Review of *Environmental Impact Study* for Repsol's Proposed 2014 *Exploratory Offshore Drilling, Canary Islands, Spain.*

Expert Report
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I. Introduction

1. This expert report was commissioned by the Fuerteventura Council, Canary Islands, Spain. The Council requested an independent technical review of two principal, safety-critical aspects of the Repsol Investigaciones Petroliferas, SA (RIPSA) *Environmental Impact Study for the Canary Island Offshore Exploratory Drilling project* (released August 2013): A. the risk, prevention, and control of a loss of well control event - "blowout" - during deepwater drilling, and; B. the oil spill response plan.

2. Specifically, the Council requested that the review identify omissions or errors in the scope and content of the EIS, and insufficiencies in the EIS regarding its conformance with the current state of international *Best Available Techniques/Technology* (BAT) and *Best Environmental Practice* (BEP) in deepwater drilling, oil spill prevention, and oil spill response.

3. While this review focuses on the failures and insufficiencies of the Repsol EIS, it is offered respectfully, and with the sincere hope that it will assist the Fuerteventura Council, the Government of Spain, the company, and the public better understand the risks involved in the proposed deepwater drilling project, the potential effectiveness of risk mitigation measures, and to make informed decisions accordingly about the proposed project.

II. Summary of Findings

1. Overall, this review concludes that the Repsol *Canary Islands Environmental Impact Study* (EIS) is *not fit-for-purpose*, and respectfully recommends that the Government of Spain decline to accept the EIS, and deny the exploratory drilling project as currently proposed.

2. As outlined below, the EIS clearly fails to meet the required specifications stipulated in the June 6, 2013 letter to RIPSA from the Government of Spain's *Director General of Quality and Environmental Assessment and Natural Environment* (DGQEA) [http://www.magrama.gob.es/es/calidad-y-evaluacion-ambiental/temas/], *Ministry of Agriculture, Food and Environment* (MAGRAMA). The DGQEA letter embodies the basic requirements of the following:
    A. the European Commission's 2001 *Guidance on EIA, EIS Review*;
    B. the *Convention for the Protection of Marine Environment of the North-East Atlantic* (OSPAR Convention),
    C. *Directive 2013/30/EU of the European Parliament and of the Council of 12 June 2013 on Safety of Offshore Oil and Gas Operations and Amending Directive 2004/35/EC OJ L 178, 28.6.2013 (2013 EU Drilling Directive)* [http://eurlex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:32013L0030:EN:NOT], and;

D. *Legislative Royal Decree 1/2008, 11 January 2008, passing the consolidated text of the Law on the Environmental Impact of Projects, Spanish Official Journal (BOE) 23 January 26, 2008 (Royal Legislative Decree 1/2008*) [http://www.boe.es/buscar/act.php?id=BOE-A-2008-1405].

3. In the June 6, 2013 DGQEA letter, the government requires the Repsol EIS to address *in detail* all aspects of the project, including well design and construction, wellhead pressure control, description of all equipment to be used, cement, drilling muds, shallow hazards analysis, response to loss of well control (blowout), specific emergency procedures, well abandonment, and the oil spill response plan. This is a reasonable and appropriate requirement, as without such detail, the government and the public are unable to effectively assess the adequacy of safety planning for the proposed project.

4. With regard to the stipulations required by the DGQEA letter (above), the EIS is clearly insufficient. It does not provide sufficient detail with which to determine *with reasonable confidence* that the drilling project would be conducted safely, or that the emergency response plan would be effective.

5. Repsol is a global company, with operations in more than 30 countries, including the U.S. The company is well aware of, and must comply with, the safety requirements for offshore drilling in other countries, for instance, the new offshore Drilling Safety Rule in the U.S. (BSEE, 2012), established subsequent to the 2010 *Deepwater Horizon* disaster in the Gulf of Mexico (see III.A.3 below). Yet the Canaries EIS does not discuss, recognize or reflect this significant increase in safety standards for offshore drilling embodied in other national regimes, such as the new U.S. rule. In contrast, the Canaries EIS reflects a *less rigorous* deepwater drilling safety regime than the company is required to comply with in its U.S. operations. The company will need to explain and attempt to justify this *double standard* to the government and people of Spain, in particular to the people of the Canary Islands.

6. The EIS briefly mentions *Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations* (EU, 2013), and states that, while not mandatory, "RIPSA will comply with the obligations under the Directive" (EIS, p. 45). However, the EIS does not discuss the requirements of this *2013 EU Drilling Directive* further. The *2013 EU Drilling Directive* substantially enhances offshore safety requirements throughout all EU member states. In particular, it requires that offshore operators clearly identify all major hazards, conduct risk assessments of such hazards, and implement a robust risk mitigation/risk reduction program to *As Far As Possible*. The Repsol EIS does not provide evidence that RIPSA indeed intends to comply with this important new *EU Drilling Directive*. To the contrary, the EIS clearly fails to meet the enhanced drilling safety requirements established by the new *Directive*.

7. The EIS does not cite, meet, or exceed the standards established in new offshore Drilling Safety Rule in the U.S. (BSEE, 2012) as a BAT/BEP standard, and such omission directly contravenes requirements in the OSPAR Convention, the European Commission's *Guidance on EIA/EIS Review*, the *2013 EU Drilling Directive*, *Legislative Royal Decree 1/2008*, and as stipulated in the June 6, 2013 DGQEA letter to RIPSA. In this regard, OSPAR states that *Best Available Techniques* (BAT) and *Best Environmental Practice* (BEP) for a particular process "will change with time, in light of technological advances, economic, and social factors, as well as changes in scientific knowledge and understanding" (Appendix 1.3, OSPAR Convention). Clearly, the new offshore Drilling Safety Rule in the U.S., which resulted from an exhaustive technical review of all safety-critical offshore drilling issues in U.S. waters subsequent to the 2010 *Deepwater Horizon* tragedy, reflects such "advances in scientific knowledge and understanding," and is the very sort of advance in BAT/BEP that OSPAR requires to be incorporated into all EIS documents.

8. The EIS does not present a *Best Available Techniques/Technology* (BAT) and *Best Environmental Practice* (BEP) safety case for the project or company, does not evidence serious attention to detail and risks of the project, or demonstrate due diligence by the company.

9. While the company may intend to address some of the omissions in the EIS in subsequent submissions to the government, the lack of detail at this stage makes it impossible to adequately assess risks and potential impacts of the project, or to confirm the company's risk mitigation claims, as clearly required by the DGQEA. And as the EIS anticipates the commencement of drilling in the second half of 2014, most of these decisions should clearly have already been made, presented, reviewed, and approved by this point in time.

10. The EIS does not actually present a specific "proposed action," but proposes a range of alternatives for development, including the specific wells to be drilled, general well designs, drilling rigs to be used, muds to be used, and drilling waste discharge regimes. It does not present a "preferred alternative" or specific "proposed action" (as is required by U.S. law and *Directive 2011/92/ EU*, see article 5.3.d (http://eurlex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2012:026:0001:0021:EN:PDF). While the EIS concludes that the difference in risks and potential impacts between the alternatives is inconsequential, this is a questionable assertion. Prior to further consideration of the project by the Government of Spain, the company should present a specific and detailed proposed action.

11. The EIS *understates the risks and potential impacts* of the proposed project, and fails to envision the many ways in which a complex system such as a

deepwater drilling project can fail, and produce a low probability, high consequence event, such as a major blowout. In the post-*Deepwater Horizon* understanding of deepwater drilling risks, this is unacceptable.

12. The EIS *overstates the potential effectiveness of the project's risk mitigation and response plans*. Many of the claims in the EIS regarding risk mitigation are qualitative, vague, and unsubstantiated.

13. The EIS does not discuss the additional risk posed by drilling *High Pressure High Temperature* (HPHT) wells. It is clear that the proposed drilling project should be considered a high-risk exploratory drilling operation, particularly the deep wells proposed at Zanahoria 1 and Cebolla 1, which should be considered HPHT wells, and accorded additional risk reduction safeguards and detail in the EIS.

14. The EIS does not provide sufficient detail regarding safety-critical aspects of the project's specific well designs, construction, monitoring, testing and inspection, mud engineering, cementing, pressure testing, kick detection, well abandonment, and management. All of these are required to be detailed, as stipulated in the June 6, 2013 letter from the DGQEA to RIPSA, and other directives referenced above.

15. The EIS admits that the operating company (RIPSA) has yet to develop a detailed well-integrity plan, a *Blowout Contingency Plan* (BOCP), a contract with a well-capping contractor, or a contract and plan to drill a relief well in response to a blowout. Despite this, the EIS claims that the company's risk reduction and well control procedures, which are still "in development," will substantially reduce the overall risk to the local environment.

16. The EIS states that: "The implementation of preventive and corrective measures proposed for the project (see Table 3 in Synthesis) is intended to reduce potential harm anticipated, achieving the level of risk management to the lowest level that is reasonably practicable (ALARP)." But this table contains only a general qualitative list of basic well control procedures that could be found in any basic introductory drilling text. There is no detail provided to any of these procedures. As such, this simply cannot be used to substantiate the risk reduction claims made in the EIS.

17. The EIS does not commit to *Best Available Techniques/Technology* (BAT) or *Best Environmental Practice* (BEP) for the *Blowout Preventers* that would be placed on the subsea wellheads. It cites the company's intent to "take into consideration the recommendations of API (American Petroleum Institute) Standard 53" - *Blowout Prevention Equipment Systems for Drilling Wells* - but it does not commit *to comply* with API Standard 53. It must be noted that most provisions for safe BOP installation and operation in API Standard 53 are *required*, not just optional *recommendations*. As well, Repsol is required

to comply with this standard in its U.S. offshore operations, and is implicitly required to meet this BAT standard by the *2013 EU Drilling Directive* and the DGQEA letter.

18. The EIS does not provide detailed information regarding the training, experience, and competencies of company or subcontractor personnel, both on the rigs and onshore, as is required in the DGQEA letter.

