact Assessment to further mitigate the risk of an offshore major accident will also help to maintain public and investor confidence in the UK's offshore oil and gas industry. The indirect impacts of offshore major accidents, the effects on oil prices (and the knock-on effect on other goods and services) and the security of energy supply, for example, can all have affect the UK's economy. Major accidents can also have big impacts on the reputation of a company and affect share prices. BP reported that following the Deepwater Horizon incident, its shares lost more than half their value and in order to pay the related costs (clean-up costs, claims from affected businesses/individuals, penalties etc.) the company suspended dividend payments and needed to set up a $30 billion asset divestment programme. [31]

563. It is not possible to estimate the reduction in risk or frequency of major accidents brought about by the Directive and so estimate or monetise benefits, as these are rare events and the baseline risk is not possible to estimate. However, the costs described above should serve to illustrate the magnitude of possible benefits (both to business and to society as a whole) if the measures only serve to reduce risk by a small amount.

9.12.2 Increased oversight of the CA

564. The joint CA is expected to further strengthen the existing robust regimes for environmental and safety major accident regulation in the UK by providing greater oversight and assessing the risks holistically. The risk of a major accident is already well controlled by the existing regimes operated by HSE and DECC. It is not possible to estimate any reduction in the risk of a major accident from the operation of the joint CA. However it is anticipated to be very small given the mature and robust nature of the UK's present regulatory structure. As such, this benefit is expected to be minimal and not possible to quantify.

9.12.3 Single point of contact

565. The joint CA and implementation of a single online portal would allow owners and operators to submit health, safety and environmental information to the regulator at a single point of contact and avoid duplication. The online portal would also collect information on the regulations and guidance for owners and operators in one place, rather than having it hosted on separate websites. This might deliver some savings to business in the administrative burdens of seeking

[28] Figures from Transocean Ltd reported in the EC Impact Assessment for the 'Proposal for a regulations of the European Parliament and of the Council' Brussels, 27.10.2011

[29] BP sustainability Review, 2010, cited in the EC Impact Assessment (As above)

[30] A 'well kill' involves stopping a bore hole with heavy fluids to prevent further release.

[31] EC Impact Assessment (as above)

out and submitting information to the regulator. However, this is expected to be small and has not been quantified.

9.12.4 Joint inspection visits

566. It is anticipated that the joint HSE-DECC CA may deliver savings to industry through joint visits by HSE and DECC inspectors. This may deliver a saving to industry in terms of the time spent preparing for the visit and escorting the inspectors, whether an onshore office visit or an offshore installation visit. However, it would not deliver savings in terms of the cost of transporting inspectors or providing accommodation nor in any costs recovered for inspector time.

567. The industry research group were able to estimate the cost of their time spent managing these visits based on past experience. They estimated that for one onshore inspection visit the total cost of time was between around £15 thousand and £20 thousand, with a best estimate of around £17.5 thousand. This is the equivalent of between around 209 hours and 279 hours of a Health, Safety and Environment Manager, with a best estimate of around 244 hours.

568. They also estimated that for one offshore inspection visit the total cost of time was between around £25 thousand and £35 thousand, with a best estimate of around £30 thousand. This is the equivalent of between around 349 hours and 488 hours of a Health, Safety and Environment Manager, with a best estimate of around 419 hours.

569. It has not been possible to estimate how many inspection visits might be saved through the joint-working of the CA.

9.12.5 Underground Coal Gasification & Onshore Combustible Gas Storage and Recovery

570. The extension of the onshore regulations to cover underground coal gasification (UCG) and combustible gas storage and recovery is viewed by HSE as necessary to regulate risks to employees and members of the public in a robust and proportionate manner. In this way, HSE expects that this will reduce the risk of injury, fatality and major accident over the ten-year appraisal period. However, this reduction cannot be quantified.

571. In addition, where the application of the well-established onshore regulations to these emerging sectors provides a greater assurance of reduced health and safety operating risks, this will build public and investor confidence in these emerging sectors. This will create an environment where these emerging energy technologies are more likely to develop further (e.g. into a production stage for UCG) and so add further benefits (e.g. tax revenue) to the UK economic longer-term.

