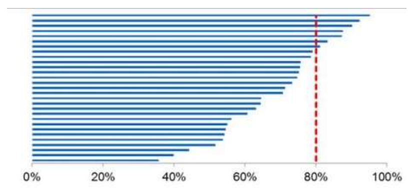
2016 PE Exercise Query Register

No.	Query	Clarification
1	Losses owing to lack of water injection & definition of SMPP & EMPP: The guidance notes indicate that losses owing to lack of water injection can be classified either as “reservoir” or “injection system”. This appears, at first hand, to be a “double dip”. Can you please clarify which loss category should be applied.	Losses associated with reservoir refer to the asset strategy decisions for maximising economic recovery of hydrocarbons from the reservoir (ie if the annual asset plan requires a certain volume to be injected to maintain reservoir pressure and the asset does not achieve that due to subsurface issues , then the loss would be recorded against reservoir) Should there be issues with the water injection delivery system, that prevent the water injection system delivering the annual asset water injection target (eg integrity of pipe, WI pump failure etc) then such losses will be recorded against the water injection system
2	Definition of SMPP & EMPP for fields sensitive to water injection rate: Given the retrospective nature of the submission, we require clarification on the definition of Wells MPP for fields that are particularly sensitive to water injection and voidage replacement rates. Can you please clarify the basis of which Operators should set WMPP in these instances?	The Field Operator is responsible for developing an asset strategy to maximise economic recovery of hydrocarbons from the reservoir. This strategy has in the past been the subject of reviews with DECC / OGA and going forward will be the subject of a detailed evaluation by the OGA, part of the Enhanced Asset Stewardship assessment process Hence the relevant technical authority within the Operators organisation shall be the determinator of the field development strategy (and hence water injection rate) and should be able to justify that to the OGA
3	Installations currently shut in owing to uneconomic production: For installations that are currently shut in owing to uneconomic production & potentially awaiting formal acceptance of cessation of production by the regulator, can you please clarify the approach to be taken with regard to potential setting and loss categorisation in this case? The guidance notes remain silent with respect to this particular case.	The Field Operator is responsible for developing an asset strategy to maximise economic recovery of hydrocarbons from the reservoir. This strategy has in the past been the subject of reviews with DECC / OGA and going forward will be the subject of a detailed evaluation by the OGA, part of the Enhanced Asset Stewardship assessment process. Hence the Operator should record the production strategy (and volumes) that has been submitted to the OGA as part of the CoP process and record actual production, loss against the production strategy and remaining uneconimic production potential (that will not be realised as the asset will cease production)
4	Parity of Economic Tests across Operator Groups: How do we ensure parity of economic assessment across Operator groups if each Operator’s economic evaluation criteria is applied? Diversity of approaches wrt. Economic assessment will yield inconsistent comparisons between Operators.	The responsibility of the Field Operator is to provide backup detail to production that is impacted by an Operators economic decision. The Operator has to forward (under separate cover to the template) the justification for the economic decision. This justification will be subject of review as part of the OGA's Enhanced Asset Stewardship review process (which is to be rolled out to industry 2016). As guidance on what to submit, please reference the data that is required as part of the Field Development Plans (ie the Common Reporting Format (CRF) sheets). The justification should be based around providing similar basic information plus a summary of the Operators economic assessment The OGA will use its own economic criteria to independently assess the economic viability of the justifications, hence providing an independent basis for assessment and parity across returns
5	Cross border fields – should we apply the UK equity to SMPP calculations?	Yes
6	Well production potential a. Dry oil production? – does it includes NGL b. Gas flow rate corrected to export conditions – doesn’t include fuel and flare?	a) The oil production data entry tab refers to all liquid hydrocarbons that leave the hub/ facility hence yes, includes NGL's exported in liquid phase b) Fuel and flare shall be reported in standard gas units mmscfd

7	Regulator's approval for wells out of SMPP – what form of approval?	Refer to the answer to query no 3 If well stock has been recently reviewed with the OGA (part of the asset stewardship or reserves exercises) and a reduction in well potentail agreed then well stock can be amended / removed accordingly. If no discussion has taken place recently then relevant technical authority within the Operators organisation shall be the determinator of the field development strategy (hence well potential and removal of well stock from potential) and should be able to justify that to the OGA at the next Enhanced Asset Stewardship review session
8	For how long is the uneconomic production potential is carried from/to? e.g. if a well needs a workover and is not economical since 2000 should It be included in the uneconomic prod potential?	The Field Operator is responsible for developing an asset strategy to maximise economic recovery of hydrocarbons from the reservoir. This strategy has in the past been the subject of reviews with DECC / OGA (including discussion on well potential that should form the basis for this return). If no recent discussion has taken place (eg stewardship or reserves discussions) then the Operators technical authority shall decide the potential to include. This will be the subject of a detailed evaluation by the OGA, as part of the upcoming Enhanced Asset Stewardship assessment process
9	How will the OGA 80% PE target be measured: on an overall production-weighted average (or reported by field/operator)?	OGA will report anonymously by individual hub using output from the PE template, for UKCS (data from all reporting hubs) i.e . 