19. The EIS does not present a *Critical Operations and Curtailment Plan* (COCP), for moving off location during an emergency situation, as is required in the U.S. and implied in the *2013 EU Drilling Directive*. The COCP needs to detail specific procedures for responding to such things as adverse weather; unavailability of equipment, materials, or personnel; or well control issues. The COCP needs to identify planned and unplanned critical operations, such as drilling into a zone capable of flowing oil or gas, coring, pulling out of the hole, wire logging, running casing, circulating, cementing, attempting to retrieve lost items in the well, open-hole sidetracking, drilling into a lost circulation zone, remedial well work, anchor line tensioning, refueling, or accidental riser disconnect. The COCP must identify the amount of time expected to secure the drilling operation, including time (in hours) necessary to disconnect the Lower Marine Riser Package (LMRP) from the BOP and temporarily abandon the well, and to move off the site. And the COCP must clearly establish a drilling curtailment decision process, as well as training of key personnel in this process.

20. The EIS confirms that an *inadequate* risk reduction standard would be used for the project. As is clear in June 6, 2013 DGQEA letter to RIPSA, *Best Available Techniques/Technology* (BAT), also called Best Available & Safest Technology (as required in U.S. regulation), and *Best Environmental Practice* (BEP), is required by the Government of Spain, and the *2013 EU Drilling Directive*. However, it is clear from the EIS that RIPSA does not intend to meet a BAT/BEP standard. To the contrary, the EIS states that the operator will employ a risk reduction standard of *As Low As Reasonably Practicable* (ALARP). ALARP implies that not all *Best Available Techniques/Technology* risk reduction measures will be incorporated in the project, particularly if they are deemed too costly, too difficult, too time-consuming, or otherwise "not reasonably practicable," at the discretion of the company. In essence, ALARP is not BAT/BEP. Given the exceptional and sensitive environmental resources found in the Canary Islands, this region should clearly be considered a *High Consequence Area* (HCA) for oil development (as defined in API standards), thereby requiring enhanced design and operational standards to reduce risk to *As Low As Possible* ("ALAP"). Additionally, *Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations* (EU, 2013) similarly requires risk to be reduced to *As Far As Possible.*

21. The EIS establishes an unrealistically small "worst case" blowout scenario for the project of 1,000 bbls/day for 30 days. By comparison, the initial flow rate estimated from the 2010 *Deepwater Horizon* Macondo blowout was 100,000 bbls/day, declining over time (as reservoir pressure declined) to an estimated average of 62,000 bbls/day, for a total duration of 87 days, giving a total spill volume of 4.9 million bbls (of which 800,000 bbls was reportedly collected at the wellhead). The Repsol EIS should provide a rationale as to why a Macondo-size discharge is not considered a possible worst case scenario for the Canaries project.

22. The EIS should establish a more realistic, and larger, worst case blowout scenario. Given that the depth, pressures, and operational complexities likely to be encountered in some of the deepwater Canaries wells may equal or exceed those for the Macondo well, a more reasonable worst case blowout scenario for the Canaries drilling project would be 30,000 bbls/day for 60 days, or 1.8 million bbls total discharge. This is 60 times larger than the "worst case" scenario considered in the EIS. This larger, more reasonable worst case discharge will significantly alter the findings of the oil spill modeling simulations regarding the area potentially impacted, surface and shoreline oiling, and predictions regarding severity of environmental impacts.

23. The scientific literature on well control cited in the EIS is insufficient. Extensive references are cited in the biological and socioeconomic impact sections, but only a surprisingly short list of citations for well design and control, and response to a loss of well control. For instance, the EIS does not incorporate the extensive amount of technical understanding of these issues gained from the *Deepwater Horizon* disaster in the U.S. Gulf of Mexico. At least 12 detailed technical studies have been published on the causes and consequences of the *Deepwater Horizon* disaster, by industry, government, independent commissions, and academia (see references below). Surprisingly, none of these studies were cited in the Repsol EIS. As well, the EIS does not provide a comprehensive review of other deepwater blowout literature. This reflects a dangerously dismissive attitude toward lessons learned in other deepwater disasters, and an aversion to incorporating such experience into the proposed drilling program.

24. The EIS does not cite literature regarding extensive scientific studies that have been conducted on the *Deepwater Horizon* spill in the Gulf of Mexico, or the long-term studies on impacts from the 1989 *Exxon Valdez* oil spill in Alaska. This reflects a lack of consideration for the breadth of scientific information regarding potential environmental consequences of major marine oil spills.

25. The *Oil Spill Contingency Plan* (PICCMA) in the EIS is insufficient. It is very basic and general, still only "preliminary," and flawed in many respects. Dispersant products and application protocols are not detailed, in-situ

burning is not discussed, equipment capabilities are not specified, response limitations are not discussed, and spill drills are not sufficiently detailed.

26. The oil spill simulation model is insufficient, as it models only the modest scenario asserted as "worst case," and the simulation only extends for 45 days. Even in the modest spill scenario, oil would certainly remain in the environment for much longer than 45 days, and travel much farther than the model presents.

27. Alternative Zero – the "no development" alternative – is inadequately assessed. As written, it focuses primarily on the economic *costs* that would derive from selection of this alternative, but not the economic *benefits*. There are many potential economic benefits from this alternative, including protection and expansion of existing economic activities such as tourism, recreational fishing, and commercial fishing, as well as the intangible aesthetic, and non-market, or "contingent value" economic benefits.

28. Given the high ecological sensitivity of the coastal and offshore environment of the Canary Islands, the high risk of exploratory drilling in deepwater reservoirs, the reviewer feels that, prior to any further consideration of the proposed project, the Government of Spain and the people of the Canary Islands would need a much more deliberate, comprehensive, and carefully developed EIS, in particular regarding well integrity and control, blowout response, and oil spill response, prior to permitting such development. These should be discussed.

III. <u>Deepwater Drilling Risk</u>

<u>A. General</u>

1. It is widely understood that there is a dangerously slim margin of error in drilling deepwater wells, particularly *High Pressure High Temperature* (HPHT) wells, and consequences of failure are potentially catastrophic. Equipment needs to be tested and demonstrated to perform in the HPHT conditions expected in the wells (see Anderson et. al., 1998). For instance, the oil spill simulation model presented in the EIS projects oil temperatures for the Zanahoria well of 153 C, and for Cebolla of 151 C. By comparison, oil in the Macondo well was reported to be 130 C, with reservoir pressure at 13,000 psi. It is also possible that pressures would be correspondingly greater in the deep Canaries wells.

2. The EIS does not discuss the issue of HPHT drilling, or refer to the UK government's *Model Code of Safe Practice* for HPHT wells. In this code, drill crews must have demonstrated experience in working as a team prior to drilling HPHT wells. Pre-drilling training sessions, and manuals and checklists detailing procedures for drilling, well control, completion and

abandonment, personnel tasks, and emergency response are needed. "Non-routine" operations meetings must be established in which to discuss any non-standard operation before commencement. And crew changes need to be methodically conducted, including a pre-tour meeting, and checklists of critical parameters that will be communicated to the incoming crew.

3. The EIS fails to recognize and reflect the increased safety standards imposed in the U.S. after the 2010 *Deepwater Horizon* disaster (BSEE, 2012). In particular, the EIS must discuss the new U.S. *Bureau of Safety and Environmental Enforcement* (BSEE) Final Rule (30 CFR Part 250) published on August 10, 2012: *Oil and Gas and Sulphur Operations on the Outer Continental Shelf–Increased Safety Measures for Energy Development on the Outer Continental Shelf*. This new offshore Drilling Safety Rule in the U.S., with which Repsol must comply in its U.S. offshore projects, establishes new casing installation requirements, new cementing requirements, requires independent third-party verification of blind shear ram (BSR) capability and subsea BOP stack compatibility, requires new casing and cementing integrity tests, establishes new requirements for subsea secondary BOP intervention, requires function testing for subsea secondary BOP intervention, requires documentation for BOP inspections and maintenance, requires a Registered Professional Engineer to certify casing and cementing requirements, and establishes new requirements for specific well control training to include deepwater operations.

4. The EIS does not discuss in detail the new requirements of *Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations,* with which Spain is required to comply, and ensure that offshore operators, such as Repsol, fully comply (EU, 2013). The EIS states that *RIPSA will comply with obligations under the Directive*, but clearly does not evidence such. The *2013 EU Drilling Directive* substantially enhances offshore safety requirements throughout all EU member states. In particular, it requires that offshore operators clearly identify all potential major hazards, a comprehensive risk assessment of such hazards, a robust risk mitigation/reduction program, an effective safety and environmental management system, independent verification, and a detailed emergency preparedness and response plan. In particular, the EIS fails to meet requirements in Article 9: *Documents to be submitted*; Article 11: *Report on major hazards for a non-production installation*; Article 12: *Internal emergency response plans;* Article 15: *Independent verification*; and Article 21: *Confidential reporting of safety concerns*. The Repsol EIS clearly fails to meet these requirements.

5. The Repsol corporate environmental management strategy, as discussed on the company website, states the following with regard to oil spill management: *Our focus is placed on adopting the most advanced techniques for the prevention, pollution remediation and management of accidental spills.* However, the company's Canaries EIS simply does not reflect this corporate

strategy, in particular the assertion that the company will adopt the *most advanced technologies* in its spill prevention and response preparedness, as discussed by this review.

6. The EIS does not demonstrate that the operating company (RIPSA) has an integrated risk management system in place with which to address the complexities and risks of deepwater drilling, including a system for obtaining real-time independent expert review and opinion at all stages of the drilling project.

7. The EIS does not sufficiently envision and plan for catastrophic failure, which it does only superficially. To the contrary, it assumes success. This attitude invites a dangerous lack of vigilance and complacency. It should be noted that just 5 months prior to the *Deepwater Horizon* disaster in the Gulf of Mexico, representatives of the U.S. oil industry and government regulators, in testimony to a U.S. Senate hearing regarding the August 2009 *Montara* offshore platform blowout in the West Timor Sea (NW Australia), assured the U.S. Congress that offshore drilling in the Gulf of Mexico was perfectly safe, and the regulatory process was sufficient. This very same dangerous complacency is evident in the Repsol EIS.

8. The EIS does not present a comprehensive Risk Assessment of the specific wells proposed, and identify all potential failure points and scenarios, incorporating what is known about the geology of the formation. This is required in *Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations* (EU, 2013), which requires all offshore operators to identify all potential "major hazards" posed by a project.

