Senate Rural Affairs and Transport References Committee

Questions on Notice – Friday, 9 September 2011 CANBERRA

Inquiry into the management of the Murray Darling Basin

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SENATE RURAL AFFAIRS AND TRANSPORT REFERENCES COMMITTEE

Inquiry into the management of the Murray Darling Basin

Public Hearing Friday, 9 September 2011

Questions Taken on Notice – Australia Pacific LNG

1. HANSARD, PG 4

Mr Horton: There are landfills that will take that but I think it is fair to say that there would need to be purpose-built landfills for that. There are waste disposal facilities that will take that volume of waste.

CHAIR: Could you give us examples, on notice, of where those are?

Mr Horton: I think the point is—

CHAIR: No, the point is you just said they exist. Could you let us know where they are and who they are.

Mr Horton: I can provide details of waste facilities that would take that volume of waste.

CHAIR: Of salt.

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CHAIR: But the facilities that say they will take it for money—we have just had an example in the United States where some of these deteriorated coal shale wells have now collapsed, and no one wants a contaminating one like one layer of aquifer to another one. It is 60- to 80-year-old stuff. No one has legal responsibility and the poor old planet is copping it and the cockies have to put up with contaminated water. Who says that the people who say they will take the salt can store the salt safely and where is the environmental approval to do that?

Mr Maxson: I apologise, I have forgotten the name of the facility we looked at as an example of the working one today. We can revert to the committee within the 24 hours with the name of that.

2. HANSARD, PG 6

Senator URQUHART: I just take you to your submission. On page 13 you say that the majority of Australia Pacific LNG's tenement areas lie outside the two areas of strategic cropping land identified by the Queensland government. Do you have a figure of what proportion lies within the strategic cropping areas?

Mr Maxson: I do not have it in my notes today but we could certainly get that for you.

Senator URQUHART: If you could provide that on notice that would be good.

3. HANSARD, PG 7

CHAIR: To save time, can you, on notice, give us examples of increased yields on farms, without identifying the farms?

Mr Maxson: We can do that.

4. HANSARD, PG 7

Senator WATERS: I have a few questions. First of all, I am interested in if there are any standards that apply to the gas well drilling and construction. Are there any Australian standards or is that just dealt with in your conditions?

Mr Maxson: There is a wide range. We follow first our company standards. We are operate around the world. We have been working with the state of Queensland to develop an approved formal set of standards, but we have a very rigorous set of standards that we follow.

Senator WATERS: So there are no government standards. They are just your own company standards at this stage.

Mr Maxson: They are under development and being finalised.

Mr Horton: I can just elaborate on that. The default standard in most cases goes back to the American Petroleum Institute standards which have been developed over the last hundred odd years.

Senator WATERS: Could you give us some more information about that on notice?

Mr Horton: We have in our submission. We have listed, at least for drilling and completions, the key standards that apply. But we can give you that on notice.

Senator WATERS: You could provide a bit more detail on that.

Mr Horton: Yes, we can.

5. HANSARD, PG 9

Senator WATERS: I beg to differ on that, but we might leave it for the time being. On a different aspect now, there have been a lot of claims made by folk in your industry about the so-called greenhouse gas efficiency of coal seam gas as compared with other fossil fuels. This committee has been chasing—so far, unsuccessfully—a full copy of a study conducted by APPEA into this issue and I am hoping that you would have a copy of that WorleyParsons report—the full report, not just the executive summary, and not with any alterations made by APPEA. Are you in possession of the full copy of that report and if so are you able to provide that to the committee on an urgent basis?

Mr Maxson: I do not know if we do have one, I have not asked. I will ask and if we have it we will provide it. We based our work on work that we have done. We had a study done as part of our EIS submission over the years 2008, 2009 and 2010. That would be the one that I think we would be happy to provide.

6. HANSARD, PG 14

CHAIR: You may have to take this on notice: where did you get the figure of 616,000 megalitres—which is on page 24 of your submission—as the current extraction by landholders, farmers, agriculturalists et cetera. You would be aware no one really understands the recharge of the Great Artesian Basin. Could I also ask you to give consideration to one of the propositions put to us by science that, in opening up the seam, some of the old disused and still discharging Great Artesian bores are starting to extract methane with the water because of what is going under the ground. Who should be liable for those fugitive emissions and what are you going to do about it? You can take that on notice. That is in abandoned, rusted old water bores. We can give you examples of where they are.

Mr Maxson: Other water bores.

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Mr Maxson: I apologise, I have forgotten the name of the facility we looked at as an example of the working one today. We can revert to the committee within the 24 hours with the name of that.

Response: Australia Pacific LNG has had discussions with two major companies that handle regulated waste in developing our salt disposal strategies including the Project 'base case' of salt disposal to appropriate regulated landfill. Two sites have been identified that are in current operation that could handle this type of waste and in the volumes that are predicted to be generated. These sites are Ti Tree Willowbank and Swanbank both in South East Queensland.

Australia Pacific LNG has made it clear in its submission dated 6 September 2011 to the Senate Committee (Section 6 (h) page 39) that it is currently actively investigating the alternatives of commercial sale of produced salts and the injection of concentrated brines into suitably stable and isolated geological containments. We are confident that both these options will play a major role in the eventual disposal of the produced concentrated brine and salts.

2. HANSARD, PG 6

Senator URQUHART: I just take you to your submission. On page 13 you say that the majority of Australia Pacific LNG's tenement areas lie outside the two areas of strategic cropping land identified by the Queensland government. Do you have a figure of what proportion lies within the strategic cropping areas?

Mr Maxson: I do not have it in my notes today but we could certainly get that for you.

Senator URQUHART: If you could provide that on notice that would be good.

Response: The Queensland Government's Policy on Strategic Cropping Land (SCL) identifies two areas for SCL consideration – the Strategic Cropping Land Protection Area and Strategic Cropping Land Management Areas. Part of Australia Pacific LNG's Talinga/Orana Tenement Area near Chinchilla falls within the Strategic Cropping Land Protection Area. The balance of the Talinga/Orana Tenement plus the other tenements to be developed by the CSG to LNG Project falls within the SCL Management Area. Within both the SCL Protection Area and the SCL Management Area are areas that have been mapped as being 'potential' SCL based on mapping of the higher classifications of Good Quality Agricultural Land. Within these mapped areas, several criteria need to be met for a particular area of land to be classified as SCL. Any areas identified as SCL based on a 'desk top' assessment would need to undergo ground truthing.

Australia Pacific LNG's main tenement areas being developed for the CSG to LNG Project total approximately 840,000 hectares. We have reviewed the SCL mapping for these tenement areas plus considered the SCL criteria that need to be applied to come up with an initial estimate of 'potential' SCL that could be impacted temporarily during the construction phase and longer term during the operations phase. The results are summarised in the table below:

Estimate of Strategic Cropping Land (SCL) that may be impacted by the Australia Pacific LNG Project over the life of the Project

Tenements (Total land area 840,000 ha)	SCL Map (1)	SCL likely (2)		Construction 7% (3)		Operations 1.3% (4)	
		Low	High	Low	High	Low	High
Spring Gully	65325	4000	6000	280	420	52	78
Combabula	15965	4000	6500	280	455	52	84.5
Ramyard	3295	0	1200	0	84	0	15.6
Woleebee	7914	0	0	0	0	0	0
Carinya	58621	10000	18000	700	1260	130	234
Dalwagon	1200	0	500	0	35	0	6.5
Talinga Orana: Protected	13897	8000	11000	560	770	104	143
Talinga Orana: Managed	3594	1800	3000	126	210	23.4	39
Condabri	12851	3000	5000	210	350	39	65
Kainama	664	0	0	0	0	0	0
Gilbert Gully	16675	2000	4000	140	280	26	52
Totals (ha)	200001	32800	55200	2296	3864	426.4	717.6

Note 1: 'Potential' SCL areas based on GQAL mapping
Note 2: Potential SCL after SCL criteria applied to give a 'low' and 'high' estimate. The estimate has a range which allows for error and some of the cropping land not being suitable
Note 3: 7% of land area impacted during construction based on APLNG Project EIS Studies
Note 4: 1.3% of land area impacted during operations based on APLNG Project EIS Studies

The result of this analysis indicates that out of the total 840,000ha total tenement area, during the construction phase between 2296ha and 3864ha of potential SCL could be temporarily affected which would reduce following initial rehabilitation to 426ha to 718ha during the operations phase of the project (the timing of which will vary area by area depending on development schedule). At the end of economic CSG extraction in each area, final rehabilitation will occur which will then return much of the areas impacted during the operations phase to productive agricultural use.

3. HANSARD, PG 7

CHAIR: To save time, can you, on notice, give us examples of increased yields on farms, without identifying the farms?

Mr Maxson: We can do that.

Response: Stagnant beef cattle prices and rising costs are resulting in problems of low profitability on smaller beef cattle properties in the Western Downs area, in and around our tenements to be developed for CSG. It is likely that a typical property of say 3000 hectares with a carrying capacity of 600 breeding cows, will have little or no surplus income and the additional income from CSG compensation can be very significant to the viability of the farming business. In some cases, CSG compensation payments may change the business risk profile and allow the landholder to consider further property development including alternative more profitable agricultural enterprises such as grain cropping and feed lotting in conjunction with beef cattle breeding.

The effect of a cash flow squeeze on many of these smaller beef properties is that there is a rundown in improvements, because there is no surplus income to maintain fences and watering facilities, or to be able to improve pastures and to control woody weeds. This is evident on many of the properties Australia Pacific LNG has acquired for the location of major gas infrastructure. We have found it necessary to undertake significant capital works (gates, grids and boundary fencing) to secure these properties and to maintain and improve their agricultural productivity (stock yards, internal fencing, stock water infrastructure, weed and feral pest management, regrowth control and pasture improvement).

During the initial stages of gas well development, it is common for a significant amount to be spent installing new grids and upgrading farm roads and fences to provide efficient access to gas infrastructure. This can also be of substantial benefit to landholders, enabling them to access their property more quickly and easily. This infrastructure in many instances will be maintained by the CSG Company.