15	The constraint for one of our assets changed throughout the year from Wells to Export and the correct way to illustrate it would take the Annual SMPP from the sum of minimum SMPP's per each month. For our asset, an excess of well potential in the 2nd half of the year results in the minimum cumulative SMPP becoming the export constraint for the entire year (because the wells SMPP exceed export) – but it was in fact well constrained for the first 6 months. Using annual cumulative figures negatively impacts production efficiency. Which method is correct? Monthly or annualised?	MPP should use monthly (or other appropriate period), summed over the year to come to an annual aggregate of choke MPP. As correctly noted, there could be a change in the constraining choke from one month to the next. In this case please add an explanatory note to your data submission.
16	The template calculations for efficiency appear to have a discrepancy contained within them. According to the template PE=(Actual Oil (Boe)+Actual Gas (Boe))/SMPP. So if our SMPP is constrained by wells the you get the following: PE=(Actual Oil (Boe)+Actual Gas (Boe))/(Wells Oil Potential (Boe)+Wells Gas Potential (Boe)), which is absolutely fine. However if our SMPP is constrained by Plant (and our primary product is oil), then you get the following PE=(Actual Oil (Boe)+Actual Gas (Boe))/(Plant potential (bbl)), which seems to be inaccurate way of calculation the efficiency, because it means adding Gas actual production on the numerator which is not accounted for in the denominator (SMPP plant constraint with oil only). This is applicable to our asset because it is currently Plant constrained on oil primary product. If we use the approach per the template, we often exceed 100% efficiency due to beneficial effect of only accounting for gas on the top of the equation. Clarity sought on whether PE should be based on combined product stream or primary product only.	If 'plant' represents the system choke (i.e. plant potential determines the SMPP/EMPP), the primary product, whether oil or gas, will be produced along with associated product (i.e. gas or oil respectively). If plant is the limiting choke defining SMPP/EMPP, the calculation of SMPP/EMPP should be: the sum of the oil and associated gas, if oil is the primary product, or; the sum of gas and associated oil if gas is the primary product.

17	3. Section 4.1(f) of SPE 'PE Reporting Best Practice Guide' specifies: "Where artificial lift is installed, the well potential shall be expressed as total potential inclusive of any uplift from artificial lift;". However, later in examples Section 4.3.16 it states: "Well potentials are based on the maximum lift gas available. Plant potential is determined by gas lift capacity which becomes the SMPP. Maximum potential rate is added to either EPP or UPP and any capital work to remove constraint would be a planned loss." One statement says total potential inclusive of uplift and the other says gas lift capacity (and not total potential). So if a safety case only allows gas lifting 6 wells at any time, is the Wells Production Potential determined using six gas lifted wells? Or is it based on all 20 wells being gas lifted.	Please discuss with SPE contact to gain clarity regarding the application of section 4.1 (f) The OGA's interpreation for the return is; - If the safety case imposes a limit on gas lift capacity, that should be used to determin the well MPP Any potential that could be achieved by removing that constraint should be the subject of discussion at the Enhanced Asset Stewardship Review.