9. The EIS does not present sufficient discussion of all inspection regimes, and training and qualifications of personnel, or third party expert review of the drilling plan.

10. The EIS states that the risk reduction standard to be used is *As Low As Reasonably Practicable* (ALARP). Yet, ALARP is not BAT/BEP, and is not a sufficient standard for high-risk, deepwater drilling operations in biologically sensitive environments. ALARP implies that more costly, time consuming, or safety measures that might be considered not "practicable" are not necessary, and this is unacceptable for a region as sensitive as the Canary Islands. The risk reduction standard should be elevated to *As Low As Possible* (ALAP), employing *Best Available Technology* (BAT) and *Best Environmental Practice* (BEP), as required by the Government of Spain, as well as required by *Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations* (EU, 2013).

11. The EIS does not contain a complete casualty history for Repsol offshore drilling projects, as well as for the specific rigs to be used (which have yet to be identified). This information is necessary to evaluate the company's

assertions regarding its safety management programs, and is required in *Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations* (EU, 2013).

12. The EIS does not detail responsibilities and relationships between all project participants, including the rig owner, the captain of the vessels, Offshore Installation Manager (OIM), and all subcontractors.

13. While the EIS cites the company's intent to "take into consideration the recommendations of API (American Petroleum Institute) Standard 53": *Blowout Prevention Equipment Systems for Drilling Wells,* it does not commit the company to *comply* with this standard, as required in the U.S. (see BOP section below).

14. The EIS omits any reference to, or commitment to comply with, other important API Standards, including, but not limited to, the following: API Recommended Practice (RP) 65 Part 2: *Isolating Potential Flow Zones During Well Construction*, addressing best practices for cementing; API Spec 16A: *Specification for Drill-Through Equipment*; API Spec 16D: *Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment*; API Spec 17D: *Specification for Subsea Wellhead and Christmas Tree Equipment*; API RP 17H; ISO 13628-8: *Remotely Operated Vehicle (ROV) Interfaces on Subsea Production Systems;* and API RP 75: *Development of a Safety and Environmental Management Program for Offshore Operations and Facilities*. Many of these are incorporated by reference into the new U.S. offshore Drilling Safety Rule (BSEE, 2012), with which Repsol is required to comply in its U.S. offshore projects. And the need to comply with these standards is implied in the *2013 EU Drilling Directive* (EU, 2013).

15. The EIS does not include a *Critical Operations and Curtailment Plan* (COCP), as required in the U.S. and implied in the *2013 EU Drilling Directive*, for moving off location during an emergency situation. The COCP needs to detail specific procedures for responding to such things as adverse weather; unavailability of equipment, materials, or personnel; or well control issues. The COCP needs to identify planned and unplanned critical operations, such as drilling into a zone capable of flowing oil or gas, coring, pulling out of the hole, wire logging, running casing, circulating, cementing, fishing for lost items in the well, open-hole sidetracking, drilling into a lost circulation zone, remedial well work, anchor line tensioning, refueling, or accidental riser disconnect. The COCP must identify the amount of time expected to secure the drilling operation, including time (in hours) necessary to disconnect the Lower Marine Riser Package (LMRP) from the BOP and temporarily abandon the well, and time necessary (in hours) to move off the site. And the COCP must clearly establish a drilling curtailment decision process, as well as training of key personnel.

16. The EIS needs to detail the weather-operating protocols, and adverse weather shutdown procedures during drilling. This needs to establish what weather and sea conditions will require a drilling shutdown and/or a disconnect from the riser and wellhead, and a specific process for making such decisions. This should be detailed in the *Critical Operations and Curtailment Plan* (discussed above), which is not provided.

B. Well Design and Construction

1. In general, deeper oil wells encounter greater pressures and temperatures, are more complex, and pose greater risk of a loss of well control, or a "blowout." The proposed Zanahoria 1 well would be at total depth of 6,800 m, (22,000 feet), or about 20% deeper than the failed Macondo well in the U.S. Gulf of Mexico drilled by the Deepwater Horizon MODU (which was at 5,596 m, or 18,360 feet total depth, with a reservoir pressure exceeding 13,000 psi). The Cebolla 1 prospect is at 6,370 m, or 20,000 feet total depth. Thus, pressures, temperatures, and risks encountered in the deep Canary Island wells could be comparable to, or significantly greater than, those of the Macondo well that failed catastrophically.

2. The EIS does not present evidence that a robust well integrity Risk Assessment for specific well designs has been conducted, or that such will be conducted prior to drilling, as required by *Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations* (EU, 2013). The well integrity Risk Assessments should focus particular attention on the expected difference between pore pressure and fracture gradient of surrounding rock strata. The "Risk Analysis" briefly mentioned in the ING IMPL annexes fore each well pertains only to the statistical risk of failing to locate an oil reservoir, not the risk of a blowout. And the well designs in the annexes present alternative designs for each well cite, making it impossible to assess actual risk posed by specific wells.

3. The EIS does not discuss predictions as to whether the Canaries drill sites are hydrate or hydrogen sulfide (H2S) prone areas, and plan mitigations accordingly (e.g. methanol injection in BOP to reduce hydrate formation, etc.).

4. The EIS does not discuss in detail the detection and management of *shallow hazards* that may be encountered during drilling.

5. The EIS does not provide sufficient detail regarding expected reservoir characteristics. The geology and lithology of the proposed well sites is presented, but not safety-critical issues such as reservoir pressures. Computer simulations and hydraulic modeling can accurately predict the down-hole pressures that may be encountered. The EIS needs to discuss the predicted *Maximum Anticipated Surface Pressure* (MASP) for the wells, and *Maximum Anticipated Wellhead Pressures* (MAWHP). In particular, there is

no predicted formation fluid pressure identified, and no discussion of well casing strength and design specifications needed for pressure containment at depth. The annexes describing each well mention, in the discussion of muds, "mud weights are estimated according to the design and currently estimated formation pressures." However, the estimated formation pressures are not reported.

6. The EIS does not provide sufficient detail regarding well design. General well design for each prospect is discussed in the ING IMPL annexes, with alternatives proposed for each well, but these need further detail, as required by the DGQEA letter, and by the *2013 EU Drilling Directive* (EU, 2013). The annexes report that a 7" casing liner will be used in the bottom of the wells, "contingent on the integrity of the well." But, it fails to discuss the process for verifying the integrity of the well, and for reaching decisions regarding the casing liner. The approved well-specific design must, for instance, specify number and type of centralizers intended for use to center the casings to ensure cement integrity (to minimize channeling), the specific float valves to be used, the cement procedure (see below), the temporary abandonment process (see below), kick detection procedures (see below), and the procedure and safety protocols for displacement of the muds prior to abandonment.

7. The EIS does not discuss, nor commit to comply with, API Standard 65–Part 2, *Isolating Potential Flow Zones During Well Construction*; Second Edition, December 2010, as the company is required to do in its U.S. offshore operations, and as implied in the *2013 EU Drilling Directive* (EU, 2013).

8. The EIS does not detail the real-time management and monitoring regime during drilling, and a detailed, site-specific well control pressure-testing program, as the company is required to do in its U.S. offshore operations, and required by the *2013 EU Drilling Directive* (EU, 2013).

9. The EIS does not discuss the need for a third-party professional engineer to certify that the well design and construction is appropriate to the expected and encountered conditions in the well bore, and to verify the placement of the barriers during well completion and abandonment and that the casing hanger latching (lockdown) mechanism is in place when casings are installed.

10. The EIS does not detail the specific mud/gas separation (MGS) and overboard diverter systems that each drilling rig will have, as the rigs have yet to be identified. These are safety-critical systems.

11. The EIS does not include detailed documentation and schematics for all control systems on all safety-critical equipment.

C. Drilling Rigs

1. The EIS does not propose a specific alternative for the wells to be drilled or the rigs that would be used to drill the prospects. This needs to be decided prior to further review and approval.

2. The EIS does not provide sufficient detail regarding rig instrumentation and control systems. This instrumentation must account for possibility of simultaneous multiple system failures, and to retain operability of rig, well, BOP, and riser, and must be *Best Available Technology*. Rigs must have tested and proven capability to divert hydrocarbon flow overboard, and an automated system to activate gas diversion if needed.

3. The EIS does not detail the electrical generator safety systems on the drilling rigs. Backup electrical generators must be proven operable, and located such that they can be auto started safely in a blowout, fire, explosion scenario on drill floor or main engine room. Proper location of fresh air intakes should be identified. In particular, there needs to be discussion of the overspeed shutdown devices for the generators to cut off fuel and air in an overspeed event. This is necessary to prevent ignition during a gas kick. In the presence of a hydrocarbon gas cloud, the generators will ingest hydrocarbons and air, and accelerate to dangerous levels, creating the danger of ignition. This is suspected to be the source of ignition of the combustible gas cloud surrounding the *Deepwater Horizon* rig, causing the explosion and subsequent disaster.

4. The EIS does not provide detail on the *Integrated Alarm and Control System* (IACS) on the drilling rigs, *Combustible Gas Detectors* (CGDs), or a schedule for regular inspection and testing of the alarms. This should include a discussion of specific procedures established for any inhibition of alarms, and the approval and notification processes for such.

5. The EIS does not provide detail regarding the fire suppression systems on the rigs, or fire training and drills for crew.

6. The EIS does not discuss the command authority on the drilling rigs, which must be clearly established, unambiguous, and maintained. Roles of Repsol management, the vessel captain, Offshore Installation Manager (OIM), and subcontractors all need further detail, so that there is no confusion regarding who is responsible for what decisions during an emergency, including activating the EDS, abandon ship, and so on.

D. Drilling Muds

1. The EIS does not provide sufficient detail regarding drilling mud specifications, as required by the DGQEA letter. These include mud

formulation, application and control, mud additives (e.g. particle size of barite to be used), compressibility, and pressure-volume-temperature (PVT) analysis, specifically for muds to be used in HPHT wells. This should include a discussion of control of impurities, such as clay, carbonate, iron, etc., that may compromise mud integrity or function.

