CLG QUESTIONS SUBMITTED BY PAUL ANDREWS – RESPONSE

Whilst reading Third Energy's response to these questions, it should be taken into account that these are largely broad, high level responses to some very technical questions. They should not be used as definitive answers that can be applied to all circumstances.

Please note that these questions are reproduced verbatim from the PDF document supplied.

Q1 *Is lateral drilling more expensive than vertical, if so by how much and for what reason?*

A First it should be said that a well that starts vertically can then be drilled as a lateral. In these circumstances, the drilling will be carried out by the same rig and as a continuous process. Alternatively, a vertical well can be re-entered and then drilled laterally.

A lateral well, in general terms, could cost more than a vertical well because of the extra footage and time involved. However lateral drilling on a cost per foot basis at the same depth can actually be less expensive due to faster penetration rates. This depends on the need for directional control and sophisticated bottom hole assemblies to follow the geology and to stay a certain height above or below a certain formation. It can also depend upon the quantity of real time LWD (Logging while Drilling) that is required. It can also depend on the length of the horizontal section, borehole stability, build angle, dog leg severity, hole cleaning and mud properties to name just some of the parameters that go into the calculations.

Q2 *Once drilled and ready to frack how are different fracks facilitated, how are the different sections isolated and pressure maintained?*

There are many ways to fracture a horizontal section and many ways to isolate it. A common method involves starting at the toe of the well and fracking several sections at one time, after which the section is isolated by one of several different options. Whatever method is used to isolate the most recent fracked interval, the reservoir pressure inside that section is maintained.

Q3 *Is the steel pipe in a lateral section surrounded by concrete when it is fracked?*

Firstly, cement not concrete is used in wells. The industry uses cements which are highly scientifically engineered products offering superior performance. For example, there are cements on the market that are high-tech self-healing products which have increased elasticity and resilience.

With regard to any potential future lateral wells drilled by Third Energy, casing will be cemented in place using high tech cementing products to ensure robust well integrity.

Q4 *What determines the limit to lateral drilling? Is it the ability to get straight sections of steel pipe round the curve from vertical to horizontal? Is it the limit of force that can be applied to the steel pipes at the well head?*

The limit to horizontal drilling depends on many things including drilling rig size and power; geology; cost; and even the licence boundary.

Contrary to many of the simple illustrations of the subsurface, when a well turns from the vertical to the horizontal it is not through a 90 degree angle. Instead the deviation is very gradual.

The ability of the drill pipe and casing to turn from vertical to horizontal is taken into account in the planning of the well. So long as the build rate is smooth and the dog leg severity is not too great, the deviation tends not to play a significant role in determining the length of the horizontal section. There is "no force" applied to the steel pipes at surface.

Q5 *If it were possible to drill and line the lateral section as far as Wytch Farm in Dorset (10km I believe) could sufficient pressure to frack be achieved at that length, at least theoretically?*

Yes, theoretically, sufficient pressure could be achieved. It should be noted that a form of hydraulic fracturing, in combination with directional drilling, has been used effectively to produce oil at Wytch Farm.

Q6 *Would it be the case that once gas begins to flow, it would not make commercial sense to stop that in order to drill further laterals? Indeed would it be possible to stop the flow of gas from any given lateral to drill further laterals?*

In answering this question, we have assumed that it is in reference to a well site in commercial production rather than in the exploration or appraisal phases. It is highly unusual to have commercial quantities of gas and a means of realising its commercial potential during these phases.

The need for drilling more laterals would normally be driven by economics. Before any future laterals could be drilled the gas flow would have to be stopped, isolated and tested. This is a common operation in the oil and gas business.

Q7 *If some form of well failure was detected, perhaps a bond between the concrete and the well itself or between the concrete and the steel EXACTLY how would this be repaired to ensure no leakage to the surface? Current pipe failure examples in California would suggest it might take some months to effect a repair and would the solution rely on drilling a new well to intercept to point of failure and provide access?*

A cement failure in the horizontal section and getting a leakage to surface are two different things entirely.

For a leakage to occur at surface, several different safety barriers would all have had to fail, one after the other, without being detected. The chance of this happening is extremely small. If it did happen, the well could be fixed and the leak stopped. Again there are many different ways that a leak can be stopped, sealed and tested, depending upon where it is and how bad the leak. This process could take anything from a few days to a few months, depending upon the complexity. A new well would not be needed to stop a leak.

Q8 *If the current EA consultation on reinjection of waste fracking fluid resulted in consent being granted for such re injection where would this take place relative to KM and into what strata*

and at what pressure? Given other (conventional gas) re injection already taking place is there an upper limit for the volume of waste material that could be disposed of in this way, in other words how many mtr3 of waste is it possible to inject into a mtr3 of suitable rock strata and to what extent would this be dependent on the existing water content of such rock?
This question conflates two separate things: the safe disposal of flow back water from the proposed hydraulic fracturing at KM8; and an Environment Agency (EA) consultation.

To be clear regarding the proposed KM8 project: the application for both the necessary EA permits and planning permission from NYCC, clearly state that the flowback water and other waste will be removed from site by an EA approved transport company and be disposed of at an appropriate, EA approved waste disposal facility. Operations will be in line with the permits or planning consent as granted.

Third Energy is aware of the EA consultation. However, at this stage, it unknown whether or not this consultation will result in a change to legislation / regulation and what form this would take. Therefore it is not possible to answer this theoretical question.

Any future water re-injection – whether produced water from conventional production or, if legislation / regulation changes, flow back water from unconventional production – would be subject to the full EA permitting process, including supporting studies, including hydrogeology, and risk assessments.

Q9 *Why is the efficiency if the generator at Knapton so low and how much extra gas be kWh generated are you using? As a result of this inefficiency compared to modern closed cycle generators how much additional CO2 are you causing over kWh of electricity and what are your plans to remedy this situation?*

It would be inappropriate to base any long term modelling upon the performance or efficiency of the station's current LM6000 generator. The incumbent engine is open cycle and with a comparatively low efficiency when set against closed cycle or uprated models. However, the engine does comply with the requirements of the site's environmental permits and is fit for purpose.

Due to the low volumes of gas currently being produced from our conventional fields, the capital investment in an upgrade would not be viable in the short term. If larger quantities of gas were to become available from projects such as the bypassed gas recovery project (BGRP) at the Pickering well PK1 or other potential new reserves e.g. Ebberston South or unconventional gas, increased production would then warrant investment to improve the efficiency of the station's processing and generating capabilities.