18	Section 7.2 of SPE 'PE Reporting Best Practice Guide' for Market choke states: "Nominations do not include "best endeavours" element of contract. This means that fields can legitimately achieve over 100% MPP. All reviews and the basis thereof shall be formally documented and approved by competent personnel." This effectively means that e.g. our field IPC is currently constrained by Market Choke (a pipeline contractual FMQ) and we are regularly producing over 100% efficiency. Everything we produce above FMQ is termed "best endeavours". This will result in losses being masked and not reflect true production efficiency.	Following review of PE templates already submitted, the OGA believe that the Market choke in many cases is unlikely to be the primary choke (i.e. defining SMPP/EMPP), either the Wells, Plant or Export system would be the primary choke. Should the facility that the PE template is being completed for have the market choke as the primary choke please contact the relevant OGA facilities engineer for further guidance.
19	We have two cases where misallocations in 2011 to 2014 have led to repayments in 2015. How should we capture this in the new template?	The OGA position is that the asset should report against the actual potential, actual production and production loss recorded in the reporting year (and not reconciled for contractual / commercial amendments)
20	Our Netherlands assets have not been provided with a template (which would be the processing hub). Is this because the gas produced in the UK sector goes to the Netherlands?	All UKCS Field Operators have been provided with a PE return to record UKCS production. Where possible, the PE of the processing hub should be obtained (but the OGA accepts this may not be possible for all non UKCS processing hubs for this PE return) . Please contact your OGA focal point to discuss further
21	For our facility hub we expected to have to account for fields with a different ownership as these are piped through (but not processed) the hub facility (NUI) before flowing to the onshore terminal for processing. Is this correct or is it because our company only support transportation and not processing that it would sit with the issued PE returns?	This years updated process is based upon identification of the most appropriate offshore facility that can be classified as a hub facility (given we are not including onshore terminals in this years return). Hence your NUI facility has been deemed to be the most appropriate facility to be classified as the "hub facility" for the HC delivery infrastructure in that area. The decision is based purely on a technical evaluation - and as discussed at the workshops, can be discussed further with your local OGA focal point
22	On the tab for "Supporting Info" you ask for "Facility/platform/hub infrastructure connectivity diagram". For our offshore hub facility should this could include all the assets and wells or will it be for the hub facility only?	The request is for a general drawing that shows the connectivity of the infrastructure and where possible Process Flow Diagrams (PFD's) of the main product flow across the hub facility. If PFD's are not readily available, please use diagrams from the safety case submission to show main product flows
24	We are unsure how to capture our fuel and flare for our field as it occurs at the terminal and the template only allows for this at the hub - which would be the offshore NUI if we have understood the definitions correctly. Where should we capture this information?	The PE data collection template is based upon use of fuel gas / generation of power offshore If your asset generates power onshore, I would not log that fuel gas usage Flare volumes for the field should be reported as per the issued flare & vent consent for the offshore field / facility
26	Just for clarification am I correct in that third parties producing through our Hub (e.g. Field production by others through our offshore NUI) need to provide us with whether their losses are Reservoir, Wellhead or Completion so we can allocate it to the correct row?	As per the email issued by Cindy (14 Apr), the Hub operator is to request from the Field Operator the well MPP and associated well losses (Reservoir, Wellhead or Completion). A template has been issued to help Hub Operators with this data request
28	The asset cluster has one flare consent for all fields in the cluster. Shall I enter flaring from both the non operational hub facilities as satellite flaring in the hub facility submission?	Yes, all FLARE consents are consolidated into one FLARE volume for the hub facility, for entry into the PE template