2. Drilling mud engineering is a critical element of a safe drilling program, particularly for deepwater HPHT wells. Properties of the drilling muds that are not elaborated for the proposed Repsol deepwater wells include plastic viscosity, yield stress and gels, compressibility, gas solubility, stability to contaminants and aging, and weighting. As stipulated in the DGQEA letter, all such specifications need to be provided, but the EIS only mentions weights of muds. Exact calibration of mud (weight, viscosity, etc.) must be identified that will maintain well control. If the mud weight is too high, the surrounding formation may fracture, leading to a loss return event and potentially an influx of hydrocarbons into the well. If the mud weight is too low, then the well is in an underbalanced condition, also conducive to flow into the well. The annexes present various mud weights (e.g. 8 ppg – 10 ppg, etc.), but no justification as to how these mud weights were derived. In fact, it is questionable that the maximum mud weight discussed for the deepest wells (10.7 ppg) is sufficient. By contrast, the maximum mud weight used in the shallower Macondo well in the Gulf of Mexico was at least 14.3 ppg.

3. The EIS does not propose the specific type of drilling mud to be used. It states that choices of muds for the riser (closed) phase of drilling continue to be analyzed, and two distinct alternatives are in consideration: *Water Based Mud* (WBM) or *Synthetic Based Mud* (SBM). Oil-based muds are generally more stable at the high temperatures in HPHT wells, but they more prone to gas dissolution, making kicks more difficult to detect. The pros and cons of each type of drilling mud, in relation to well specifics, need to be discussed. Section 3.4 states that: "The final selection of drilling muds used in closed-system phases will depend on technical and safety requirements of the well, related to the drilling survey characteristics." This needs to be decided and detailed in the EIS.

4. The EIS does not detail the quality control process for mud formulation and pumping. Pumping sequence is important to ensue that the cement is not contaminated by the spacer fluid or mud. Data logging must be conducted in a methodical manner, and the procedure needs to be detailed in the EIS. All computer software programs for muds need to be identified in the EIS.

5. The EIS does not discuss the formulation of the "lost circulation pills" that would be pumped into the well in response to a lost circulation event.

6. The EIS does not select a disposal method for drilling muds and cuttings. The most appropriate option in a sensitive marine area is to not permit the

discharge of any drill cuttings and muds (including WBMs) to the sea, but rather to collect and transfer all such wastes to a shoreside treatment facility.

E. Cementing

1. The EIS does not meet the requirements in the DGQEA letter or other Directives regarding details of the cement and cementing procedures to be used. It is well known that cementing problems, including the annulus between casings and the surrounding rock formation and the cement plugs in the well bore, constitute one of most significant risk factors for blowouts. Particularly in HPHT wells, cement formulation and application is an extremely important, safety-critical aspect.

2. The EIS does not reflect or commit the project to comply with the enhanced cementing requirements in the new offshore drilling safety rule in the U.S. (BSEE, 2012), with which Repsol must comply in its U.S. offshore operations.

3. The EIS does not provide detailed cement specifications other than it will be *Class G w/ additives, depending on surrounding temperatures*. Clearly, much more detail is needed on proposed cement formulation, including specific additives anticipated (silica, hematite, fluid loss additives, dispersants, retarders, anti-gas migrating agents, defoamers, latex, etc.), density, foamed vs. un-foamed cements, weights, predicted slurry stability at high pressure and temperature, setting time, and strength.

4. The EIS does not specify that the cement will be dual certified by API-10A and ISO 9001-2000.

5. The EIS does not provide a rationale for why Class G cement was selected instead of Class H cement. In fact, Class G is reported to be effective at preventing loss of circulation at temperatures only up to 120 C, and as the expected well temperatures reported in the Canaries EIS are 150 C or more, the choice of Class G cement is questionable. Class H is known to be effective up to 230 C, and to have additional advantages of low viscosity, low fluid loss (to minimize cracks and gas migration), and low permeability for zonal isolation and low gas migration (LaFarge, 2013).

6. The EIS does not discuss the effects of pressure and temperature on cement formulation, in particular the foam quality (% gas in the cement foam).

7. The EIS does not identify a rigorous process for deciding and confirming cement specifications, and the testing procedure for cement slurry formulation, including where and at what intervals the cement slurry samples will be flown from the rig to onshore laboratories for testing prior to application.

8. The EIS does not detail the Quality Control process for cement makeup on the rig. This must include the training and experience of rig crew and cement personnel or contractors.

9. The EIS does not discuss the computer software and cement simulation programs that will be used to predict outcome of the cement job based on configuration of wellbore and casings, the number of centralizers that will be used, rate of cement pumping, weight and viscosity of cement relative to mud displaced, and expected time that will be necessary for the cement to set. The EIS discussed the amount of cement and general class of cement available, but nothing more.

10. The EIS does not discuss the relationship between RIPSA and its cement subcontractor, the experience of the contractor, and how decisions will be made before and during cementing. It should be noted that test results on the cement slurry used on the Macondo well showed that it would likely fail, yet no one onshore or on the rig acted on this information.

11. The EIS does not detail the acoustic cement bond log, or cement evaluation log, that would be conducted to verify the integrity of the cement bond with the casing.

F. Pressure testing

1. One conclusion reached regarding the *Deepwater Horizon* blowout is that: "The failure to properly conduct and interpret the negative-pressure test was a major contributing factor to the blowout" (OSC, 2011).

2. The EIS does not detail the pressure tests that will be performed prior to mud displacement and abandonment. In particular, the negative pressure test is a critical procedure to test integrity of cemented final casing string or liner, where mud is removed from the well bore, replaced with less dense seawater, to determine if pressure increases in well bore that might indicate a dangerous flow of hydrocarbons into the well. This procedure needs to be discussed in detail.

3. The EIS does not commit the company to comply with new, enhanced pressure testing requirements in the U.S. (BSEE, 2012), with which the company must comply in its U.S. offshore operations.

4. The EIS does not discuss the process by which the pressure tests will be *analyzed and interpreted*. Critically important is that the negative pressure test be interpreted accurately (it was not on the Macondo well), in order to ensure the integrity of bottom cement and the well.

5. The EIS does not discuss the *training and experience* of the drill crew in the pressure testing procedures. And it does not commit to provide for an Independent Professional Engineer to verify that the pressure tests confirm well integrity.

6. The EIS does not establish the command chain for conducting and interpreting the negative pressure test, as well as interpreting or responding to any anomalies encountered.

G. Kick Detection

1. The EIS does not discuss the specific procedure and guidelines that will be used to monitor kicks from the well. The EIS needs to detail a kick monitoring system (e.g. Kick Alert Status), with successive levels of alert, and procedures for responding to such alerts. Early detection of flow is critical. It should be noted that the influx of hydrocarbons into the Macondo well on the *Deepwater Horizon* was not detected until 50 minutes after flow had started, rendering well control more difficult.

2. The EIS does not provide sufficient detail regarding the number and locations of the *Combustible Gas Detectors* (CGDs) and monitoring systems on the rigs. It needs to detail the gas detection alarm system, mud volume alarms, H2S detectors, and gas diverter controls. The system for integrating all well flow data should be discussed. As well, a regular alarm testing protocol should be established.

3. The EIS does not detail the gas diverter systems on the rigs (as the specific rigs are not yet identified). As well, procedures need to be detailed for deciding when to divert fluids into the mud-gas separator (MGS), which can only accommodate a limited volume of fluids, or overboard to the downwind side of the rig.

4. The EIS does not discuss training and experience of drill crews to monitor well pressures during completion and abandonment. This should include emergency response training of drill floor crew, drills and simulations of emergency situations.

H. Blowout Preventers

1. The EIS does not recognize the inherent limitations of Blowout Preventers. A Blowout Preventer (BOP) is a critical system for subsea wellhead blowout control, but the EIS should clearly recognize that a BOP is not a failsafe mechanism for sealing a well blowout. Numerous studies have documented the limited effectiveness of BOPs in sealing subsea well blowouts (e.g., NAE, 2011; West Engineering Services 2002, 2004), but the EIS does not cite any of these. Some studies report a BOP failure rate up to 45%. The residual risk

imposed by this inherent failure rate should be honestly discussed in the EIS, so that the public and government do not develop a false sense of security by the installation of a BOP on the seabed wellheads.

2. The EIS does not detail the emergency procedures and decision process for activating the BOPs.

3. The EIS does not commit to *Best Environmental Practice* or *Best Available Technology* for BOPs on the project wells. The EIS states (CH 4, p. 77) that the company will "take into consideration the recommendations of API Standard 53" (*Blowout Prevention Equipment Systems for Drilling Wells*), but does not commit to *comply* with provisions of API Standard 53. The EIS gives little further elaboration on the BOPs, other than the general working pressures. API Standard 53 consists primarily of *required actions*, not optional *recommendations*. And, Repsol is required to comply with API 53 in its U.S. offshore operations, as this standard is incorporated by reference in the new U.S. Drilling Safety Rule (BSEE, 2012). As well, this requirement is implied in *Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations* (EU, 2013).

4. Even strict compliance with API 53 is not considered *Best Environmental Practice* of *Best Available Technology,* and meeting this standard alone may not be sufficient to ensure full function of the BOPs under all possible conditions that may be encountered in Canary Island wells. For instance, for some provisions, API 53 uses "should" rather than "shall."

5. The EIS does not state the Class (the total number of ram and annular preventers) of the BOPs to be used (e.g., Class 6-A2-R4 = 2 annular and 4 ram preventers). API 53 requires at least Class 5 or higher for Subsea BOPs, but the EIS is silent on specifics of the project's BOPs, including the manufacturer and Class.

6. The EIS does not cite a *Maximum Anticipated Well Head Pressure* (MAWHP) for the Canary wells. In section 7 of API 53 "Subsea BOPs," BOP must have as a minimum a *Rated Working Pressure* (RWP) equal to MAWHP to be encountered.

7. The EIS does not discuss or commit to the requirement in API 53 that a Risk Assessment to be performed by the operator/owner for the BOPs, to identify all drilling operations, testing, kick scenarios, well control responses, potential for riser failure, and unplanned disconnects.

8. The EIS does not stipulate the precise design and type of BOPs intended for use in the project. API 53 requires only one set of BSRs capable of shearing and sealing the well pipe and tubing in subsea BOPs for anchored rigs (such

as one of the EIS alternatives provides), but only after confirmation by a Risk Assessment.

9. The EIS does not commit to report BOP problems or malfunctions to government authorities, in addition to the manufacturer.