9.13 Summary of Costs and Benefits

572. Table 17 summarises all quantified costs and benefits to industry and Government.

Table 17: Summarised quantified costs and benefits of Option 2 (£thousands)

	Low	Best Estimate	High
<u>Costs to Government</u>			
Setting Up the Competent Authority	£1,264	£1,451	£1,644
Operating the Competent Authority	£1,244	£1,418	£1,591
Updates to Licensing Authority Systems			
Updating licensing systems	£20	£20	£20
Updating IT portal for operatorship	£55	£55	£55
TOTAL Cost to Government	**£2,583**	**£2,943**	**£3,311**
<u>Costs to Industry</u>			
CA Assessments Related to HSE Legislation	£7,645	£8,499	£9,354
CA Assessments Related to DECC Legislation	£1,181	£1,312	£1,442
CA Assessments Related to DECC Licensing Legislation	£3,041	£3,379	£3,717
Costs of Complying with Changes to HSE Legislation	£81,010	£149,894	£218,983
Costs of Complying with DECC Environmental Legislation	£10,097	£24,308	£38,520
Costs of Complying with Legislation to Implement Article 38	£66	£247	£428
Costs of Complying with Changes to Additional HSE Legislation	£331	£368	£404
Costs of Complying with DECC Licensing Legislation	£4,895	£5,438	£5,982
Costs of Gold Plating of HSE Legislation	Nil	Nil	Nil
Costs of Gold Plating of DECC Legislation	Nil	Nil	Nil
TOTAL Cost to Industry	**£108,266**	**£193,444**	**£278,829**
<u>Benefits</u>			
Benefits	Unquantified	Unquantified	Unquantified
<u>Cost Savings</u>			
Mitigation of water damage from any compensation under Article 38	£0	£181	£362
NET TOTAL	**£110,849**	**£196,207**	**£281,778**
Government and Wider Society Net Total	**£2,583**	**£2,763**	**£2,949**
Industry Net Total	**£108,266**	**£193,444**	**£278,829**

Note: continued on next page. Figures are ten-year present values. Totals may not sum due to rounding.

10 Rationale and evidence that justify the level of analysis used in the IA (proportionality approach)

573. The methods used to collect evidence on the costs to industry for this final stage IA are described in Section 6. In summary, they have consisted of two phases of research group meetings with industry representatives. These have allowed us to estimate costs of compliance with the onshore and offshore major hazard regulations as they currently stand and the costs necessary to achieve compliance with the proposed changes under the Directive. The close involvement of industry in this process has allowed us to better understand the measures industry would need to take to achieve compliance and the costs they would incur in doing so.

574. Further evidence on issues after consultation was gathered with stakeholders through correspondence and interviews. In some cases, these included members of the initial research groups, enabling the analysis to build upon their knowledge and experience of the Regulations and costing methods.

575. Further evidence on the costs to the CA to be recovered from industry has been gathered through questionnaires and discussions with representatives from the CA joint working group and inspectors/specialists from both HSE and DECC.

576. Considerable resources both in terms of the time of officials and of industry have gone into the analysis in this Impact Assessment. This is thought to be proportionate to the significant impact on industry and Government resulting from the Offshore Safety Directive.

11 Direct costs and benefits to business calculations (following OITO methodology)

577. Option 2 imposes a ten-year present value net cost on society of between around £111 million and £282 million, with a best estimate of around £196 million.

578. Of this ten-year present value, the net costs to Government and wider society would be between around £2.6 million and £2.9 million, with a best estimate of around £2.8 million.

579. The ten-year present value cost to industry would be between around £108 million and £279 million, with a best estimate of around £193 million.

580. This gives an Equivalent Annual Net Cost to Business of around £17.1 million in 2009 prices. As these measures implement European Directives, they are out of scope of OITO.

581. Of this EANCB in 2009 prices, £0.03 million represents costs not associated with the minimum implementation of the Directive: that is, the costs around underground coal gasification (see paragraphs 546 to 548).