29	The returns make a distinction between Satellite flows that are ‘processed’ at the hub versus other flows that are not. The decision whether to include other data is based on this distinction of whether the gas is ‘processed’. One example I have is for the issued hub return. We have no separation or compression on the platform designated as "hub" where another field comingles in the hub, however I am not sure if the commingling process constitutes ‘processing’ or exactly what constitutes fields that go “up and over”. The issued PE return template describes other field as a Satellite field on the Front Sheet, but I am unsure whether to include the other field data in the return. Can you also confirm if my general interpretation of the guidance is correct: A Satellite field coming through a hub, which does not undergo any processing at the hub, would not need to be included in the gas/oil export or Satellite data fields, but that a field which underwent separation (for e.g. metering purposes), but did not undergo any other processing, would need to be included. Is that correct?	This years updated process is based upon identification of the most approriate offshore facility that can be classified as a hub facility (given we are not including onshore terminals in this years return). Hence your facility has been deemed to be the most appropriate facility to be classified as the "hub facility" for the HC delivery infrastructure in that area. Hence this interpretation could include some fields that feed directedly into the export pipeline. The decision is based purely on a technical evaluation of the infrastructure / last facility before the combined flow enters the export pipeline to shore. As discussed at the recent PE workshops, the majority of field production will flow to the hub facility without processing (hence classed as hub fields). The hub facility will then process the well flow to meet export specification (eg pipeline or tanker export specification for HC liquids, pipeline or injection specification for gas export). The word 'processing' has a specific meaning, and invloves a compositional change of the fluids. Therefore an up-and-over oil line which is pressure boosted only on the hub facility is not considered as 'processing' as there is no compositional change. A Satellite facility normally will not process well fluids to export specification hence will flow partially processed hydrocarbon fluids to the "hub facility" for final processing to export specification. For your specific example, the recommendation is to discuss directly with your OGA focal point
30	For the provision of information from other field operators to us as Hub operator, the guidance states that the other party should provide their WPP and details of their losses under the Wells choke. Where the other parties operate a field which has its own topside(s), should they also provide details of their PPP and losses under the Plant choke, in order to give a full picture of the situation prior to the hub level?	As discussed at the recent PE workshop, if the other party facility undertakes full processing to export spec. streams then it should be split out as a separate hub. If the other facility undertakes partial processing and the hub facility completes the processing to export spec, then the hub facility PE will represent the PE of that system. The other platform in this case will be associated with 'Satellite fields'.
31	In the issued hub template, three fields have been considered as Satellite fields when the rest have been classified as Hub fields. All fields are operated by <named operator> and a 3rd party field is actually producing through platform facility (classified as Satellite). Could you please then explain the difference in categorization? In the case this categorization is right, then do I have to report the 3rd party field production under Satellite in the return?	As explained at the workshops, the design of the 2015 PE returns is based upon industry guidance ie the SPE Production Efficiency “Best Practice” white paper. The best practice paper uses a 4 choke model to capture production loss, based around a hub facility concept and does not recognise ownership… it’s a simple structural production model Hence as per the definitions in the template: - Hub definition / hub fields The facility/platform/hub that received hub field production and processes hydrocarbons to export spec. Hub fields are those whose wellhead production is gathered and processed on the facility platform/hub - Satellite fields are those whose production is routed from a separate facility (where some level of processing takes place) to the hub facility/platform/hub where additional production processing occurs (in the hub facility) prior to export. You are correct to report the 3rd party data under the 'Satellite' category in the return.
33	Annual Shutdown Durations – In some areas we do not always take complete Hub shutdowns in a single period, in order to minimise disruptions. For instance, in the Amethyst Hub, we had two of the four topsides offline for annual S/D works in June (~10 days) and the other two topsides in August (also ~10 days). At no point was the entire hub offline for Annual Shutdown. How should we report this, as to put in 20 days planned/actual would not represent the outages taken. As the full hub was not taken offline, would the Annual Shutdown duration be considered zero days, or should we report the longest single planned period for the platforms (i.e. 10 days)?	My guidance to hub facilities is only to include a full hub shutdown duration. If the hub facility undergoes a partial shutdown (or a partial shutdown of the gathering system occurs), then the recommendation is that this loss is recorded under the PLANT choke (for gathering system loss) using the “full plant” loss category (using the part of the definition noted below), i.e. "This category is to be used to record loss associated with a total plant (all system) outage, or combination of system outages that results in no production export or a shut down for a duration of more than three (3) consecutive days."