On the 22 August 2011 the Australian newspaper reported the following story from a Surat Basin landholder:

'Selwyn Maller has no regrets about allowing Origin Energy to drill a well on his 4200 ha cattle station at Wallumbilla, 90km southwest from Wandoan, two years ago. Within the next decade, the grazier expects his 1000 stock will share the farm with about 50 well-heads each producing CSG."We haven't had any arrangements about compensation for that yet. At this stage we've only agreed compensation for that first hole and three more holes. If they want to start pumping we reopen negotiations on that." In the meantime the company has provided his property with new roads, gates and creek crossings. "That's an investment of between $30,000 and $60,000 we wouldn't have thought to make for ourselves" Mr Maller said.'

Landholders have shown a considerable interest in accessing treated CSG water for irrigation. Consultation with 18 landholders in the Miles-Condamine districts proximate to our water treatment facilities resulted in 12 positive expressions of interest in obtaining water. Several of these producers indicated they would add to or substitute water in their existing farming/irrigation programs, while others would construct new irrigation projects to take water if it was available. Estimates of profit from irrigation water vary according to yields and commodity prices, but are generally in the vicinity of $200 per mega litre of irrigation water applied to conventional irrigated farming systems. If a producer was to receive 1000 mega litres of CSG water per annum, it is likely they could increase farm profit by $175,000, after allowing for estimated administrative and service costs.

We have detailed in our submission (Section 2(b) page 16) how we expect to increase yields on properties we own with the availability of treated CSG water.

As a further example, on 15 September 2011, Santos announced a plan to provide treated CSG water to Leon and Ree Price of Mount Hope Station. In their press release Santos reported:

""What we found is that we can expect to boost animal growth per hectare on irrigated land (at optimum rates in normal seasons) by up to 25-fold during CSG water production.

"Cattle on unimproved land sit at one beast per 5ha, but when fed on irrigated leucaena it can improve to up to five beasts per hectare."

Australia Pacific LNG has committed to considerable research into sustainable land use as part of the GISERA alliance with the CSIRO .The research will facilitate better understanding by both gas companies and landholders on the potential benefits of co-existance. The research topics include:

A shared space - provides background, insights, and involvement from the local community to identify issues and lay the foundation for the other projects. This small but focused project is aimed at gaining understanding and engagement in the farming community;

Preserving Agricultural Productivity - looks at the impacts of CSG on land use, agricultural production, natural resource management, economic growth or demography

Gas Farm Design - takes a deeper look at the various farm issues identified during the A shared space project and uses these to inform a single combined farm assessment and design process using detailed case studies

Making Tracks, Treading Carefully - addresses the specific issues of CSG access on land, such as erosion and weeds. It combines farm design, improved agricultural access, design for lower CSG impact and better methods of erosion and weed control into a combined project

Without a Trace - examines the rehabilitation of land both during construction of wells and gathering systems and at the end of gas production

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Senator WATERS: I have a few questions. First of all, I am interested in if there are any standards that apply to the gas well drilling and construction. Are there any Australian standards or is that just dealt with in your conditions?

Mr Maxson: There is a wide range. We follow first our company standards. We are operate around the world. We have been working with the state of Queensland to develop an approved formal set of standards, but we have a very rigorous set of standards that we follow.

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Mr Horton: We have in our submission. We have listed, at least for drilling and completions, the key standards that apply. But we can give you that on notice.

Senator WATERS: You could provide a bit more detail on that.

Mr Horton: Yes, we can.

Response: Australia Pacific LNG has supplied a list of standards that apply (or could apply in certain circumstances) to drilling and completion activities as ***Appendix 1 – refer Page 17***

5. HANSARD, PG 9

Senator WATERS: I beg to differ on that, but we might leave it for the time being. On a different aspect now, there have been a lot of claims made by folk in your industry about the so-called greenhouse gas efficiency of coal seam gas as compared with other fossil fuels. This committee has been chasing—so far, unsuccessfully—a full copy of a study conducted by APPEA into this issue and I am hoping that you would have a copy of that WorleyParsons report—the full report, not just the executive summary, and not with any alterations made by APPEA. Are you in possession of the full copy of that report and if so are you able to provide that to the committee on an urgent basis?

Mr Maxson: I do not know if we do have one, I have not asked. I will ask and if we have it we will provide it. We based our work on work that we have done. We had a study done as part of our EIS submission over the years 2008, 2009 and 2010. That would be the one that I think we would be happy to provide.

Response: Australia Pacific LNG does not have a copy of the full Worley Parson's report so is unable to provide this to the Committee. Our position on greenhouse gas issues is based on technical studies and work completed for and documented in the Project's EIS.

6. HANSARD, PG 14

CHAIR: You may have to take this on notice: where did you get the figure of 616,000 megalitres—which is on page 24 of your submission—as the current extraction by landholders, farmers, agriculturalists et cetera. You would be aware no one really understands the recharge of the Great Artesian Basin. Could I also ask you to give consideration to one of the propositions put to us by science that, in opening up the seam, some of the old disused and still discharging Great Artesian bores are starting to extract methane with the water because of what is going under the ground. Who should be liable for those fugitive emissions and what are you going to do about it? You can take that on notice. That is in abandoned, rusted old water bores. We can give you examples of where they are.

Mr Maxson: Other water bores.

Response: The 616,000ML figure (estimated annual groundwater extraction from GAB) and most of the other GAB figures in our submission and the groundwater fact sheets on the Australia Pacific LNG website come from the Great Artesian Basin Resource Study Update. This is the current update of the Great Artesian Basin Resource Update (Cox and Barron, 1998) commissioned by the then GAB Consultative Council (GABCC). The GAB Consultative Committee (which replaced the Council) commissioned this update. The update is published on the GABCC website http://www.gabcc.org.au/public/content/ViewCategory.aspx?id=91.

The Senate hearings have consistently referred to a figure of 300,000ML (or greater) as the forecast annual off take from the GAB by the CSG industry. Australia Pacific LNG would like to reiterate (as detailed in our Submission Section 5 (b) page 23), that the current estimated average annual off take by the four major CSG to LNG Projects is currently forecast to be about 75,000ML over the next 30 to 40 years. The current off take (in 2011) is significantly less than this.

In response to the question on fugitive emissions from existing (in service and disused) water bores, we would like to further elaborate on the information we provided in our submission (Section 5(f) page 29) on the occurrence of natural gas in water bores in the Surat Basin.

Government drilling records indicate the presence of gas in various concentrations in all GAB aquifers in the Surat Basin back to the beginning of groundwater development in the early 1900's. Australia Pacific LNG has therefore measured the level of gas in all landholder groundwater bores on our tenements while undertaking the baseline survey of these bores. There is abundant anecdotal evidence from landholders of gas concentrations increasing in bores well before any CSG development, and in areas totally remote from any current CSG operations. These increasing gas trends are a result of landholders depressurising minor coals (or multiple coals for landholder bores completed in the Walloons coal measures) intersected in their water bores through their own use of groundwater, basically resulting in a mini-CSG extraction process. In some instances, such as the 'flaming bore' at Hopelands (which has featured in several news articles and 60 Minutes), landholder induced gas discharges can be considerable. The Queensland Government has conducted an independent investigation of this area and has confirmed that there is no connection between the 'flaming bore' and CSG activities.

There is no current obligation on the landholder to control these existing fugitive emissions, however where appropriate Australia Pacific LNG has been providing advice to landholders on potential remedies where such emissions interfere with landholders' pumping systems or have the potential to be a safety hazard.

The only identified circumstances in which there is significant potential for increased gas discharge from landowner GAB bores related to CSG operations is where groundwater bores tapping the Walloon Coal Measures are in close proximity to CSG wells. These conditions prevail over a very small proportion of our tenement areas. Where this does occur, the legislated make good trigger will necessitate make good actions to be undertaken well before there is significant potential for increased fugitive emissions. Nevertheless, our base-lining of gas emissions from all existing landholder bores will enable differentiation of pre-existing and CSG related fugitive emissions.

Additional Questions provided by the Senate Committee via email dated 29 September 2011

Water

What progress is Origin making with its study of reinjection?

Response: Origin as upstream Operator for Australia Pacific LNG is instigating injection trials near each of the two existing and two planned water treatment facilities as summarised in our Submission (Section 6(c)). These trials are at an early stage and scheduled for completion in 2014 before any significantly increased water production will occur. It is too early in the trial program to comment further.

Landholders have indicated that they would be prepared to use suitably treated CSG water as an alternative to accessing their water entitlements. Has Origin entered into any agreements to do this? Are there any technical or regulatory impediments to doing so?

Response: Australia Pacific LNG does not have any current water supply agreements with landholders. We fully support this option as being a preferred option for beneficial use and have already called for Expressions of Interest in the use of treated CSG water by landholders in several areas of our field development. We will continue to work with landholders in these areas and landholders in our other development areas to look at the feasibility of the provision of treated water as we continue to develop our Project (please refer to our Submission Section 6 (e) page 36).

Any Agreements we reach will need to meet stringent regulatory approvals and will be subject to a range conditions covering ongoing monitoring and compliance reporting. Some landholders may consider these water supply conditions as being difficult to meet.

On pages 23-27 you discuss the question of the possible impact of CSG water extraction on groundwater and aquifers used for agricultural, domestic and industrial purposes. You state that, "CSG production only extracts water from the coal measures. It does not directly extract water from aquifers commonly used for local user's water supply." Can you comment on fears that 'depressurising' of coal measures will, over time, cause water to flow from aquifers into the coal measures, thus reducing volume and pressure in the aquifers, and that this problem may not show up until some time in the future?(see p.26)

Response: In the Surat Basin Australia Pacific LNG will be extracting CSG from the Walloon Coal Measures. These formations are generally located between 200 and 1000 metres underground in the project areas. There are many low permeability aquitards of significant thicknesses that separate the coal measures from the most commonly used groundwater supply aquifers. One aquitard example is the Westbourne Formation which is up to 250 metres thick in some places.
These aquitards create a high level of natural isolation between the coal measures and the commonly used aquifers. This means that there is limited potential for activity in one layer to directly impact the other and removing large amounts of water from the coal measures will not result in large reductions in water levels in aquifers.

However, there is some limited interconnectivity between layers, and as a result there is the potential for a drop in pressure in some aquifers as water slowly makes its way through aquitards towards the Walloon Coal Measures. Although permeable, the water flow in aquifers is very slow and it generally travels at a rate of between 1 and 5 m per year under natural conditions. This means that any potential impacts will be slow to develop and should be identified by the project groundwater monitoring program with sufficient time to implement mitigation measures.