582. Of the £17.06 million EANCB from implementation of the Directive:

- £0.02 million represents the costs to business as a result of the Offshore Safety Directive's changing of the scope of the Environmental Liability Directive (see paragraphs 526 to 544);

- changes to HSE legislation account for £14.0 million;

- and changes to DECC legislation, £3.04 million.

583. Where Directive measures are gold plated, this maintains a current standard and therefore does so at zero additional cost.

12 Wider impacts

584. Wider impacts have been considered and no impacts have been identified for:
- Statutory Equality Duties;
- Competition
- Human Rights;
- Justice System;
- Rural Proofing, and
- Social Impacts
- Sustainable development

12.1 Competition

585. Companies will be required to provide evidence that they have financial liability arrangements in place to meet the costs associated with an oil pollution incident. The industry is already providing evidence in relation to exploration and appraisal well drilling and there has been no indication that this impacted negatively on smaller companies. The requirement will now be extended to production operations, but it is not considered that this will place a significant new burden on the industry as it is considered that they will already have such provision in place.

12.2 Small and Micro-businesses

586. European Directive requirements apply to all businesses, therefore small and micro businesses will need to comply with the new legislation that implements these requirements. However, it is important to note that major hazard risks are not proportionate to business size, and the potential for poorly managed risks leading to a major accident with catastrophic consequences is the same for small businesses as it is for large international companies. In the light of the Deepwater Horizon disaster (Gulf of Mexico 2013) and the subsequent close scrutiny of the UK offshore industry, it is crucial that all businesses operating offshore, regardless of size, are subject to the same regulatory regime to ensure that they continue to provide a high level of protection for the safety of the workforce and the marine environment.

587. There is one proposal in this Impact Assessment that is not derived from a European Directive, for new domestic requirements that relate to combustible gas storage and recovery. The small business assessment has highlighted that the

majority of companies involved in this activity are not micro businesses, but there are one or two operators who may have fewer than 10 employees. However, the major hazard risks associated with onshore gas storage and recovery (e.g. hydrocarbon gas being released and ignited leading to an explosion) are not proportionate to the number of employees. These risks can result in death or injury to workers and the public, as well as damage to assets and the reputation of an emerging energy technology. In order to avoid the devastating impacts of such major accidents, it is important to apply the same approach to managing and controlling these risks to all businesses. The reality is that all businesses working in this sector (large or small) are currently voluntarily complying with the standards.

588. This robust regulatory approach also provides assurance to industry that all businesses, regardless of size, are operating to the same required standard. It could be argued, therefore, that this regime creates a level playing field and enables smaller businesses to compete with larger companies. If the requirements were not applied to smaller businesses, they might find it harder to tender for contracts and would actually be placed at a competitive disadvantage.

12.3 Environmental impacts

589. We have considered the criteria for wider environmental impacts and do not consider that there is anything that needs to be addressed other than the environmental impacts that are addressed in the main body of the IA and in the benefits section.

12.4 Health and Well Being

590. We have considered the criteria for wider health and wellbeing impacts and do not consider that there is anything that needs to be addressed other than the health and safety impacts that are addressed in the main body of the IA and in the benefits section

13 Summary and preferred option with description of implementation plan

591. The Directive requires member states to establish a new offshore CA. The preferred option (Option 2) is to extend DECC and HSE's existing arrangements and establish a partnership CA that will oversee industry compliance with the Directive and deliver the CA functions specified in the Directive.

592. The implementation plan is to maintain as much as possible of the current offshore safety and environmental regulatory regimes and minimise burdens on industry. Many of the Directive requirements are already met by domestic legislation or existing arrangements and these will be extended or amended to incorporate new requirements. The majority of requirements will be implemented via new Offshore Installations (Safety Case) Regulations 2015 (SCR 2015) which will replace the SCR 2005. The remaining requirements will be implemented via the Offshore Petroleum Activities (Offshore Safety Directive) Regulations 2015 that will amend the Merchant Shipping (Oil Pollution

Preparedness, Response Co-operation Convention) Regulations 1998. Where it is considered proportionate to maintain a pre-existing standard higher than required by the Directive, this has been retained.