10. The EIS does not commit the operating company to comply with the API 53 *testing and maintenance schedule* for BOPs prior to deployment, and in other circumstances. It provides no other testing schedule for the BOPs, thus it is not clear what testing will be conducted on the project's BOPs. BOPs should be tested under real world pressures, and to confirm that the Blind Shear Rams (BSRs) will be able to shear all pipe and pipe tools in real-world flow conditions with rocks, sand, cement, and even drill pipe joints in the BOP. The BOPs should also undergo inspection and function verification after particular drilling events, such as after stripping tool joints.

11. The EIS does not require independent certification of BOP design and function. Third party verification by a professional engineer is *Best Environmental Practice*, and is necessary to verify proper function testing of the BOP, including all BSRs, ram preventers, that the BOP meets manufacturer design specifications, to assess any modifications made, that it is compatible with the specific drilling equipment to be used (e.g. BSR compatible with all drill pipes to be used), has not been compromised or damaged during previous service, and compatible to all conditions potentially encountered. This requirement is implied in the *2013 EU Drilling Directive* (EU, 2013).

12. The EIS does not commit to independent third party verification of the training, experience, and competency of the personnel who would test, install, and operate the BOP systems. Procedures should be presented that confirm the crew understands exactly how to respond to anomalies in the BOP system. The management system (see below) should be sufficient to address all such anomalies.

13. API 53 7.6.4 states: "Maintenance and testing shall be performed or supervised by a competent person(s)," but does not require specific minimum qualifications or experience. This should be discussed in the EIS, as a BEP standard.

14. The EIS does not discuss rig-specific procedures for installation, operation, and maintenance of BOPs for specific well and environmental conditions, as required in API 53 7.6.9.4.

15. The EIS does not detail the specifics of the *Emergency Disconnect System* (EDS). An *Emergency Disconnect System* (EDS) on the BOP is required for

Dynamically Positioned rigs (API 53). Details and functions of the EDS are specific to each rig, drilling equipment, and location, and should be discussed.

16. The EIS does not provide sufficient detail on the BOP secondary activation systems: ROV intervention; the "deadman" system, in event of loss of hydraulic supply or signal transmission from rig; and the "autoshear" system, to activate BOP if disconnect of the *Lower Marine Riser Package* (LMRP); as required by API 53.

17. The EIS does not commit to incorporating acoustic activation capability on the BOPs. This is an optional secondary control system in API 53, but for HPHT wells in *High Consequence Areas* such as the Canary Islands, where BAT should be the required, acoustic triggers on BOPs should be required as an additional backup BOP activation mechanism.

18. The EIS does not detail a continuous diagnostic monitoring and electronic log system for the BOPs, which needs to monitor electronics, flow inside the BOP, ram position, pipe and tool joint position in the BOP, and fault indicators for conditions inside the BOP. A robust operator training regime for emergency BOP operation must be identified, with established minimum qualifications for crew that would operate BOP.

19. The EIS does not commit that a *Remotely Operated Vehicle* (ROV) and trained crew will be on standby on the drilling rig at all times, and will be periodically tested to demonstrate competence in activating the BOP, including the ability to close all shear and pipe rams, close the choke and kill valves, and detach the LMRP.

20. The EIS does not discuss the need for BOP and well function alarms to automatically default to close the well (activation of BSRs, EDS, general alarm, etc.), if specific alarms trigger but are not addressed in timely manner.

<u>I. Well Abandonment</u>

1. This EIS does not provide sufficient detail regarding the safety-critical procedures the operator will use in well completion and abandonment, as required in the *2013 EU Drilling Directive* (EU, 2013). Abandonment is mentioned in the EIS annexes for each drilling prospect, but in far too general a manner.

2. The EIS does not identify the specific process that will be followed in well abandonment, either temporary or permanent, beyond just that it will be *consistent with Repsol internal procedures and NORSOK D10*. Particularly important is the need to identify the precise step-by-step procedures that will be used to displace kill-weight drilling fluid from well bore, the sequence for placing the plugs and mechanical barriers, tests the operator will run to

ensure integrity of independent barriers, BOP procedures it will use while displacing drilling fluids, procedures the operator will use to monitor volumes and rates of fluids entering and exiting the wellbore, and the company and governmental approval and monitoring process prior to and during abandonment.

3. The EIS identifies the proposed location of the cement plugs in the wells for abandonment, but does not provide sufficient rationale for these decisions.

4. The EIS does not identify the management process that will be used for any alterations in the planned abandonment procedure, including a rigorous Management of Change (MOC) process for altering proposed procedures. This is required in *Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations* (EU, 2013).

5. The EIS does not commit to engage an *Independent Well Control Expert /Engineer* to certify and approve all well abandonment procedures.

J. Well Capping & Blowout Contingency Plan

1. The EIS does not present a rigorous well control plan, *Blowout Contingency Plan* (BOCP), a relief well plan, and secured contracts to provide these services.

2. The EIS states that a loss of well control response plan is "in development," but a detailed plan for responding to loss of well control event must be developed and approved prior to issuing permission to drill, as required in the *2013 EU Drilling Directive* (EU, 2013).

3. The BOCP, which is "in development," must detail all technologies to be used, and verify that tests in expected conditions (at depth, temperature, and pressures expected at the seabed) have demonstrated the effectiveness of the well control response technologies. These should include a *containment dome* or *top hat* for initial response, a discussion of the pros and cons and methodologies for attempting a *top kill* of a blowout, a *capping stack* specifically fitted to the BOP to be employed, and an adequate riser system and surface support vessels to collect oil from a blowout. The BOCP needs to identify communications and logistics for deploying all equipment and support vessels necessary in a blowout response. This should include where the equipment will be physically located on stand-by, and how quickly it could be deployed to the various drilling sites.

4. The EIS does not identify the contractors that the company has engaged to provide blowout control response, as well as the contractor's resources and experience. New well containment and capping consortia in the U.S. include the *Marine Well Containment Company* (MWCC), in which Repsol E&P USA *is*

not a member, and the *Helix Well Containment Group* (HWCG), in which Repsol E&P USA *is* a member. Yet the EIS does not discuss any potential involvement of HWCG in the Canaries drilling project. OSRL is developing a deepwater well control system, but the EIS does not discuss this, or any agreements or contracts it has entered into for such emergency well capping services. The EIS mentions an association with *Well Control International,* but does not elaborate.

5. The EIS does not provide a specific plan, or discuss a contract, for a rig to drill a *relief well* to perform a permanent bottom-kill of a blowout. This needs to identify what rig would be used to drill a relief well, where it will be located during the Canaries drilling project, response time, and capability to drill the relief well to the depths of the various proposed wells.

K. Management

1. Failure of management is thought to be a primary cause of the *Deepwater Horizon* disaster, as with many other offshore drilling incidents. The *U.S. Oil Spill Commission* concluded as follows: "The [Macondo] well blew out because a number of separate risk factors, oversights, and outright mistakes combined to overwhelm the safeguards meant to prevent just such an event from happening. But most of the mistakes can be traced back to a single overarching failure – a failure of management." And in addition: "Better management of decision making processes within BP and other companies, and effective training of key engineering and rig personnel would have prevented the Macondo incident. BP and other operators must have effective systems in place for integrating the various corporate cultures, internal procedures, and decision making protocols of the many different contractors involved in drilling a deep water well." (OSC, 2011).

2. The EIS does not provide adequate evidence that a *Best Environmental Practice Safety Case* is established for the project, as suggested, for instance, by the *International Association of Drilling Contractors* (IADC *Health, Safety, and Environmental Case Guidelines for Mobile Offshore Drilling Units*).

3. The EIS does not present a detailed discussion of safety management culture in the operating company, RIPSA. This is required by *Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations* (EU, 2013). This safety management discussion should detail how the company instills attitudes and procedures in the company that ensure the highest level of safety possible. The safety culture of RIPSA must embody the specific leadership safety values of the organization, personnel accountability, hazards identification and resolution, work processes to maintain safety, continuous learning systems, an open environment for raising safety concerns, effective communication, and a questioning attitude.

4. The EIS does not discuss nor demonstrate that the operating company (RIPSA) is a *High Reliability Organization* (HRO) such as those that design, test, operate, and maintain nuclear power plants, air traffic control systems, certain military operations and facilities, and space flight.

5. The EIS does not discuss various international frameworks for managing systemic risks in complex systems, such as the U.S. Department of Defense *Standard Practice for System Safety* (DOD, 2000).

6. The EIS does not identify all subcontractors to be used, and how they will be managed. In a drilling a complex deepwater prospect, it is necessary to effectively manage several drilling subcontractors, service companies, and consultants, and staff. In drilling the Macondo well in the Gulf of Mexico, BP employed at least eight (8) subcontracting companies for various components of the project. The relationship and communication between all corporate entities involved in a complex deepwater drilling operation is a safety-critical issue. The EIS should clarify this relationship, and which personnel have stop-work authority, and how and when this may be imposed.

7. The EIS does not identify an integrated assessment program to maintain the critical *margin of safety* in drilling, particularly for complex deepwater, HPHT wells.

8. The EIS does not stipulate that an *Independent Well Control Expert* (IWCE), will be available and review the drilling procedures at all times during drilling, as well as a procedure for obtaining peer review and second opinions on various safety-critical decisions made before and during drilling. Such a system exists in the U.K., is required in the new U.S. offshore Drilling Safety Rule (BSEE, 2012), and implied by the *2013 EU Drilling Directive* (EU, 2013). The independent third party expert should be a Registered Professional Engineer, whose qualifications are presented to and approved by government.

9. The EIS does not discuss key personnel training and expertise, and a standardized system to verify that all personnel are competent to manage risks and complexities of deepwater drilling. This is required by the new offshore drilling safety rule in the U.S. (BSEE, 2012), with which Repsol is required to comply in its U.S. offshore operations. As well, this is required by the *2013 EU Drilling Directive*. This training should include key personnel both on the rigs and onshore.

10. The EIS does not discuss a system for incorporating "precursor events" and near-miss, potential casualty experiences into real-time management. This must include a system for oversight and reporting of human factors in near-miss events. To the extent that legal liability is an impediment to a near-miss casualty reporting system, this should be addresses and mitigated.