Extensive computer modelling of the impact of depressurising the coal formations has been conducted. The results indicate that CSG activities may cause minor depressurisation in the geological layers directly above and below the coal measures, but in general will have insignificant impacts on groundwater pressure, and therefore bore water levels, in commonly used aquifers.

Australia Pacific LNG has designed an extensive groundwater monitoring program that will operate throughout the entire duration of production operations. This constant monitoring will be compared with the modelling developed by the independent Queensland Water Commission (and overseen by the Federal Government) to ensure any impacts measured are in line with predictions. Ongoing groundwater management decisions for the Project will be directed by groundwater monitoring results.

In some cases landholders directly access the Walloon Coal Measures, or aquifers near the Walloon Coal Measures, for groundwater supply. Where this happens close to proposed CSG operations, bore levels may be impacted by CSG production. In these instances it is the legal responsibility of the CSG operator to make good, or offset, any impacts. Australia Pacific LNG will work closely with landholders to make good any impacts to these groundwater supplies.

Are you concerned that depressurising the Walloon Coal Measures could cause a significant increase in fugitive emissions from existing water bores. (See page 29)

Response: This question has been answered as part of the response to Question on Notice No. 6 above.

Land Access, Land Use & Compensation

On pages 18 and 19 you emphasise the importance of cooperating with landholders to reach land access agreements.

Has Origin had to go to arbitration in many cases?

Response: Australia Pacific LNG (and Origin) has not needed to refer any land access agreements for CSG activities to the Land Court.

Landholders have expressed some concern about gas workers entering properties for routine maintenance tasks being exposed to agricultural chemicals or interfering with scheduled machinery operations. Just as gas companies require visitors to sign in before entering their property, how would you view a requirement that gas workers contact landholders before every visit to ensure that OH & S rules are met and agricultural activity is not disrupted?

Response: Australia Pacific LNG will work with landowners to develop long term operating procedures that meet the requirements of both parties and in particular where there is a potential health or safety risk to workers.

With regard to compensation, (p.21) does Origin have a set formula for calculating compensation, based on the area of land required for its activities, the value of production from the land, impact on land values etc?

Response: Australia Pacific LNG does not use a set formula as such and uses a 'whole of business' approach to compensation as detailed in our submission Section 4 (b) page 21. The calculation of compensation for any particular property will take into account land area impacted and value of production plus other considerations which may vary from property to property. As the aim of compensation is to ensure that the landholder is, as a minimum, no worse off as a result of our activities, it is reasonable to assume that there should be no impact on land values unless demonstrated otherwise.

Where CSG activity required a landholder to make significant changes to farming practices, for example to reconfigure paddocks, buy different types of machinery, or in an extreme case, change the types of crop he produced, would the cost of doing this be included in a compensation agreement?

Response: The scenario posed by this question is unlikely to happen as Australia Pacific LNG seeks to work with a landholder to locate CSG infrastructure to allow the existing farming activities to continue. In situations where this is not possible, changes to farming practices would be included in the calculation of compensation. Where Australia Pacific LNG plans to construct and install major production infrastructure (gas plants, operations camps, water treatment facilities etc) which would be more disruptive to a normal farming enterprise (particularly during the construction phase), we will normally purchase a property on which to locate these facilities.

Many witnesses to the committee have talked about the social and emotional impacts of having CSG related activity on their land. Does Origin include this in its compensation agreements and, if so, how is a value put on such impacts?

Response: Australia Pacific LNG is looking at programs to be provided by accredited third parties (and that are being discussed with local Agforce representatives) that will support landholders in these areas.

Wells & pipelines

On page 14 of the submission you discuss the factors to be taken into consideration when selecting sites for wells etc. How much flexibility exists in the actual siting of wells? Can the generally be placed on non-productive land or on the periphery of properties?

Response: Australia Pacific LNG has been able to work successfully with landholders to place wells and associated infrastructure (pipelines, access tracks etc) in a way that limits the impact on the landholder's activities. This includes placement on low (and non) productive land, on fence lines etc.

Pipelines may not be sufficiently deeply buried to allow ordinary farming activities on the ground above the pipelines. For example, large headers may weigh as much as 35 tonnes, and farmers have been advised that such machinery should not be used above pipelines. Comment?

Response: When finalising CSG development plans for a property, Australia Pacific LNG works with landholders to understand current and possible future land use options. We are not aware of any farming practices (including the use of 35 tonne headers) which cannot be safely allowed for in the design of gas and water gathering or transfer pipeline systems. It is important that discussions on planned and potential future land use are held early in the design phase for a property so that appropriate allowance can be made.

Employment of local landholders in CSG related activities

On page 17 & 18 of your submission you discuss the option of using local landholders to carry out some the monitoring and maintenance work associated with gas wells. Can you discuss that in some more detail? (This would have the advantage of minimising the need for gas workers to enter properties – a major social impact that has been raised with the committee)

Response: A program is being developed – referred to as The CSG Essentials Program – which seeks to establish a new collaborative model in partnership with landholders and their employees, whereby they are trained and inducted to undertake CSG operating and maintenance services on a paid contractual basis on their properties.

This model addresses landowner concerns by involving and collaborating with landholders in the project. It will provide a significant and totally new revenue stream for landholders and has the potential to make a major contribution towards a more resilient and financially secure agricultural base within the Surat Basin. A trial program is planned to be rolled out in the second Quarter 2012.

Background to Program

As CSG companies move towards project execution, there has been increased activity around development sites.

Origin as the Upstream Operator for the Australia Pacific LNG Project is seeking opportunities for affected landholders to have a more active role on their land and to opt in or have a choice in playing a part in the growth of the industry.

A program is being developed together with key stakeholders, whereby landholders are able to be contracted to provide on-farm services to the CSG industry. The program will be underpinned by training to meet the required competency standards together with a defined safety training package.

Origin submitted an expression of interest (EOI) for funding under the Queensland Government's Strategic Investment Fund. The EOI was supported as a high priority by Skills Queensland (the funds coordinator), with $250,000 funding being allocated to support implementation of the initiative.

In addition to the landholders; partners and stakeholders for this program include:

- *The Surat Basin CSG Engagement Committee*
- *Queensland Farmers Federation (QFF) - who have agreed to support the development of the job roles and associated training requirements;*
- *AgForce – potential to provide training delivery and landowner support;*
- *Department of Education and Training (DET)/ Skills Qld - Training funding support;*
- *Department of Employment, Economic Development and Innovation (DEEDI) - government lead agency; and*
- *Other CSG/LNG proponents - Santos, QGC and Arrow*

Program Details

Key considerations for the program are shown in the figure below.

Program Task	Actions	Timing
Develop Initial Program Plan	• Develop job descriptions and tasks; • Identify training requirements and potential providers; • Define HSSE requirements; • Develop supervision/management process; • Identify target group for pilot program; • Identify partnerships w. Government, other CSG companies.	Q4 2011 - Q1 2012
Identify Landowners; Contract Arrangements	• Establish remuneration/pay structure; • Determine employment structure/process; • Landowner invitation to participate; • Prepare landowner contract and obtain sign-off; • Identify training provider/s and get contract sign-off.	
Tier 1 Role Pilot Training	• Rollout training to landowners including HSSE training.	Q2 2012 - Q2 2013
Commence Tier 1 Landowner Roles	• Pilot program landowners conduct land management activities.	
Tier 2 Role Pilot Training	• Rollout tier 2 training including HSSE training.	
Commence Tier 2 Landowner Roles	• Pilot program landowners conduct CSG monitoring and maintenance.	
Pilot Program Evaluation	• Review and evaluation of program; • Stakeholder forum.	Q3 2013
Landowner Training Program Finalised	• Amend and finalise program plan; • Identify landowners eligible for program.	
Rollout program	• Rollout program to landowners across development area.	Q3 2013 onwards

***(Note:** This is the draft program for CSG Essentials – still to be reviewed by key stakeholders)*

Current Position

Origin is developing an initial program plan that identifies tasks; training requirements and suitable training providers; health and safety considerations; remuneration structure and contractual arrangements. Landowners considered suitable for the pilot program will be identified and invited to participate.

The initial program plan, along with landowner agreements to participate in the pilot program is expected to be completed by first quarter 2012.

Training provided will be based on a tiered structure, with tier one focused primarily on land management; and tier two providing further CSG/LNG industry skills. Both levels will include study units from the Certificate Three in Rural Operations and the Certificate Three in Process Plant Operations. In addition, a specific safety training package will be developed and delivered.

This program will ensure that participants gain recognised qualifications which will not only leave a legacy by broadening the regional skills base but provide an opportunity for participants to gain ongoing work in the industry.

Staff training

How do you ensure that all of your field staff dealing with landholders comply with the high standards you describe in your submission?

Response: This is part of the induction and HSE training provided to all field staff. Compliance is tracked by incident and complaints tracking and audit programs.

Do trained liaison staff continue to deal with landholders once access agreements are finalised or does that become the responsibility of production staff?

Response: Origin as the Upstream Operator for Australia Pacific LNG plans to continue to allocate dedicated liaison staff to each landholder over the life of the Project and for this to be the main relationship contact between the landholder and the company. As production activities on properties are expected to continue over many years, it is also expected that the landholder will develop a close working relationship with the company's operations staff to allow any issues to be addressed as efficiently and directly as possible.

The committee has had some comments from landholders who were very pleased with their contact with Origin during the negotiation of the agreement and the exploration phase but feel that there has been some falling off in behaviour now that they are part of a production field and are dealing with a different group of Origin staff.

Response: Origin as the Upstream Operator for Australia Pacific LNG is committed in working closely and constructively with landholders. We acknowledge that in any relationship as complex as that which develops between a CSG operation and a farming operation coexisting on the same land, that issues will arise. Any issues raised by landholders will be treated seriously and appropriate action taken.

Questions of Notice regarding BTEX:

The various bans on using BTEX chemicals in fracking don't extend to banning the BTEX contained in the mechanical lubricants needed for the operation of the CSG wells. Following the reports in the media with regard to the presence of BTEX chemicals in bores at Arrow energy sites in Queensland, it would assist the committee if you could provide answers to the following questions:

Are you able to advise what quantities of lubricants/operation-related BTEX is being used per well, and what is currently done to ensure these chemicals are isolated from the soil/ groundwater?