34	Some of our internal loss reporting categories do not map particularly well onto the OGA loss categories, please could you advise which OGA category you feel the following examples would best fall under: o Bad weather preventing flights to reset a NUI o Nearby simultaneous operations (SIMOPS) that prevent production in adjacent wells/fields o A spurious Fire & Gas detection that results in a platform shutdown (< 3 days so not applicable to 'Full Plant') – would this be under the 'Control System' category?	• Bad weather preventing flights to reset a NUI The recommendation is that you use the PLANT choke, " full plant" category… using the definition guidance notes for this category ie "weather delay that impacts production (e.g. sea state, volcanic action etc)" • Nearby simultaneous operations (SIMOPS) that prevent production in adjacent wells/fields The recommendation is that you log this loss under the PLANT choke, " Gathering system" category ie "This covers the loss from flowline network and process facilities that transport and control the flow of oil or gas from the Well wing valve to Plant." (In this instance SIMOPS has impacted upon the control of fluids from Wellhead to Hub facility) • A spurious Fire & Gas detection that results in a platform shutdown (< 3 days so not applicable to 'Full Plant') – would this be under the 'Control System' category? The recommendation is as you correctly surmised…. PLANT choke, "Control system" category ie "This covers the loss from: - systems that control all Plant systems (where control elements are distributed throughout the system through a communications network or which use a single controller in location) - Safety Instrumented Systems (SIS, ESD etc.) consisting of an engineered set of hardware and software controls which are especially used on critical process systems"
35	Field <> was due to start up as forecast in 2015 but it's start-up has been delayed to 2016. The hub Operator do not benefit of any physical production from this field. Why is it listed in our PE report? Should it be listed as a Satellite field?	As you say, the new field should have been producing in 2015. Hence the loss in production for 2015 should be logged as Sanctioned Capital Project Delay (ie forecast production from original startup date to end of 2015) It is not a Satellite field as the hub facility fully processes the fluids.
36	Should <new field> be included in this section? <new field> doesn't give us any production increase so this value would be 0 anyway.	As you say, <new field> should have been producing in the reporting year. Hence the loss in production to be logged is the forecast production from original startup date to end of the reporting year.
37	<Asset facility> treatment capacity? Can you please clarify the definition of "primary Product"?	The Plant Maximum Production Potential is the constraint that limits the HC throughput of the Hub. The specific constraint is facility dependent. In some cases with Northern facilities, the plant constraint is the water treatment capacity (which limits the amount of HC liquid product that can be processed through separation etc) In some Southern gas facilities, the plant constraint is gas compression (especially for low pressure operation), which limits HC gas production. Hence the expectation is that the asset works out the most onerous plant constraint within the facilities, agrees what impact the internal plant constraint has on the primary HC export product max flow (could be oil or gas) with the Operators plant/facilities technical authority and logs the answer.
38	We deliver oil to floating storage and gas by pipeline to shore. Should we include storage capacity and maximum flow line flow ?	The asset needs to establish which export route impacts/constrains production the most… then enter the value for the constraining export choke Eg if the oil export route limit is 100 units/ d (and 120 gas units/d can be exported at this rate), but the gas export pipeline max rate is 80 units/d (which results in a maximum oil export rate of 66 units/day) … then the gas export pipeline route is the constraining export choke and this is used to set ExMPP
39	Should we indicate the maximum flow that the buyer can receive? Please clarify	Only fill in this data entry point if the market choke is the choke that is most constrained out of the 4 main chokes (wells, plant, export, market). If one of the other chokes is the constraining choke, then please leave this blank. For the vast majority of assets the market production potential does not represent the most constrained choke. If you believe it does, please discuss with the OGA.
40	NUI operators are currently reporting all their losses as wellhead losses even if they are actually due to power/utilities etc. as Reservoir/Completion/Wellhead are the only sections of the form they are permitted to enter data into for losses (based on the NUI Operator template sent out by yourselves). This is ok at a basic level but may give the wrong signal when analysed in the future and is different to similar NUI's operated by ourselves which have been correctly recorded against the appropriate loss.	OGA will raise the issue with the SPE … to widen the source of loss within the reservoir envelope. Meantime please choose the most approprite loss category.