11. The EIS does not identify, as a risk mitigation measure, an anonymous safety reporting capability ("whistleblower" provision), incentives and protections for personnel using such a system, and how each such report will be investigated. This is required by *Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations* (EU, 2013).

12. The EIS does not identify emergency response training and drills and simulations of blowouts.

13. The EIS does not detail the shoreside management system that will be in place to provide real-time safety oversight of the drilling projects.

14. The EIS does not commit the operating company to establish a *Safety and Environmental Management System* (SEMS), as is now required in U.S. regulation (30 CFR 250 (*Federal Register*, Vol. 75, No. 199, Oct. 15, 2010). This is also required in *Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations* (EU, 2013). In this regard, the EIS should detail the company's safety management structure, technical expertise, deepwater experience, analytical methodology to assess the performance of all safety system in event of multiple failures, and its overall *safety culture*. SEMS is a goal-oriented, performance based *Safety Case* approach, rather than the traditional prescriptive approach. It requires operators, contractors, and service companies to document their safety approach; work together to achieve safe drilling outcomes; formalize risk management procedures and responsibilities of all parties; establish clear communication procedures; establish a *Management of Change* (MOC) process; provide an independent assessment of well design, drilling, and completion; and a procedure to manage and incorporate evolving technologies. The *U.S. National Academy of Engineering* recommends a hybrid of prescriptive and performance based management regimes, and this should be discussed in the EIS.

15. The EIS does not commit the company to comply with API RP 75: *Development of a Safety and Environmental Management Program for Offshore Operations and Facilities.* This is a BEP standard.

16. The EIS does not identify the operational relationship between all project owners - RIPSA, Woodside Energy Iberia, S.A.; and RWE dea AG – the drilling rig owners, and subcontractors, particularly with regard to decision-making procedures and authorities for safety-critical issues.

17. The EIS does not discuss the company's *Management of Change* (MOC) process, for real-time management of changes made in well design and completion, as required in the March 4, 2013 *Drilling Directive of the European Parliament and Council* (EU, 2013).

18. The EIS does not detail a Preventive Maintenance (PM) program, and the rig-specific inspection program that would be used.

19. The EIS does not discuss the precise relationship the company will have with government regulators during the project, including frequency of inspection, approval processes, etc.

20. The EIS does not discuss any relationship with the new American Petroleum Institute's *Center for Offshore Safety* (COS) in the U.S., and as Repsol E&P USA is active in U.S. offshore leasing, both in the Gulf of Mexico and Arctic Alaska, the company should be an active participant in the API COS, and should discuss such in the EIS. As well, the EIS does not discuss relationships with other industry peer associations, such as the *International Association of Drilling Contractors* (IADC), the *International Petroleum Industry Environmental Conservation Association* (IPIECA), the *European Union Offshore Oil and Gas Authorities Group* (EUOAG), and others as appropriate.

IV. **Oil Spill Contingency Plan (PICCMA)**

A. General

1. The *Oil Spill Contingency Plan* (OSCP, or PICCMA) is still listed as "preliminary" in the EIS. And as presented, it is unsatisfactory in many respects. It is evidently a general plan used by Repsol for other projects, with standard notification procedures, management organization, and so on. As the EIS anticipates the start of drilling in second half of 2014, the OSCP needs to be fully detailed and approved by this point in time.

2. The OSCP does not commit the company to a *Response Planning Standard* that would impose a performance standard on the response capability (e.g. ability to collect 300,000 bbls in 3 days). This is also called an *Effective Daily Recovery* (EDRC) rate, for all recovery equipment available, and needs to be identified in the OSCP.

3. The OSCP does not detail dispersant protocols, in-situ burning protocols, equipment specifications and limitations, and spill drills and training (see below).

4. The OSCP lists equipment available, but without sufficient specifications. Equipment listed as on hand to respond to a Tier I spill does not provide detail to ascertain effectiveness, e.g. dimensions of containment booms, capacity of skimmers, etc. The EIS does not list equipment or specifications available to SASEMAR for a Tier II response, and the discussion of a Tier III (major spill) response, which will rely on *Oil Spill Response Limited* (OSRL), does not provide sufficient equipment specifications.

5. The OSCP provides little detail regarding spill detection and tracking procedures, particularly subsurface plume tracking, or spill tracking during adverse weather conditions (e.g., at night, low visibility, etc.).

6. The OSCP does not provide detail regarding response training and spill drills.

7. The OSCP does not provide a detailed oiled *Wildlife Response Plan* (WRP). The *Wildlife Response Plan* must include details regarding wildlife response objectives, wildlife reconnaissance during a spill, hazing of wildlife away from projected spill paths, field stabilization, recovery, treatment, and staffing and equipment of treatment facilities.

B. Worst Case Blowout Scenario

1. The EIS concludes that probability of a major blowout is 1.99 x 10 (-5), or 1/50,251, and that such an event is therefor considered "highly unlikely." This sort of probabilistic prediction is misleading, and can lead to a false sense of risk management, indeed even to a dangerous complacency and lack of vigilance. In fact, a catastrophic failure in complex industrial systems, such as a deepwater well blowout, can occur from a series of simple human errors and equipment malfunction. The EIS must anticipate and discuss such.

2. Table 1.3 in Annex 12.2, regarding historic catastrophic blowouts, cites an inaccurate duration for the *Deepwater Horizon* blowout of just 77 days, while the actual duration was 87 days (April 20 – July 15).

3. The "worst case" blowout scenario considered in the EIS is only 1,000 bbls/day/30 days, which is unrealistically small. The substantiation for selecting this flow rate and duration is extremely weak. For instance, the blowout duration of 30 days is derived from Brazilian legislation (CONAMA Resolution No. 398 Brazil), and flow rate is derived from an internal Repsol procedure, with no further elaboration. This is unacceptable.

4. To further support its modest "worst case" blowout scenario, the EIS argues that reservoir locations are precisely known, geology and temperatures are expected to be within the limits of a "normal well;" and that the formation fluids are expected to be mostly crude oil, with very little natural gas. This is subjective, and overly optimistic.

5. By comparison, the initial flow rate estimated from the 2010 *Deepwater Horizon* Macondo blowout was 100,000 bbls/day, declining over time (as reservoir pressure declined) to an estimated average of 62,000 bbls/day, for a total duration of 87 days, giving a total spill volume of 4.9 million bbls (of which 800,000 bbls was reportedly collected at the wellhead).

6. Also by comparison, in 2011 the U.S. government projected a worst case blowout scenario for Shell Oil's offshore drilling in the Chukchi Sea (Arctic Ocean) to begin at 61,000 bbls/day, decline to about 19,000 bbls/day after 30 days, for a duration of 39 days, giving a total release of 1.38 million bbls. The drilling prospects modeled in the Chukchi Sea are in only 50 m water depth, and a total well depth of only about 3,100 m. It should be noted that the company, Shell Oil, had initially (April 2010) modeled a worst case discharge for the Chukchi Sea project of only 5,500 bbls/day/30 days, for a total discharge of 165,000 bbls. Thus, the U.S. government's worst case discharge modeled for the drilling project is over 8 times larger than that initially modeled by the operating company. After the 2010 *Deepwater Horizon* spill, Shell revised (March 2011) its worst case discharge blowout scenario upward to 25,000 bbls/day/30days, for a total discharge of 750,000 bbls. Some of the proposed Canaries wells are more than twice the depth of the planned Chukchi Sea wells, and will present considerably higher pressures and potential blowout flow rates.

7. A more realistic metric for deriving a worst case blowout scenario would be to simply use averages from actual major offshore blowouts. The average duration of the catastrophic blowouts listed in Table 1.3 Annex 12.2 (which include several shallow water blowouts), was 73 days, and the average spill volume was about 1 million bbls. These averages provide a more appropriate base assumption to use as a worst case scenario in the Canaries drilling project.

8. Given that the depth, pressures, and drilling complexities likely to be encountered in the deepwater Canary wells may equal or exceed those for the Macondo well, a more reasonable worst case blowout scenario for the Canary drilling project would be 30,000 bbls/day/60 days duration, or 1.8 million bbls total discharge. This recommended worst case blowout is 60 times larger than the worst case scenario presented in the EIS.

9. This larger worst case blowout scenario, while hopefully improbable, is certainly possible. Sixty (60) days is a reasonable estimate of the time it would take to complete a relief well at the deepest well depth (e.g. at the Zanahoria and Cebolla prospects). It should be noted that it took BP 12 days after the *Deepwater Horizon* explosion just to begin drilling a relief well (on May 2), and the relief well was not completed until September 19, more than 4.5 months (137 days) later. The Macondo well was shallower than either of the two of the Canaries prospects mentioned above. Such a potential relief well duration should be anticipated in the Canaries EIS.

10. The EIS does not provide a discussion of the causes or specific responses to historic worst-case offshore blowouts, which indicates a lack of consideration for lessons learned. This is also required in the *2013 EU Drilling Directive* (EU, 2013).

11. Use of the larger, more reasonable, worst case blowout size (1.8 million bbls) will alter all aspects of the spill model presented in the EIS (see below), dramatically enlarging the area affected, amount of surface oil, and the amount of shoreline oiling. As well, this will greatly increase the expected environmental impacts from a spill.

12. The OSCP does not discuss methods that would be used to quantitatively estimate flow rate from a deepwater blowout.

C. Spill Model

1. The *Applied Science Associates* (ASA) spill trajectory model conducted for the EIS projected the spill simulation to only 45 days, which is insufficient. Even if the source (blowout) continued for only 30 days (as projected in the EIS), oil would certainly persist and spread in the marine environment far longer than a total of 45 days. This is clearly demonstrated by the mass balance graphs in the simulation itself, which show that in virtually all cases, from 50%-70% of the total oil discharge volume would remain in the water column up to and beyond the end of the 45-day simulation period. As well, this is evident in the abrupt demarcation in the spill trajectories as oil reaches southward to 26 degrees N Latitude (apparently at 45 days). Accordingly, the simulation should run for at least 100 days (or longer, based on projected dispersion and degradation rates).

2. It is clear that the larger volume worst case scenario (1.8 million bbls, or 60 times larger) should be modeled. In the expanded simulation, oil would transport farther southward toward Mauritania, Senegal, and Cape Verde, southwestward into the equatorial Atlantic, and would certainly contaminate a much larger region than the EIS currently discusses. All of the ASA spill model findings will be significantly altered when using the more reasonable, and much larger, worst case discharge proposed here.