Response: Lubricants are used, generally after the well has been constructed and barriers such as casing and cement are in place, and as such they do not normally come into contact with groundwater. An average of 10 to 40 litres of lubricants could be used per well including ongoing wellhead maintenance; however these lubricants contain relatively low concentrations of BTEX. Lubricants are stored and handled in line with Australian Standards and any lubricants that contact produced water via the lubrication of surface equipment are contained in tanks or certified and registered lined ponds or transferred by pipeline to water treatment facilities and processed with the produced water . The exposure pathway to cause harm at a sensitive receptor does not exist.

Particularly, is the amount involved comparable/ miniscule compared to the quantities that would be used in fracking?

Response: BTEX chemicals are not added as a component to the frac chemicals, as per Queensland Government legislation.

What quantity of concentration in groundwater would you need from a leakage of these chemicals for it to be a health or environmental risk.

Response: There is no reasonable pathway for exposure at a sensitive receptor as detailed above. In a CSG well the fluid flow and pressure drop is from the formation to the wellbore to the surface facilities.

What mechanisms (and additional redundancies) are currently taken to protect against contamination risks?

Response: Fracture stimulation products and the final fracture stimulation fluids used undergo screening and testing for BTEX before being used in the field. There is an ongoing sampling program to confirm the fluids conform to regulation. The State regulator has an enforcement unit which also takes representative frature stimulation fluid samples for testing.

Several levels of redundancy exist for wellbore integrity and isolation, multiple casings and fit for purpose cement sheaths are in place before any significant amounts of lubricants and greases are used on the well. Fuel and other potential contaminants are bundled and stored and handled according to Australian Standards at surface. Produced fluids are processed in a contained or controlled system.

Australia Pacific LNG adheres to the Queensland Government legislation regarding use of BTEX. More detail on the processes and procedures to ensure well and fracture stimulation integrity can be found in our Submission in Sections 7 and 8.

Do you have any data on the naturally-occurring levels of these chemicals in your area of operation?

Response: Independent studies reveal that BTEX compounds do occur at very low concentrations in some CSG coals which have been tested as part of our exploration and appraisal program. The level of naturally occurring BTEX in coals can vary based on their thermal maturity and the gross transmissivity over time.

Additional Response:

Australia Pacific LNG would also like to respond to issues and claims raised in the submission to the Senate Enquiry and in the hearing by the National Toxics Network related to licensed water releases from Australia Pacific LNG's Talinga gas facility.

Origin manages and operates the Talinga gas facility near Chinchilla on behalf of the Australia Pacific LNG project. The facility's water treatment plant uses the latest reverse osmosis technology to treat water produced as part of coal seam gas production.

Reverse osmosis technology is used throughout the world and is regarded as a reliable and safe water treatment method that produces water of a high level of purity. Importantly, the water produced at Talinga is treated to a level that exceeds World Health Organisation and Australian Drinking Water Guidelines (ADWG) before being released into the Condamine River.

In terms of the parameters of these well established guidelines, the water being released from Talinga is similar if not better than other water treatment facilities supplying water directly for domestic consumption purposes.

This is supported by Australia Pacific LNG's quarterly Water Treatment Facility Discharge Report for the Talinga and Spring Gully facilities which was published on the Australia Pacific LNG website www.aplng.com.au/publications on 11 August this year. The results demonstrate that both water treatment facilities consistently and reliably treat CSG water to a standard which is safe for discharge into a source of public drinking water.

All releases of water are backed by a stringent water monitoring and reporting program, as part of licensing requirements. We test the water we treat at the facility on a daily basis as well as undertake weekly monitoring upstream and downstream in the broader Condamine River environment. Random and independent monitoring is also undertaken by the Department of Environment and Resource Management (DERM).

We regard reverse osmosis water treatment to supplement local flows in the Condamine River as the first step in working with landholders, communities and regulators to develop further opportunities for this water which may include broader agricultural and commercial use and, depending on technical trials and feasibility assessment, re-injection.

The elements and chemicals listed in the (NTN submission) are all within the normal parameters detailed in the Australian Drinking Water Guidelines and found in treated drinking water.

Marian Lloyd-Smith's submission, as a representative of the National Toxic Network, seeks to multiply out the parameters of Australian Drinking Water Guidelines (ADWG) against release volumes and licence timeframes.

While you can theoretically multiply release volumes by the parameters within ADWG guidelines over the total timeframe of the current licence, this is neither a realistic nor representative reflection of our licence conditions or quality of actual releases.

This is a hypothetical claim at best, and one that will mislead and cause unnecessary concern. If this claim had substance then a similar claim of 'dumping chemicals' could be levelled at every Municipal Water Supply Organisation in Australia.

I trust this information has helped to clarify Marion Lloyd-Smith's submission in reference to our Talinga operations.

Appendix 1: Codes of Practice and Standards that apply to Australia Pacific LNG's Drilling Completion activities

Australia Pacific LNG's drilling and completions activities must comply with:

1. **Requirements of government legislation and regulation**
2. **Requirements of Project approval conditions and environmental authorities.**
3. **Requirements of Origin's HSE Management Systems including mandatory requirements of the HSE directives.**
4. **Requirements of the Drilling Management System and procedures.**
5. **Requirements of the CSG Drilling & Completions Code of Practice including reference standards and guidelines.**

The following industry standards may be appropriate for the application of the CSG Drilling and Completions Code of Practice.

- Competency Standard for the Petroleum and Gas Drilling Industry (2007) – Version 2, January 2010
- API Recommended Practice 65-2, Isolating Potential Flow Zones During Well Construction
- API Guidance Document HF1, Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines
- API Recommended Practice 10D-2/ISO 10427-2, Recommended Practice for Centralizer Placement and Stop Collar Testing
- API Technical Report 10TR4, Technical Report on Considerations Regarding Selection of Centralizers for Primary Cementing Operations
- API Specification 5B, Specification for Threading, Gauging, and Thread Inspection of Casing, Tubing, and Line Pipe Threads
- API Specification 5CT/ISO 11960, Specification for Casing and Tubing
- API Specification 6A/ISO 10432, Specification for Wellhead and Christmas Tree Equipment
- API Specification 16A, Specification for Drill Through Equipment
- Code of Practice for coal seam gas wellhead emissions detection and reporting (DEEDI, 2011).

Petroleum tenure holders need to consider the following references, to manage well construction issues associated with the whole of life cycle requirements for CSG wells:

- API Recommended Practice 5A5/ISO 15463, Field Inspection of New Casing, Tubing, and Plain-end Drill Pipe
- API Recommended Practice 5B1, Gauging and Inspection of Casing, tubing and Line Pipe Threads
- API Recommended Practice 5C1, Recommended Practice for Care and Use of Casing and Tubing
- API Technical Report 5C3, Technical Report on Equations and Calculations for Casing, Tubing, and Line Pipe used as Casing or Tubing; and Performance Properties Tables for Casing and Tubing
- API Recommended Practice 5C5/ISO 13679, Recommended Practice on Procedures for Testing Casing and Tubing Connections
- API Recommended Practice 5C6, Welding Connections to Pipe
- API Recommended Practice 10B-5/ISO 10426-5, Recommended Practice on Determination of Shrinkage and Expansion of Well Cement Formulations at Atmospheric Pressure
- API Specification 10D/ISO 10427-1, Specification for Bow-Spring Casing Centralizers
- API Recommended Practice 10F/ISO 10427-3, Recommended Practice for Performance Testing of Cementing Float Equipment
- API Technical Report 10TR2, Shrinkage and Expansion in Oilwell Cements
- API Technical Report 10TR3, Temperatures for API Cement Operating Thickening Time Tests

- API Technical Report 10TR5, Technical Report on Methods for Testing of Solid and Rigid Centralizers
- API Specification 13A /ISO 13500, Specification for Drilling Fluid Materials
- API Recommended Practice 13B-1/ISO 10414-1, Recommended Practice for Field Testing Water-Based Drilling Fluids
- API Recommended Practice 13D, Recommended Practice on the Rheology and Hydraulics of Oil-well Drilling Fluids
- API Recommended Practice 53, Blowout Prevention Equipment Systems for Drilling Operations
- API Recommended Practice 54, Occupational Safety for Oil and Gas Well Drilling and Servicing Operations
- API Recommended Practice 59, Recommended Practice for Well Control Operations API Specification 16C, Choke and Kill Systems
- API Specification 16D, Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment
- API Specification 16RCD, Drill Through Equipment (Rotating Control Devices)
- API Specification 16ST, Coil Tubing Well Control Equipment Systems
- ANSI/API Specification 15LR, Low Pressure Fibreglass Line Pipe and Fittings
- ANSI/API Specification 15R, High Pressure Fibreglass Line Pipe
- ASTM D2996-01 (2007)e1 Standard Specification for Filament-Wound “Fibreglass” (Glass-Fibre-Reinforced Thermosetting-Resin) Pipe
- ASTM D2310 - 06 Standard Classification for Machine-Made “Fibreglass” (Glass-Fibre-Reinforced Thermosetting-Resin) Pipe
- ASTM D2517 – 06 Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings
- AS/NZS 1477-1999 PVC Pipes and Fittings for Pressure Applications
- AS 2634 – 1983 Chemical Plant Equipment – Made from Glass-Fibre Reinforced Plastics (GRP) Based on Thermosetting Resins
- ISO 1872-1: 1993, Polyethylene (PE) moulding and extrusion materials - Part 1: Designation system and basis for specifications

These standards and specifications must only be used if they do not contradict the mandatory requirements stipulated in this Code of Practice.