593. Option 2 imposes a ten-year present value net cost on society of between around £111 million and £282 million, with a best estimate of around £196 million.

594. Of this ten-year present value, the net costs to Government and wider society would be between around £2.6 million and £2.9 million, with a best estimate of around £2.8 million.

595. The ten-year present value cost to industry would be between around £108 million and £279 million, with a best estimate of around £193 million.

596. This gives an Equivalent Annual Net Cost to Business of around £17.1 million in 2009 prices. As these measures implement European Directives, they are out of scope of OITO. This is broken down as shown in Table 18.

Table 18: Summary of Equivalent annual Net Cost to Business (EANCB) in 2009 prices (£millions)

Measure	**EANCB**
Implementation of the Offshore Safety Directive	£17.06
Of which, related to HSE legislation	*£14.00*
Of which, related to DECC legislation	*£3.04*
Of which, Environmental Liability Directive (Defra)	*£0.02*
Of which, gold plating	*Nil*
Underground coal gasification (HSE)	£0.03
TOTAL	**£17.09**

597. Of this EANCB in 2009 prices, £0.03 million represents costs not associated with the minimum implementation of the Directive: that is, the costs around underground coal gasification (see paragraphs 546 to 548).

598. Of the £17.06 million EANCB from implementation of the Directive:

- £0.02 million represents the costs to business as a result of the Offshore Safety Directive's changing of the scope of the Environmental Liability Directive (see paragraphs 526 to 544);

- changes to HSE legislation account for £14.0 million;

- and changes to DECC legislation, £3.04 million.

599. Where Directive measures are gold plated, this maintains a current standard and therefore does so at zero additional cost.

Annex: Glossary of Acronyms

BSOR	Borehole Sites and Operations Regulations 1995
CA	Competent Authority
CMAPP	Corporate Major Accident Prevention Policy
COMAH	Control of Major Accident Hazards Regulation 1999
DECC	Department of Energy and Climate Change
Defra	Department for Environment, Food and Rural Affairs
DCR	Offshore Installations and Wells (Design and Construction, etc) Regulations 1996
DfT	Department for Transport
ECE	Environment-Critical Element
ELD	Environmental Liability Directive
EMS	Environmental Management System
EO	Executive Officer
EUOAG	European Union Offshore Oil and Gas Authorities Group
FEC	Full Economic Cost
HASWA	Health and Safety at Work etc Act 1974
HEO	Higher Executive Officer
HSE	Health and Safety Executive
HSE ED	Health and Safety Executive Energy Division
IA	Impact Assessment
ICP	Independent Competent Person (or well verifier)
IERP	Internal Emergency Response Plan
MAR	The Offshore Installations and Pipeline Works (Management and Administration) Regulations 1995
MCA	Maritime and Coastguard Agency
MoU	Memorandum of Understanding
MSFD	Marine Strategy Framework Directive
NPI	Non-Production Installation
NPV	Net Present Value
OGED	DECC Offshore Oil and Gas Environment and Decommissioning
ONR	Office for Nuclear Regulation
OPEP	Oil Pollution Emergency Plan
OPRC	Merchant Shipping (Oil Pollution Preparedness, Response Co-operation Convention) Regulations 1998
OSPAR	The Oslo Paris Convention for the Protection of the Marine Environment of the North-East Atlantic
PFEER	The Offshore Installations (Prevention of Fire and Explosion, Emergency Response) Regulations 1995
PI	Production Installation
RIDDOR	Reporting of Injuries, Diseases and Dangerous Occurrences Regulations 2013
SCE	Safety-Critical Element
SCR	Offshore Installations (Safety Case) Regulations
SECE	Safety- and Environmental-Critical Element
SEMS	Safety and Environmental Management System
SEO	Senior Executive Officer
SMS	Safety Management System
SoS	Secretary of State
UCG	Underground Coal Gasification
UKCS	United Kingdom Continental Shelf