3. The ASA spill model projections for dispersion, evaporation, and degradation of the modeled blowout are from 80% - 99% of total spill volume. Such rates are overly optimistic, particularly given the rates reported in the *Deepwater Horizon* spill. The U.S. government oil balance estimate from the *Deepwater Horizon* spill was that 25% evaporated or dissolved, 16% naturally dispersed, thus less than half the amount predicted in the ASA spill model for the Canaries project. The U.S. government estimated that 26% of the total oil release volume for the *Deepwater Horizon* remained ("residual") in water, sediments, or on shorelines (USGS, 2010). Similar mass balance assumptions should be used in the Repsol EIS.

4. The OSCP does not discuss the emulsification rate for spilled oil, which would expand the volume of oil/water mixture for a response by a factor of about

1.5. Thus, a 1.8 million bbls oil discharge would expand by emulsification to approximately 2.7 million bbls.

D. Mechanical Recovery

1. The OSCP does not recognize and report that only a small fraction of an open ocean spill will be recovered, regardless of the efficacy of the response plan. Generally, less than 10% is recovered, and often much less. For example, recovery of *Deepwater Horizon* spill was only 3% of total release volume, despite the largest spill response effort in history (with 47,000 response personnel, 7,000 vessels, costing over $14 billion). And recovery rate in the *Exxon Valdez* spill was about 7%.

2. Clearly, and as demonstrated in the ASA spill model itself, much of the oil would simply not be accessible to surface containment and recovery efforts. This will dramatically limit the potential recovery rate from a Canary well blowout.

3. The OSCP does not detail the conditions limiting the effectiveness of various spill response technologies, particularly weather and sea state. The NOGAPS Environmental Conditions study reports that 95^{th} percentile wind speeds across the region range from 25 – 35 knots, maximum winds from 35 – 55 knots, and monthly average wind speeds of approximately 20 knots. Waves generated by such winds, reported in the EIS to be up to 3 m in height, would render mechanical containment and recovery difficult at best, and would severely limit the effectiveness of this response method.

4. The OSCP does not discuss, or meet the requirements on spill response stipulated in *Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations* (EU, 2013) and *Directive 2004/35/CE on Environmental Liability with Regard to the Prevention and Remedying of Environmental Damage* (EU, 2004) [http://eurlex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2004:143:0056:0075:en:PDF]. These Directives include an explicit requirement to discuss the limitations on the effectiveness of spill response.

5. The OSCP does not admit that shoreline cleanup on many of the shoreline habitats on the Canary Islands and the coast of Western Sahara should be expected to be modest, at best.

6. The OSCP does not adequately discuss contamination of nearshore, subtidal habitats during a major spill. Shoreline oil can combine with shoreline sediments, become denser than seawater, and when it transports back offshore, sink to the seabed. This phenomenon has been observed in many offshore spills, including the *Deepwater Horizon* spill where large subsurface

oil mats were formed. The Repsol OSCP must address this phenomenon, particularly with regard to potential response efforts.

E. Dispersants

1. The OSCP does not provide sufficient detail regarding the proposed use of chemical dispersants, which it cites as a principal spill response option. Chemical dispersants can break surface oil slicks into smaller droplets, and transfer, via turbulent mixing, sinking, and physical dispersion, the oil from the surface into the water column, potentially accelerating degradation of the oil. However, this transfers much of the impact of the spill from the surface down into the pelagic zone, yet this issue is not discussed in the EIS.

2. The OSCP does not provide precise parameters, protocols, and limitations for dispersant application. Dispersants are often not effective in particular weather scenarios, for instance, at wind speeds of less than 10 knots when turbulent mixing is limited, or at wind speeds of greater than 20 knots, when there is significant turbulent mixing due to winds, and oil droplet size and distribution is such that the dispersant is less effective. The wind regime across the project area, as reported in the NOGAPS Environmental Conditions Report (see above), would render chemical dispersants ineffective in many spill scenarios, as there should be sufficient natural turbulent mixing at such wind speeds. And the dispersant-to-oil application ratio needs to be identified in the OSCP. Normally, this is 1:20.

3. The OSCP does not provide any discussion of the real-time field testing that would be conducted to determine the potential effectiveness of chemical dispersants prior to approval for use in an actual spill.

4. The OSCP does not provide an adequate discussion of dispersant characteristics or areas where they might be used. Dispersants combined with crude oil can be more toxic than either component alone. This *synergistic toxicity* must be discussed in the EIS. It is important that the Government of Spain not pre-approve use of dispersants, and consider their approval *only* on a case-by-case basis. The dispersant protocol for the project should stipulate that dispersants would not be used in waters shallower than 100 meters depth, or within 10 km of shore, where they could drift over shallow waters and contaminate nearshore habitats. And the dispersant plan should restrict application to only fresh oil, not emulsified or weathered oil.

5. The OSCP does not provide detail regarding the specific chemical dispersant to be considered for use, as required by *Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations* (EU, 2013). A complete characterization of the dispersant must identify all active ingredients, the *Material Safe Data Sheet* (MSDS) for the product, the product's toxicity as tested on indicator

organisms from the Canary Islands region, its effectiveness on local crude oils likely to be encountered, and the quantities available and potential manufacture rates. The OSRL equipment list (to be accessed in a Tier III response), lists stockpiles of 6 different chemical dispersant products on hand: *Corexit 9500, Corexit 9527, Finasol OSR52, Slickgone EW, Slickgone LTSW, and Slickgone NS.* At least one of these – *Corexit 9527* – contains a known carcinogen (2-Butoxyethanol), as well as components with endocrine disrupting effects. The EIS contains no corresponding discussion regarding which of these dispersants would be used, their characteristics, toxicities, or effectiveness on regional crude oils. And the manufacturing capability to produce the particular dispersant to be used should be identified. By comparison, BP used over 1.8 million gallons (7,000 tons) of chemical dispersants in its *Deepwater Horizon* response.

6. The OSCP does not provide any discussion of a program for monitoring the effectiveness of a large-scale dispersant application during a spill, including water sampling beneath the dispersed area, and tracking the dispersed oil plume.

7. The OSCP does not discuss the potential application of dispersants at the seabed wellhead (BOP) during a blowout. This was a significant response methodology used in the *Deepwater Horizon* blowout, and its effectiveness and impact remains controversial. The OSCP needs to discuss this potential in detail.

F. In-Situ Burning

1. The OSCP does not discuss in-situ burning (ISB) as a potential response tool. And it is not clear from the OSRL equipment list, referred to in the EIS, what spill ignition or ISB equipment OSRL has on hand. An ISB plan must identify specific ignition strategies (Heli-torches, gels, etc.), herding agents, fire boom deployment strategies, and specific approaches to be used. It is thus indeterminate how in-situ burning would be considered or managed, particularly for a Tier III response. In a major blowout scenario, ISB will almost certainly be considered as an option for offshore response, and thus the omission of a detailed discussion ISB in the OSCP is unacceptable.

2. However, in many spill scenarios, in-situ burning will not be very effective. For instance, in-situ burning will generally be ineffective at water-in-oil emulsification rates of 30% or more, or on dispersed or weathered oil. And, the difficulties of ignition, maintaining a burn, dealing with residues, personnel safety, and keeping wildlife away from a burn need to be detailed, if in-situ burning is considered a response option. The EIS should discuss the difficulties in dealing with burn residues, and the potential environmental impacts of such residues. The OSCP should reference the OSRL *Offshore In-Situ Burn Operations Field Guide*.

G. Oil Spill Waste

1. The OSCP does not adequately address the potential scale of oiled waste from a major spill. Oiled waste from a spill can be orders of magnitude more voluminous than the amount of spilled oil itself, and can present formidable management issues. This is particularly true for the larger worst case spill scenario that should be modeled, which is 60 times larger than that currently modeled in the EIS.

H. Logistics

1. The OSCP fails to adequately address the enormity of logistic requirements in a large-scale oil spill response. Experience has shown that all large-scale spill responses (e.g. *Exxon Valdez, Deepwater Horizon*, etc.) quickly overwhelm pre-planned logistic capabilities, and local communities. This should be more thoroughly addressed in the OSCP.

I. Transboundary Spill Management

1. The OSCP does not adequately address transboundary spill concerns. As a significant oil release from the proposed Canaries wells would likely flow into international waters and waters within other sovereign territories (e.g. Morocco, Western Sahara, Mauritania), the OSCP needs to pre-establish spill response relationships with other potentially impacted governments. The OSCP in the EIS specifically excludes transboundary applicability (Table 6.2).

2. The EIS does not discuss or incorporate Article 32 of *Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations* (EU, 2013). This Article requires of all member states, *inter alia*, the following: *Where foreseeable transboundary effects of offshore oil and gas accidents risk to affecting third countries, Member States shall, on a reciprocal basis, make information available to the third countries.* Yet the Repsol EIS does not provide evidence that the risks of the proposed Canaries drilling project have been discussed with the Government of Morocco or other potentially affected governments.

J. Impacts

1. While analysis of predicted environmental impacts is beyond the scope of this review, it is evident that the potential for long-term environmental impacts from a major spill is not adequately addressed by the EIS. The literature cited omits some of the most pertinent scientific findings from other spill studies, in particular those conducted on the 2010 *Deepwater Horizon* spill in the Gulf of Mexico and the 1989 *Exxon Valdez* oil spill in Alaska. Government studies on the *Exxon Valdez* spill have documented that today, almost 25 years after the initial spill, there is continued lack of

recovery of most injured species and habitats, and that lingering oil in beach substrates remains toxic. Studies on the effects of the *Deepwater Horizon* spill are particularly relevant in assessing potential impacts of a blowout from the proposed deepwater drilling in the Canary Islands, yet none of these studies were cited or discussed in the EIS.

2. The EIS does not discuss in sufficient detail the potential ecological impacts of underwater hydrocarbon plumes that would arise from a deepwater blowout. These were well documented in *Deepwater Horizon* studies.

3. The EIS does not adequately address the issue of *sublethal impacts* from a major spill, including effects on blood chemistry, physiology, tissue damage, behavior, distribution, feeding, reproduction, genetic impacts, and so on.