6. Codes and Standards Applicable to Onshore Drilling Operations in Australia

All equipment, systems and workmanship should comply with the latest copy of the following relevant Australian Codes and Standards, including but not limited to the following:

- Australian Standard AS1020 - Static Electricity
- Australian Standard AS1380 - Fibre Rope Slings
- Australian Standard AS1768 - Lightning Protection
- Australian Standard AS2187 - Explosives
- Australian Standard AS2430 - Hazardous Areas
- Australian Standard AS3000 - SAA Wiring Rules
- Australian Standard AS3008 Part 1 - Electrical Installations - Selection of Cables
- Australian Standard AS1680 - Rules for Lighting Interiors
- Australian Standard AS1136 - Low Voltage Switchgear and Control Gear Assemblies
- Australian Standard AS3190 - Approval and Test Specifications for Current Operated (core-balance) Earth Leakage Devices
- Australian Standard AS1668 - SAA Mechanical Ventilation for Acceptable Indoor Air Quality
- Australian Standard AS2380.1 - Electrical Equipment for Explosive Atmospheres Part 1: Explosive Protection Techniques - General Requirements

- Australian Standard AS2380.3 - Electrical Equipment for Explosive Atmospheres. Part 3: Explosive Protection Techniques - Pressurised Rooms and Enclosures
- Australian Standard AS2380.7 - Electrical Equipment for Explosive Atmospheres. Part 7: Explosive Protection Techniques - Intrinsic Safety
- Applicable Australian Hoisting, Lifting and Pressure Vessel Standards
- Australian Standard 60079 – Electrical apparatus for explosive gas atmospheres

Where no Australian Codes and Standards exist, then the materials, equipment and accessories should conform to the following standards and codes, where applicable:

- API RP 16E - Recommended Practice for Design of Control Systems for Drilling Well Control Equipment.
- API RP 500 - The Institute of Petroleum Safety Code Part 1
- API 610 - Centrifugal pumps and General Refining Service
- API RP 520 - Recommended Practice for Design and Installation of Pressure Relieving Systems
- ANSI / ASTM B31.3 - Chemical Plant and Petroleum Refinery Piping
- AISC - American Institute of Steelwork Construction
- API 8A - Drilling and Hoisting Equipment
- API 9 –Wire Ropes
- API 9A –Care of Wire Ropes
- API Spec 7 - Recommended Practice for Rotary Drilling
- NEMA ICS - 2 - 322 - AC Motor Control Centres 600v and Less
- EEMAC E 14-2 - Industrial Control and Systems Standard
- Applicable NACE standards
- API RP 7L – Procedures for Inspection, Maintenance, Repair and Remanufacture of Drilling Equipment
- API RP 8B – Procedure for Inspection, Maintenance, Repair and Remanufacture of Hoisting Equipment
- API Spec 8C – Specification for Drilling and Production Hoisting Equipment
- API RP 505 – Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class 1, Zone 0, Zone 1, Zone 2
- API HF1 - Hydraulic Fracturing Operations - Well Construction and Integrity Guidelines
- API RP 65 – Part 2 – Isolating Potential Flow Zones During Well Construction
- API Specification 10A/ISO 10426-1 - Specification for Cements and Materials for Well Cementing
- API RP 10B-2/ISO 10426-2 - Recommended Practice for Testing Well Cements
- API Recommended Practice 10D-2/ISO 10427-2 - Recommended Practice for Centralizer Placement and Stop Collar Testing
- IADC HSE Guidelines
- Plant Advisory Standard published in 2000 by the Division of Workplace Health and Safety, Department of Industrial Relations.

Based on Schedule 1 of Petroleum and Gas (Production and Safety) Regulation 2004 materials, equipment and accessories shall conform to the following standards and codes:

- ISO 10405 Petroleum and natural gas industries—casing and tubing (2000)
- ISO 10407 Petroleum and natural gas industries—care and use of drilling and production equipment; drill stem design and operating limits (1993)
- ISO 10414 Petroleum and natural gas industries—field testing of drilling fluids Part 1 Water-based fluids (2001); Part 2 Oil-based fluids (2002)
- ISO 10423 Petroleum and natural gas industries—drilling and production equipment—wellhead and christmas tree equipment (2003)
- ISO 10424 Petroleum and natural gas industries—rotary drilling equipment Part 1 Rotary drill stem elements (2004)
- ISO 10427 Petroleum and natural gas industries—casing centralizers Part 1 Bow-spring casing centralizers (2001); Part 2 Centralizer placement and stop-collar testing (2004); Part 3 Performance testing of cementing float equipment (2003)

- ISO 11960 Petroleum and natural gas industries—steel pipes for use as casing or tubing for wells (2001)
- ISO 11961 Petroleum and natural gas industries—steel pipes for use as drill pipe—specification (1996)
- ISO 13533 Petroleum and natural gas industries—drilling and production equipment—drill-through equipment (2001)
- ISO 13534 Petroleum and natural gas industries—drilling and production equipment—inspection, maintenance, repair and remanufacture of hoisting equipment (2000)
- ISO 13535 Petroleum and natural gas industries—drilling and production equipment—hoisting equipment (2000)
- ISO 13626 Petroleum and natural gas industries—drilling and production equipment—drilling and well-servicing structures (2003)
- ISO 13679 Petroleum and natural gas industries—procedures for testing casing and tubing connections (2002)
- ISO 14693 Petroleum and natural gas industries—drilling and well-servicing equipment (2003)
- ISO 15136 Downhole equipment for petroleum and natural gas industries—progressing cavity pump systems for artificial lift Part 1 Pumps (2001)
- ISO 15546 Petroleum and natural gas industries—aluminium alloy drill pipe (2002)

SENATE RURAL AFFAIRS AND TRANSPORT REFERENCES COMMITTEE

Inquiry into the management of the Murray Darling Basin

Public Hearing Friday, 9 September 2011

Questions Taken on Notice – Dart Energy Ltd

1. HANSARD, PG 20

Senator WATERS: You said you were a very active member of APPEA and they have commissioned a report by Worley Parsons into this very issue of greenhouse gas intensity of coal seam gas, but unfortunately they have not been forthcoming with that report. Are you able to source and provide to the committee a full copy of that report by Worley Parsons—not just the executive summary and not any version that has had alterations by APPEA or anyone else, but their full report?

Mr de Weijer: When you asked the question earlier, I was wondering if had I seen that report. Unless it has come in over the last two or three days, I have not, but I am more than happy to commit to check with APPEA to see where that report is.

Senator WATERS: Thank you, and provide it to us if you are able to. That would be great.

2. HANSARD, PG 21

Mr de Weijer: We talk about it as well. Our position on land access agreements is that we want to respect the landholders. If the landholders are comfortable in being transparent about their access agreement, that is perfectly fine with us.

Senator EDWARDS: So you are happy to provide a summary of those access agreements and the compensation—and a light to this committee?

Mr de Weijer: Providing that the landholders consent.

Senator EDWARDS: Of course.

Mr Needham: We cannot give out private information without permission.

Senator EDWARDS: I understand that. Given that we would provide anonymity for them, you are happy to provide that information?

Mr de Weijer: Yes.

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19 September, 2011

Ref: DRBO-11-025/Rdw:ce

Committee Secretary
Senate Standing Committee on Rural Affairs and Transport
PO Box 6100
Parliament House
Canberra ACT 2600
Australia

Via email: rat.sen@aph.gov.au

Dear Committee Secretary

Subject: Action Items Identified at Senate Hearing - 9 September, 2011

Dart Energy agreed to action a number of items following testifying at the inquiry last Friday, 9 September, 2011. They are as follows:

1. Worley Parson Report on Life Cycle Emissions

Commission requested Dart to ask APPEA if the above report could be shared with the Commission.

Dart followed up with APPEA who informed us that this report is "commercial-in-confidence" and that APPEA intends to commission another lifecycle greenhouse report that can be released.

2. Namoi Water Catchment Study

Commission requested Dart's position with regard to the Namoi Water Catchment Study.

APPEA has informed us that the Phase 2 report has now been released and that the next step is to identify what scenarios should be modeled

Attached is a map (refer Attachment 1) indicating where our tenements overlap with the Namoi catchment area. Due to the relatively small overlap and our very modest exploration activity programme in these areas, we do not expect that the study will impact our operations in a significant way.

3. Land Access Agreements

Commission requested Dart to provide land access information.

Dart will be issuing letters to our landholders next week asking them to give consent for us to release data from the land access agreements. A copy of the letter is attached (refer Attachment 2). In the letter we ask landholders to respond by 1 October 2011. We will compile and forward the data to you shortly after that date.

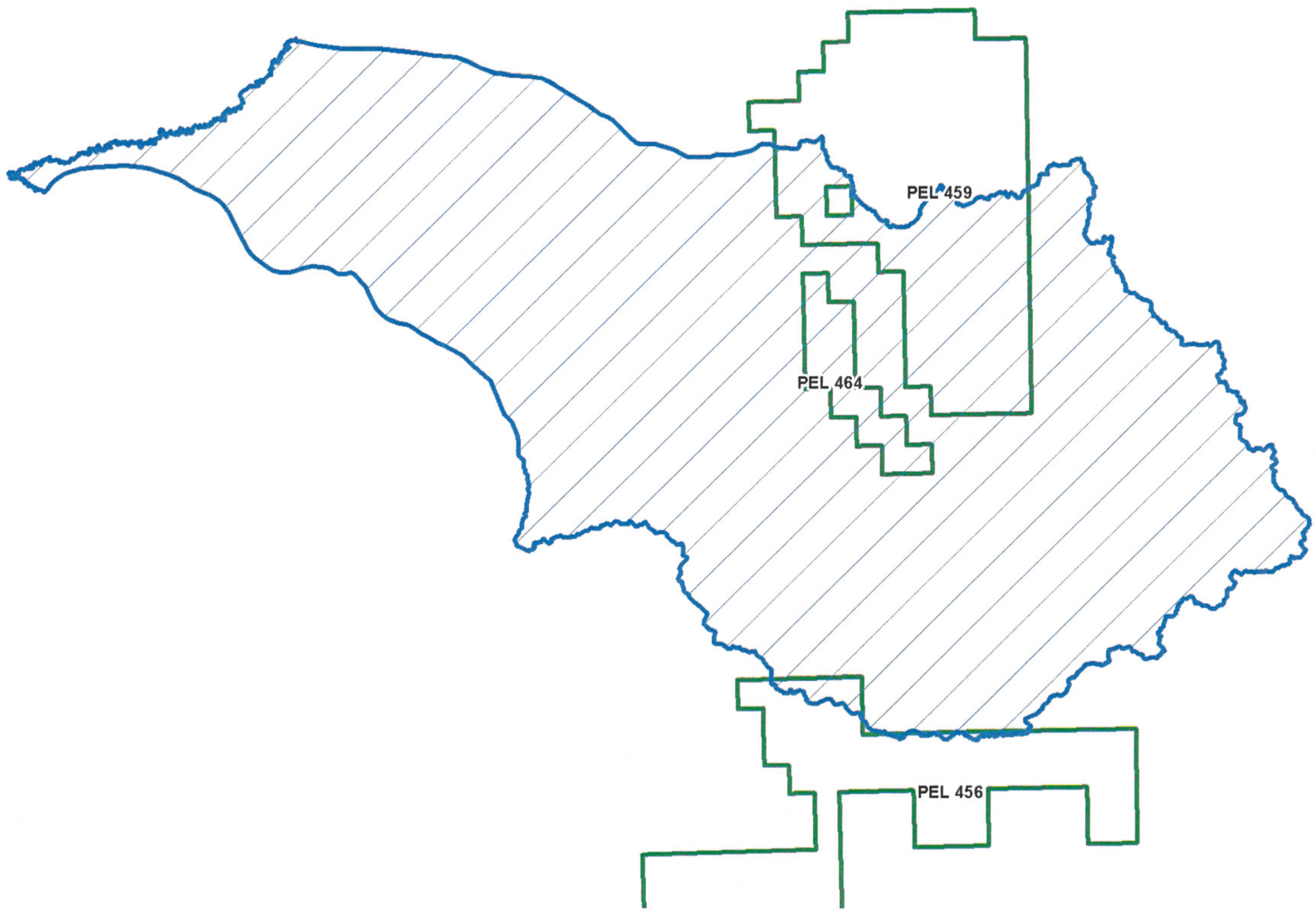
Please let me know if you require any further information.