41	At the beginning of 2015, an economic project was included within the 2015 asset plan. However, as progressing into the year with the declining oil price, the project was put on hold for further review. It was then decided to delay the project for the reasons below. • The project then become marginally economic or uneconomic based on the range of oil prices run for economic sensitivity and the project incremental forecast ranges. • Further technical work is then required in order to test for the well potential prior to committing to the project. Following that, the project was not executed in 2015. In such case, should the project potential be included as EPE, UPP?	When was the project originally planned to be completed in 2015 and at what point did the economics cease to be positive? Depending on your feedback the following could apply: i. If the decision was made that due to declining oil price and it was found to be uneconomic prior to the original target implementation date, then I would suggest you include this under UPP, from the time of the original forecast implementation date ii. If the economics were still positive but the works was slipped / delayed, then it should be allocated under CPD
43	The Hub Operator raised a query that because oil production from their Hub facility was limited by the ever decreasing limit that BEIS puts on the asset with regard to oil-in-produced-water overboard discharge spec. (which may be less that the statutory minimum discharge concentration) is this loss allocated as Market Loss under Government/Regulator direction.	The answer to this is 'no'. OGA advice is to record this loss as Plant Loss due to the Produced Water System. If the loss is as a result of a BEIS requirement, then please speak to the OGA about this separately, as OGA may be able to help under its remit of maximising economic recovery of UKCS hydrocarbons.
44	Prior to submitting this information, as Hub Operator I would like to take some guidance from you with regards to the Economic Production Potential figure. Initially I believed that this was the <Staeliite Field> Production figure, however I've completed this within the WMPP box. As the <Satellite Field> didn't have a Project that was realised, then should the EPP figure be 0.	I've reviewed your query re. the data requested of <Satellite Field> by Hub operator. It is correct to record the mmboe as WMPP (Wells Maximum Production Potential). With regard to well XX. If it was in the plan to bring XX back in to production in the reporting year, then this would be classed as EPP (as presumably you wouldn't do it if it wasn't economic). If it was not completed when planned, then the expected production of XX would become a loss under Sanctioned Capital Project Delay. If XX was not in the plan for the reporting year, AND an economic analysis has shown that the intervention is uneconomic, then the potential should be recorded as UPP.
47	Our test separator largely has been used as production separator to maximise production. Question: should SMPP be reduced for well testing or well testing activities be captured as a loss (ie reservoir loss)	As this is the current mode of operation, the SMPP should reflect the use of the test separator as a production separator, but SMPP may be reduced for well testing.
48	I included losses from inadvertent shutdown system activation (one accidental knock, one button failure). Is this the best place for these or do you want to drill down to genuine control system failures in this category	I would say record under 'control system', especially for button failure. Use judgement for artificial knock, but always add a comment to explain.
49	if the losses are due to an external / other company activity, where should this be included? What happens if we process their hydrocarbons	If you process their hydrocarbons, then they will be classed as a Satellite or Hub field, and their losses will be recorded in an appropriate loss category, depending on the issue. Otherwise it would be 'force majeure' (in export or market)
50	Can you explain the boundary between the Export & Market Chokes for Production Efficiency?	I would suggest that the Market Potential (Market Choke) is the maximum combined quantities of hydrocarbon products (boe) delivered at the custody/duty transfer points, that the market, or buyer, would take or purchase. (In reality, only a small fraction of the hubs we deal with have a definable market potential, and in most cases it can be ignored). Market Potential is set by contract or commercial terms, whereas Export Potential is set by physical limitations (e.g. flow, pressure, availability of infrastructure etc.). If you believe you have a market Choke which defines the SMPP, then please speak to the OGA to clarify.
51	<field> reports production on a calorific value as each amount has a different calorific value. Can this be used for PE Return or does it have to be mmscfd?	It has to be in mmscfd