4. The EIS focuses more on shoreline impacts over offshore pelagic impacts, even though the spill model demonstrates that most of any blowout will be dispersed in, and impact, the offshore water column.

5. The EIS does not accurately assess the potential *severity* of impacts from a major spill. Of the six impact categories established, offshore consequences of a worst case blowout are predicted to be *serious*, but not *very serious, disastrous, or catastrophic.* Coastal impacts are predicted to be *disastrous*, but only on short sections of coastline, and otherwise ranked as *very serious*. This is clearly inadequate for the more reasonable, and larger worst case blowout scenario that should be modeled, releasing a total of 1.8 million bbls of oil over 60 days.

6. The EIS does not recognize that restoration of environmental injuries after a major marine oil spill is virtually impossible, and this recognition is important in order to fully appreciate the potential environmental impacts of such an event.

7. The EIS *does* recognize the data limitations regarding the environmental impact assessment, which is appropriate.

V. Regulatory oversight

A. General

1. While not within the scope of this report, it is important to briefly mention the critical role that government plays in ensuring safety in offshore oil drilling.

2. The regulatory regime of the U.S. government was clearly ineffective prior to the 2010 *Deepwater Horizon* disaster (event though government regulators had assured the Congress just months before that its oversight of offshore

drilling was adequate). Regulations were largely prescriptive in nature, and had not kept pace with the technology or risks of deepwater drilling, in particular the risks during temporary abandonment procedures. The U.S. government lacked personnel with sufficient training and expertise to enforce regulations, or interpret and act on real-time data during drilling. After the *Deepwater Horizon* disaster, the U.S. government reorganized and strengthened its capabilities in offshore drilling oversight and enforcement.

3. It is not clear that the Government of Spain is as yet in process of transposing the new requirements in *Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations* (EU, 2013). The government should review this policy, and ensure its offshore drilling regulatory regime is in full compliance.

4. The Government of Spain should, at a minimum, adopt into Spanish law the new enhanced offshore drilling safety rule as adopted in the U.S. (BSEE, 2012), as discussed in point III.A.3 above.

5. An enhanced offshore regulatory regime for Spain should require *Safety & Environmental Management Systems* (SEMS) for all offshore operators; establish safety-critical control procedures; establish a quantitative risk analysis system; require compliance with industry *Best Available Technology* (BAT) and *Best Environmental Practice* (BP) standards, such as the API standards; review and improve all existing regulations, codes, and standards to ensure BAT and BEP for all offshore drilling; require *Independent Well Control Engineers* to review and certify all well design plans; establish a system for near-miss casualty reporting, including anonymous reporting inputs; ensure that a single agency is vested with the authority to ensure safety of offshore drilling; incorporate a net assessment of risks into all future decision processes regarding offshore leasing; require that subcontractors share the responsibility to ensure the safe conduct of drilling operations; expand the training and expertise on offshore drilling within the government; and develop a robust internal safety culture.

6. The administrative functions of government collection of royalties and other revenues from offshore drilling must be separated from safety and regulatory oversight of offshore drilling, as these two functions can create conflicting goals.

B. Liability

1. An important component of offshore drilling safety is an adequate liability regime that imposes sufficient liability on corporate negligence in order to motivate effective safety management by the company.

2. At present, there is no international regime for liability and compensation for damage arising from offshore oil drilling. While Spain is a member of all

Funds in the International Oil Pollution liability regime, it is important to note that this regime only covers tanker and bunker spills, not offshore drilling facilities. As well, it should be noted that even these spill liability conventions do not provide sufficient coverage for worst case spills from tankers or freight vessels, as they minimize liability coverage for non-economic, environmental damages.

3. In 2012, a proposal was made by the Government of Indonesia (in response to the *Montara* blowout in Australian waters which damaged Indonesian waters) to the U.N. *International Maritime Organization* (IMO), to address the issue of an international liability regime for offshore drilling, but the proposal was blocked by other member states including the U.S., U.K., Canada, and Norway. Until an international liability regime for offshore drilling is adopted, offshore drilling liability will remain the sole province of national liability regimes.

4. The *Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations* (EU, 2013) requires all member states to ensure that an offshore oil and gas operator: *is financially liable for the prevention and mediation of environmental damage…from offshore oil and gas operations*.

5. In this regard, Spain's national liability provisions for offshore drilling should be thoroughly reviewed, and verified as sufficient to provide for full coverage of a worst case discharge. This should be clearly elucidated in the EIS. Given that the BP spill in the Gulf of Mexico is likely to cost over $40 billion USD, the Government of Spain should establish *unlimited liability* for offshore drilling projects (at least in cases of gross negligence). The government should also ensure that Repsol, its partners, rig owners, and subcontractors are jointly liable, and have sufficient insurance coverage for a worst case discharge. As well, Spain's criminal liability for gross negligence in industrial operations should be reviewed and enhanced as appropriate.

6. The Government of Spain should establish a national *Oil Spill Prevention and Response Fund*, derived from a nominal (e.g., 0.10 Euro/bbl) assessment on all oil shipped into or produced in the country, as many other governments have established. This Fund should be used by the government to enhance its oversight of oil spill prevention and response preparedness in Spanish waters, in particular its oversight capabilities regarding offshore oil exploration and production. The comparable fund in the U.S. is the *Oil Spill Liability Trust Fund*, derived from a $0.08/bbl fee, currently with a $2.7 billion current balance.

C. Citizen Oversight

1. The EIS provides no discussion at all regarding continuing citizen consultation and engagement after project approval. This is incorporated in

Directive 2013/30/EU on Safety of Offshore Oil and Gas Operations (Article 5, 1.A) (EU, 2013).

2. It has been found that effective engagement of citizen stakeholders prior to and during extractive industry development is essential to enhance environmental safety. After the 1989 *Exxon Valdez* oil spill in Alaska, the U.S. government required the establishment of *Regional Citizens Advisory Councils* (RCACs) to provide greater citizen involvement in managing risks of oil development (PWSRCAC, 2013). If the Government of Spain approves the Repsol proposed drilling project, a *Canary Islands Offshore Citizens' Advisory Council* should be considered for establishment.

3. A *Canary Islands Offshore Citizens Advisory Council* would need its own annual budget (from industry or government resource revenues), staff, and independent appointment of council members representing all major citizen stakeholders in the islands, including fishing, tourism, local governments, conservation organizations, and the scientific community (Steiner, 2013). The Council should remain autonomous from the federal government and industry. The Council should be mandated to provide oversight of all proposed and ongoing offshore extractive development in the region. If the proposed exploratory drilling project is approved, the Government of Spain should require the operating company, as a condition of its permit, to provide a minimum of $5 million/year to fund the Council. The Council should provide review and continuing oversight of all aspects of offshore development in the region.

VI. Conclusion

Given the extensive insufficiencies and omissions detailed above, this expert review concludes that the Repsol *Canary Islands Environmental Impact Study* (EIS) is *not fit-for-purpose*, and respectfully recommends that the Government of Spain decline to accept the EIS, and deny the exploratory drilling project as currently proposed.

VII. References

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Appendix I   Reviewer Bio

The author/reviewer has worked extensively in the field of marine oil spill prevention, response, damage assessment, restoration, and policy around the world, advising governments, industry, the U.N., and NGOs on offshore oil and oil spill issues. Some highlights of this work follows:

- Alaska – Professor and marine conservation biologist at the University of Alaska from 1980 – 2010. In early 1980s conducted workshops in Arctic communities re: risks of offshore oil development; participated in 1989 Exxon Valdez oil spill -- advised emergency response, helped develop the U.S. *Oil Pollution Act of 1990*, co-founded the *Prince William Sound Science Center*, initiated establishment of the *Regional Citizens Advisory Councils* (RCACs), and proposed settlement of government/Exxon legal case; continued public outreach on offshore oil/ environment issues. Helped found and served as Facilitator of *Shipping Safety Partnership*.
- Russia – Co-Principal Investigator for project on oil spill prevention and response on Sakhalin Island; served as foreign technical expert on public review commission for the Siberia Pacific Pipeline project, advised Russian government and Duma on oil royalty and taxation issues, and served on IUCN / Shell independent science panel to provide technical review the Sakhalin II project in relation to the critically endangered Western Pacific Gray Whale.
- Kazakhstan and Azerbaijan - Worked with civil society groups to enhance oil sector and government transparency.
- Africa – Nigeria, worked with Nigeria Ministry of Environment, NGOs, and state governments in assessing damage from oil development in Niger Delta; and served as expert witness in lawsuits re: environmental damage from oil. In Mauritania, participated in workshop to enhance citizen involvement in offshore oil sector oversight.
- Pakistan - Developed and served for Pakistan Ministry of Environment / Environmental Protection Agency and UNDP as *Chief Technical Advisor* for first comprehensive oil spill Natural Resource Damage Assessment in a developing nation in 2003 – 2004, for Tasman Spirit oil spill in Arabian Sea
- Lebanon - During Israeli/Hezbollah war in 2006, advised the government of Lebanon on issues regarding the Jiyeh oil spill caused by Israeli air strikes; briefed the Israeli government in Tel Aviv on the spill and recommended financial settlement from Israel to Lebanon.
- China – Advised Chinese NGOs and media on Dalian oil spill, 2010.
- Gulf of Finland – Conducted workshops in 2005 on behalf of U.S. State Department on oil spill prevention & response in Finland, Russia, Estonia.
- Canada – Advised Indigenous tribes in B.C. re: risks of oil transport
- U.K. – Advised the *Shetland Islands Council* on *Braer* Oil Spill, 1993.
- U.S. – Conducted several projects in U.S. re: oil spill prevention and response, including for state of Hawaii, advised groups in Gulf of Mexico BP *Deepwater Horizon* spill in 2010, many speaking engagements re: risks of oil, etc.
- Belize – Conducted rapid assessment of environmental aspects of oil development in Belize for citizen's coalition (2011).
- Other - Authored dozens of technical and popular publications on environmental risks of oil, including international manual on environmental damage assessment and restoration after large marine oil spills for UNEP and IMO, commented regularly to media on oil risks, reviewed offshore oil documents for NGOs in New Zealand and Greenland, etc.