Regards

Robbert de Weijer
Chief Executive Officer, Australia

Encl: *Attachment 1 - Namoi Catchment Area Map*
Attachment 2 - Copy of Landholder Letter

Attachment 1



DART ENERGY

Attachment 2

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ASX CODE DTE **ABN** 21 122 588 505

dartenergy.com.au

19 September, 2011

Ref: DRBO-11-024/Rdw:ce

<<Enter Address Here>>

Dear <<First Name>>

Dart Energy testified at the Senate Inquiry into the management of the Murray Darling Basin on Friday September 9th. During the session we were asked whether Dart Energy was willing to make a summary of the contents of Dart's land access agreements with relevant landowners available to the inquiry commission, led by Senator Bill Heffernan. Our response was that we were willing to do so but only with the consent of the relevant landowners. We would provide the information on an anonymous basis, i.e. the rough location would be mentioned but not the names of the landholders.

By means of this letter we request you provide your consent or otherwise by return email to Andrew Collins, External Relations Manager at acollins@dartcbm.com or by completing the below form and sending this to:

Dart Energy Ltd
GPO Box 3120
Brisbane QLD 4001

We would very much appreciate a **response by 1 October**. If no response is received by then we will assume that you are not willing to give consent to the information being released to the inquiry commission.

Regards

Robbert de Weijer
Chief Executive Officer, Australia

Please tick the appropriate box below

I herewith do ❑ / do not ❑ give consent for a summary of the contents of the land access agreement pertaining to my property to be released to the Inquiry.

Signed:

....

Date: ....

Name: ....
(Please print name)

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25 October 2011

Ref: DRBO-11-038/Rdw:ce

Committee Secretary
Senate Standing Committee on Rural Affairs and Transport
PO Box 6100
Parliament House
Canberra ACT 2600
Australia

Via email: rat.sen@aph.gov.au

Dear Committee Secretary

Re: Landholder Action Item Identified at Senate Hearing - 9 September 2011

I am writing in response to the request issued at the Murray Darling Basin Senate Inquiry held on 9 September 2011, for Dart Energy to provide details of Land Access Agreements with relevant landholders, including a summary of financial payments.

As advised, we were willing to do so but only with the consent of the relevant landholders and then providing the information on an anonymous basis. We wrote to all eleven of our landholders. Two landholders agreed to the request and we can now provide a summary of information for these landholders. The table below represents this summary which is accurate as at Friday 21 October. Please note that the rates below are representative for other access agreements under our operations.

		Land Access Compensation			**Additional Payments**			
Land-holder	**Type of Project**	**Upfront Compensation**	**Total Weekly Compensation (@$250/week)**	**Total Compensation (upfront + weekly)**	**Services Provided by Landholder**	**Legal Fees Reimbursed**	**Estimated Cost of Improvements**	**Estimated Total**
A	Exploration corehole	$5,000	$10,000*	$15,000	nil	$385.00	$50,000	**$65,385.00**
B	Exploration corehole	$5,000	$2,500	$7,500	$2,100	$1282.50	$17,100	**$27,982.50**

** extended weekly payments due to suspension of drilling*

I have also included a copy of our standard Landholder Access and Compensation Agreement. Our land access agreements are between the Landholder and Macquarie Energy Pty Ltd, which is the licence holder and subsidiary of Dart Energy.

Should you require further information please do not hesitate to contact myself or our External Relations Manager, Andrew Collins *(contact details are listed below)*.

Robbert de Weijer
Chief Executive Officer, Australia
Email: rdeweijer@dartcbm.com
Tel: (07) 3149 2126

Andrew Collins
External Relations Manager
Email: acollins@dartcbm.com
Tel: (02) 9146 6330

Yours sincerely

Robbert de Weijer
Chief Executive Officer, Australia

Encl: Attachment 1 - Standard Landholder Access and Compensation Agreement

Landholder Access and Compensation Agreement

between

Macquarie Energy Pty Limited (ABN 95 113 972 473)

and

[insert landholder]

Parties

Macquarie Energy	Macquarie Energy Pty Ltd ABN 95 113 972 473 (the Titleholder) of Suite 24.04, Level 24, MLC Centre, Sydney NSW 2000
Landholder	[insert landholder]

Background

A. The Landholder owns or is the registered lessee of the Land.

B. The Titleholder and Operator is Macquarie Energy Pty Ltd (ABN 95 113 972 473), and is the registered holder of the Petroleum Exploration Licence, which covers an area that includes the Land.

C. The Operator, on behalf of the Titleholder, wishes to enter the Land to carry out the Prospecting Operations in accordance with their rights and obligations under the Petroleum Exploration Licence and the Petroleum Legislation.

D. The purpose of this Agreement is to record the agreement between Macquarie Energy and the Landholder regarding access to the Land to carry out the Prospecting Operations and the compensation payable to the Landholder.

Agreement

1 Definitions

1.1 A term shown in the first column of the Agreement Specifics will have the meaning shown opposite it in the Agreement Specifics when used in this Agreement. That meaning may be extended by clause 1.2.

1.2 In this Agreement, unless the context requires otherwise:

Agreement Specifics means Schedule 1 to this Agreement.

Business Day means any day except for a Saturday, Sunday or a public holiday in New South Wales.

Compensation includes any compensation payable to the Landholder under clause 7.

Emergency means a period of time that, in the Titleholder's opinion, exists as a result of a threat to the integrity of the Titleholder' property on the Land, the health and safety of any person, the environment or to property on the Land.

Infrastructure means all equipment, plant and access required for the drilling, testing, fracture stimulation, operation, production and abandonment of boreholes within the Petroleum Exploration Licence installed or constructed by the Titleholder on the Land.

Operator means Macquarie Energy Pty Ltd (ABN 95 113 972 473).

Petroleum Exploration Licence includes any tenement applied for or granted in renewal or extension of it or in substitution for or modification of it in whole or in part or as of right under or as a consequence of the Petroleum Exploration Licence.

Petroleum Legislation means the *Petroleum (Onshore) Act 1991* (NSW).

Prospecting Operations includes:

(a) the transfer, establishment, use of and access to the Infrastructure;

(b) all works carried out in relation to the Infrastructure;

(c) unimpeded access to and from the Land for the purposes of discharging the Titleholder's rights and obligations under the Petroleum Exploration Licence and the Petroleum Legislation; and

(d) any other activity agreed with the Landholder in writing.

Borehole means an exploration borehole drilled as part of the Prospecting Operations.

Seismic means reflection seismic surveys acquired as part of the Prospecting Operations.

2 Scope of Agreement

The Landholder agrees that this Agreement constitutes an 'access arrangement' and a 'compensation agreement' for the purposes of the Petroleum Legislation.

3 Term

3.1 This Agreement will commence on the Commencement Date and will continue until the earlier of:

(a) the Landholder ceasing to own the Land;

(b) the Operator plugging, abandoning the Boreholes and rehabilitating the site to the reasonable satisfaction of the Landholder;

(c) the Petroleum Exploration Licence ceases to remain in force;

(d) the parties agreeing to terminate this Agreement.

3.2 The Titleholder may terminate this Agreement at any time upon giving one months' notice to the Landholder provided that the Titleholder have rehabilitated the site to the reasonable satisfaction of the Landholder.

4 Access

4.1 The Landholder agrees that the Titleholder may access the Land during the term of this Agreement as follows:

(a) the Titleholder and Operator may access the Land during the Access Hours to carry out the Prospecting Operations;

(b) the Titleholder and Operator may access the Land at any time to deal with an Emergency; and

(c) the Titleholder or Operator must give the Landholder at least two days' notice before entering the Land to start carrying out the Prospecting Operations.

4.2 If the Landholder leases or agrees to lease the surface of the Land to a tenant during the term of this Agreement, the Landholder must ensure that the tenant agrees that:

(a) the lease or agreement to lease is subject to the terms of access set out in this Agreement; and

(b) all Compensation will be payable directly to the Landholder and the Titleholder will not be liable to pay any additional amount to the tenant.

5 Conduct of Prospecting Operations

5.1 The Titleholder and Operator agree to use their reasonable endeavours to:

(a) locate roads and Infrastructure so as to minimise interference with the Landholder's farming and livestock operations; and

(b) minimise the noise from any Prospecting Operations conducted within the proximity of an inhabited residence on the Land.

5.2 The Landholder consents to the Prospecting Operations being carried out at the locations set out in Schedule 2, even if they are on land on which an improvement has been constructed or within 200m of their residence or within 50m of a garden, vineyard or orchard on the Land.

5.3 The Titleholder and Operator may, for the purpose of conducting the Prospecting Operations, construct or bring Infrastructure on to the Land and access that Infrastructure using existing roads on the Land as agreed with the Landholder and any new roads constructed by the Titleholder under this Agreement.

5.4 The Landholder acknowledges that all Infrastructure remains the property of the Operator irrespective of whether the Infrastructure is attached to the Land in a permanent fashion.

5.5 With the Landholder's agreement, the Operator may use water from the Landholder's surface and subsurface facilities in the drilling, completion and fracture stimulation operations of any Borehole and for drilling seismic shot holes.

5.6 During this Agreement, the Operator must repair to a condition as near as practicable to its original condition:

(a) any damage to the Land or any fence, building or other improvement on the Land;

(b) any material damage to an access road used by the Operator,

as soon as practicable after the damage is caused.

6 Obligations of Titleholder

In relation to the Prospecting Operations by the Titleholder on the Land, the Titleholder must, and must ensure that any third party authorised by it to use the Land will:

(a) carry out all such operations on the Land in a proper and workmanlike manner and so as to cause as little injury and disturbance as practicable to any land, livestock or property of the Landholder having regard to the nature of such operations;

(b) if required by the Titleholder and with the permission of the Landholder, erect gates on the Land and keep those gates in a stock proof condition;

(c) use all efforts to extend courtesies and respect the privacy of the Landholder;

(d) report to the Landholder any accidental injury or killing of livestock or damage to the property of the Landholder caused by the Titleholder;

(e) where possible, use the Land in a manner which, consistent with the exercise of the rights granted under the Petroleum Tenement, will minimise the disturbance of people and livestock in the surrounding area;

(f) leave all gates in the position found unless otherwise advised by the Landholder;

(g) not take timber, soil and water from the Land to an extent greater than is necessary for the purpose of the Prospecting Operations without the prior consent of the Landholder;

(h) take all precautions against the transportation of declared noxious weeds and seeds;

(i) take all such measures as may be reasonably practical to protect native flora and fauna;

(j) in relation to seismic activities, refrain from laying down fencing without permission from the Landholder, not remove water except from locations agreed by the Landholder and not set up camp within one kilometre of a stock watering point;

(k) not carry any firearms on the Land and neither bring dogs thereon or to hunt, shoot or fish on the Land without the prior consent of the Landholder;

(l) take all reasonable measures to prevent erosion from the Land and of the bed or banks of any stream or lake and the deposition of excavated material or eroded material in any lake, stream or watercourse;

(m) remove all rubbish, waste, lunch bags, cans or construction debris caused by its activities on the Land;

(n) comply with all statutory provisions which may be enforced from time to time in relation to bush fire damage or to restrictions on the lighting of fires in the open and properly extinguish all camp fires after use;

(o) take all reasonable precautions to prevent the outbreak of any fire and not burn any debris or rubbish without the prior consent of the Landholder;

(p) where the Titleholder open or break up the Land, as soon as practicable, and consistent with the requirements of the Prospecting Operations, restore the surface of the Land to its former condition so far as is practicable and consistent with the practice in the upstream oil and gas industry and its obligations under law;

(q) not to destroy, remove or clear trees, timber and scrub to an extent greater than is necessary having regard to the nature of the Prospecting Operations and where the consent of any government department or other agency is required prior to the destruction, removal or clearing of any trees, timber or scrub, the Titleholder must obtain that approval prior to commencing any destruction, removal or clearing;

(r) carry out all activities on the Land in accordance with all relevant Commonwealth, State and local government laws including the Petroleum Legislation; and

(s) to the extent reasonably possible, drive all vehicles at moderate to slow speed and on established tracks and roads and where there is any deterioration of those tracks or roads by the Titleholder, maintain all such tracks or roads to the original condition. The Landholder acknowledges that seismic activities follow grid patterns not related to established tracks and roads and that the Prospecting Operations will require access to areas of the Land without any established tracks and roads.

7 Compensation

7.1 The Titleholder agree to pay Compensation to the Landholder for any injurious affect to the Land caused by the Prospecting Operations in the manner and at the times set out in this clause.

7.2 If requested by the Landholder within 6 months of the Prospecting Operations being completed, the Titleholder agree to discuss with the Landholder whether further Compensation is payable in addition to the Compensation set out in the Agreement Specifics and to resolve that Compensation.

7.3 In addition to the upfront Compensation set out in the Agreement Specifics, the Titleholder agree to Compensate the Landholder as follows:

(a) if and to the extent that the Prospecting Operations directly cause loss or damage to the Landholder's livestock or facilities on the Land, the Titleholder must either:

(1) repair the damage caused; or

(2) reimburse the Landholder for the actual loss sustained by the Landholder (including crops lost or damaged, additional stock mustering costs and supervision and the Landholder' time in dealing with the Titleholder);

The Titleholder must consult with the Landholder about options set out in clauses (1) and (2) above but the final decision about whether (1) or (2) will be adopted shall lie with the Titleholder.

(b) the Titleholder will control, or will bear the Landholder’s reasonable costs of controlling, declared noxious weeds that grow on a Borehole site, on access roads and on any retained wellhead areas to the extent those weeds are attributable to the Prospecting Operations; and

(c) the Titleholder will reimburse the Landholder for any loss of income or extra costs by the Landholder in the ordinary course of its grazing and agricultural business arising directly from the Prospecting Operations, provided that the Landholder demonstrates to the Titleholder’s reasonable satisfaction the nature and amount of that loss or those costs.

7.4 The parties agree that the amount of Compensation payable by the Titleholder may be reduced by the value of any “in kind” compensation supplied to the Landholder.

7.5 The Compensation will be payable as follows:

(a) the upfront Compensation for the drilling of boreholes, as specified in the Agreement Specifics, is payable to the Landholder within 14 days of this Agreement being executed;

(b) ongoing Compensation, as specified in the Agreement Specifics, on a weekly basis during the period of drilling operations, which commences on arrival of the drilling rig at the site, and concludes when all equipment has vacated the site, and excludes the period of site rehabilitation;

(c) Compensation for the death of livestock, damage to crops or loss of income will be paid to the Landholder upon the Titleholder receiving from the Landholder a written advice as to the fair market value of the livestock or crop and information demonstrating to the Titleholder’s reasonable satisfaction the nature and amount of the loss of income.

(d) deferred compensation based on a line kilometre rate for the acquisition of seismic information. This will be determined after the line(s) have been completed and the distances accurately measured. The payment is to be made within 14 days of completion of the seismic program over the landowner's property.

7.6 If there is a material change in circumstances and the Landholder intends to apply to the Warden under the Petroleum Legislation for a review of the Compensation, the Landholder agrees to give the Titleholder written notice stating its intention to make the application and providing details of the application at least 14 days before making any such application.

7.7 The Compensation is in full and final satisfaction of all current and future liability of the Titleholder to pay compensation to the Landholder in respect of the Prospecting Operations and includes compensation for:

(a) damage to the surface of the Land, and damage to the crops, trees, grasses or other vegetation on the Land, or damage to buildings and improvements on the Land, being damage which has been caused by or which may arise from the Prospecting Operations;

(b) deprivation of the possession or use of the use of the surface of the Land or any part of the surface;

(c) severance of any part of the Land from other parts of the Land or from other land that the Landholder owns;

(d) surface rights of way and easements;

(e) destruction or loss of, or injury to, or disturbance of, or interference with, stock on the Land; and

(f) any damage consequential to any matter listed in clauses 7.7(a) to 7.7(e).

7.8 The Landholder agrees and acknowledges that:

(a) the Landholder represents all parties entitled to claim Compensation for the Prospecting Operations under the Petroleum Legislation;

(b) the Compensation is not related to the discovery or non-discovery of oil and/or gas reserves within the Land; and

(c) except as set out in this clause 7, the Titleholder have no other obligation to pay compensation to the Landholder either under the Petroleum Legislation or otherwise.

8 GST

8.1 The Compensation does not include GST. If GST applies to the Compensation, the Titleholder will:

(a) increase the Compensation amount payable to allow for GST; and

(b) issue a recipient created tax invoice on behalf of the Landholder.

8.2 Words defined in the GST Law (as that term is defined in *A New Tax System (Goods and Services Tax) Act* 1999 (Cth)) have the same meaning when used in this clause 8.

9 Landholder's Indemnity

9.1 Subject to clause 9.2, the Landholder indemnifies and will keep indemnified the Titleholder and Operator against:

(a) any damage to the Infrastructure; and

(b) any claim, demand, cost or liability made against or suffered or incurred by any person,

that is caused by or which arises directly from the negligent acts or omissions of the Landholder or its employees or agents.

9.2 This indemnity set out in clause 9.1 does not apply to any claim arising out of accidents or events beyond the reasonable control of the Landholder.

9.3 Provided the Landholder takes reasonable care, the Titleholder release the Landholder from all liability for damage to Infrastructure caused by the Landholder.

9.4 Any Compensation paid to the Landholder under this Agreement will be deemed to include compensation for the occupier of any Land and the Landholder will indemnify the Titleholder against any claim by the occupier of the Land arising in respect of the loss, damage or expense for which compensation has been paid.

10 Titleholder’s Indemnity

10.1 Subject to clause 10.4, the Titleholder indemnify and will keep indemnified the Landholder against any claim, demand, cost or liability made against or suffered or incurred by the Landholder which result directly from:

(a) injuries sustained by any person;

(b) the death of any person;

(c) damage to any property, whether of a third party or of the Landholder,

due to or caused by the negligent acts or omissions of the Titleholder or their employees, agents or contractors. This indemnity also extends to third parties unknown who engage in misconduct while performing activities on behalf of the Titleholder under this agreement.

10.2 Subject to clause 10.4, the Titleholder will indemnify the Landholder against any damage to crops, timber, pasture land, livestock, improvements or other property caused by the Titleholder’s employees, agents, contractors and subcontractors.

10.3 Subject to clause 10.3, the Titleholder will indemnify the Landholder against any loss or damage to equipment, including vehicles or plant, bought onto site by the Titleholder or any of its employees, agents or contractors except where the loss or damage is caused by an act or omission of the Landholder.

10.4 The indemnities set out in clauses 10.1 and 10.2 do not apply in respect of any claim, demand, cost or liability to which the compensation provisions under clause 7 apply.

11 Assignment

11.1 The Landholder must not assign its rights and obligations under this Agreement without the prior written consent of the Titleholder. The Titleholder must not unreasonably withhold consent.

11.2 The Landholder may transfer all or part of its interest in the Land to another party without the Titleholder’s consent provided that the Landholder advises the Titleholder of the transfer.

12 Disputes

If there is a dispute between the parties about any matter under this Agreement, the dispute must be referred to an appropriately qualified expert selected by agreement or, if the parties cannot agree on an appropriately qualified expert, the procedure set out in the Petroleum Legislation will apply to resolve the dispute.

13 Force Majeure

The Titleholder are not liable for a breach of this Agreement to the extent that the breach is caused by circumstances outside the Titleholder’s direct control so long as the Titleholder:

(a) notify the Landholder of the circumstances as soon as reasonably practicable after they arise;

(b) try to remedy those circumstances quickly; and

(c) notify the Landholder when those circumstances have ceased.

14 Notices

14.1 Notices must be in writing and in English and may be given by an authorised representative of the sender.

14.2 Notices may be given to a person by leaving it in their mailbox at the person's address last notified to the other party, sending it by pre-paid mail to the person's address last notified to the other party or by sending it by facsimile to the person's facsimile number last notified to the other party.

14.3 Notice is deemed to be received by a person when left at the person's address, if sent by pre-paid mail, on the third Business Day after posting or, if sent by facsimile, at the time and on the day shown in a sending machine's transmission report that indicates that the whole facsimile was sent to the person's facsimile number last notified (or, if the day shown is not a Business Day or if the time shown is after 5.00pm in the person's time zone, at 9.00am on the next Business Day).

15 Confidentiality

15.1 Subject to clause 15.2, each party agrees to keep this Agreement and related negotiations and documents confidential and agrees not to disclose any of its terms without first obtaining the other party’s prior written consent, which consent must not be unreasonably withheld.

15.2 A party may make the following disclosures without the consent of the other party:

(a) disclosures to the party’s legal advisers and consultants;

(b) disclosures to a potential purchaser of the Land or an interest in the Petroleum Exploration Licence, provided that the potential purchaser agrees to keep this Agreement confidential on the same terms as this clause 15;

(c) disclosures required by law, including disclosure to any stock exchange;

(d) disclosures ordered by any court, tribunal or authority.

16 General

16.1 The Titleholder may exercise its rights under this Agreement by itself or through its authorised employees, agents, servants and contractors, including the Operator.

16.2 If the Landholder comprises more than one person, each of those persons is jointly and severally liable under this Agreement and, if the Titleholder comprise more than one person, each of those persons is severally but not jointly liable under this Agreement.

16.3 This Agreement is governed by the law of New South Wales and each party irrevocably submits to the exclusive jurisdiction of the Courts of that State.

16.4 This Agreement constitutes the entire agreement between the Titleholder and the Landholder in relation to its subject matter and supersedes any prior understanding or agreement between them.

16.5 This Agreement may only be amended by an order of a Warden's court or with the prior written consent of the parties.

16.6 This Agreement may be signed in any number of counterparts with the same effect as if the signatures to each counterpart were on the same instrument.

17 Interpretation

In this Agreement unless the context otherwise requires:

(a) singular includes plural and plural includes singular;

(b) a reference to a party includes that party's personal representatives, successors and permitted assigns;

(c) a reference to a schedule or annexure is a reference to a schedule or annexure of this Agreement;

(d) a provision will be read down to the extent necessary to be valid and, if it cannot be read down to that extent, it must be severed;

(e) a reference to a statute includes all statutes amending, consolidating or replacing the statute and to all regulations, direction and orders made under it;

(f) headings do not affect interpretation; and

(g) a provision must not be construed against a party only because that party put the provisions forward.

Execution

EXECUTED as an agreement.

SIGNED for and on behalf of)
Macquarie Energy Pty Ltd in the presence of:)

_______________________________________ _______________________________________

Witness

Signatory
Name:
Title:

SIGNED for and on behalf of)
[insert landholder]
in the presence of:)

_______________________________________ _______________________________________

Witness

[Landholder]

____

Name (please print)

_______________________________________ _______________________________________

Witness

[Landholder]

____

Name (please print)

Each landholder must have a space to sign

Schedule 1 - Agreement Specifics

Date of Agreement	/ /
Landholder	[insert landholder]
Land	[insert Lot/DP] [insert address]
Titleholder	Macquarie Energy Pty Ltd (ABN 95 113 972 473)
Petroleum Exploration Licence	[insert licence number]
Commencement Date	Upon Execution of this Agreement
Prospecting Operations	▪ Drilling of a borehole at the location proposed in Schedule 2 ▪ Establishing, maintaining, testing and monitoring the Boreholes and all ancillary operations ▪ All associated road works and fencing required to allow the Titleholder continued access to the Boreholes ▪ Acquisition of seismic surveys • Rehabilitation of the Land pursuant to the Petroleum Legislation.
Access Hours	Please **tick and initial**, either: ☐ Monday–Sunday: 6am to 6pm: Drilling rig not to be operated outside the hours of 6am to 6pm except in the case of Emergency or with Landholder's consent ***or*** ☐ Monday-Sunday, 6am to 6am: 24 Hr access No restriction on hours during which drilling rig may be operated.
Compensation	Upfront compensation, payable within 14 days of this Agreement being executed: ▪ $5000 per borehole drilled (7.5(a)) Ongoing compensation, payable within 14 days of the completion of drilling operations: • $250 per week (7.5(b)) Additional compensation as set out in clause 7 of the Agreement.

Schedule 2 – Proposed Location of Prospecting Operations

MAP

Location of proposed exploration borehole site.

Schedule 3 – Preferred Payment Options

Please indicate your preferred payment method for Compensation as described in Schedule 1, and provide relevant details.

For Individuals

☐ Electronic Funds Transfer

Account Name: ____

Bank: ____

Account No.: ____

BSB No.: ____

☐ Cheque

Payable to (name): ____

For Companies

For Compensation payable to a company or trading name, please send an invoice for the amount to:

Macquarie Energy Pty Ltd
ABN 95 113 972 473
Suite 24.04, Level 24, MLC Centre,
Sydney NSW 2000

Please ensure that your ABN is supplied and to include GST (if appropriate).

☐ Electronic Funds Transfer

Account Name: ____

Bank: ____

Account No.: ____

BSB No.: ____

☐ Cheque

Payable to (name): ____

PRIVACY NOTE: all details supplied will be kept in confidence and used solely for the purposes of this Agreement.

SENATE RURAL AFFAIRS AND TRANSPORT REFERENCES COMMITTEE

Inquiry into the management of the Murray Darling Basin

Public Hearing Friday, 9 September 2011

Questions Taken on Notice – Doctors for the Environment

1. HANSARD, PG 36-37

Senator WATERS: I have a final question, which is a bit detailed. You mentioned the Australian Drinking Water Guidelines. I am from Queensland and I know the Queensland government has just commenced, after delaying for eight months, its so-called ban on BTEX. It is not a ban; it is an upper limit. They say that it is in keeping with the drinking water guidelines. I have not gone back to check the drinking water guidelines so I wonder if you can answer, off the top of your head, or take on notice what those drinking water guidelines are. For benzene, the Queensland regulations say one part per billion, for ethyl benzene 80 parts per billion, for toluene 180 parts per billion, for xylene 75 parts per billion. Can you answer either now or get back to us on whether that is indeed consistent with the Australian Drinking Water Guidelines or does it exceed those?

Dr Carey: Off the top of my head I can tell you about benzene and I can take the others on notice.

Doctors for the Environment Australia
www.dea.org.au

SENATE RURAL AFFAIRS AND TRANSPORT
REFERENCES COMMITTEE

Inquiry into the management of the Murray Darling Basin

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1. HANSARD, PG 36-37

Response to question on notice

The Australian Drinking Water Guidelines (ADWG) are available from the NHMRC website. They are undergoing a rolling revision process.
http://www.nhmrc.gov.au/_files_nhmrc/publications/attachments/eh34_adwg_11_06.pdf.
It should be noted that aesthetic guidelines may be lower than health guidelines.
Below are some excerpts copied from the ADWG in relation to the question on notice.

Fact Sheets **Physical and Chemical Characterisitics**
Australian Drinking Water Guidelines

Benzene

GUIDELINE

No safe concentration for benzene in drinking water can be confidently set. However, for practical purposes the concentration should be less than 0.001 mg/L, which is the limit of determination

Fact Sheets **Physical and Chemical Characterisitics**
Australian Drinking Water Guidelines

Ethylbenzene

GUIDELINE

Based on aesthetic considerations (taste and odour), the concentration of ethylbenzene in drinking water should not exceed 0.003 mg/L.
Ethylbenzene would not be a health concern unless the concentration exceeded 0.3 mg/L.

Fact Sheets **Physical and Chemical Characterisitics**
Australian Drinking Water Guidelines

Toluene

GUIDELINE

Based on aesthetic considerations (taste and odour), the concentration of toluene in drinking water should not exceed 0.025 mg/L.
Toluene would not be a health concern unless the concentration exceeded 0.8 mg/L.

Fact Sheets **Physical and Chemical Characterisitics**
Australian Drinking Water Guidelines

Xylenes

GUIDELINE

Based on aesthetic considerations (taste and odour), the concentration of xylenes in drinking water should not exceed 0.02 mg/L.
Xylenes would not be a health concern unless the concentration exceeded 0.6 mg/L.

Additional Information – Doctors for the Environment
9 September 2011 – MDB: CSG Inquiry

I attach 3 references in relation to requests for further information from senators during the evidence recently given by DEA in relation to coal seam mining (Hansard transcript p34-35).

Ref 1 relates to radium arising from coal-bed methane mining operations:

"Water coproduced with methane ......must be disposed of or used for beneficial purpose:
The choice depends in large part on the composition of the water. Important composition information should include TDS (often equated to the amount of "salt" a water contains), pH, concentrations of dissolved metals and radium, and the type and amounts of dissolved organic constituents."

Ref 2 relates to radium and other radioactive substances and provides more detailed information.

NORM = Naturally occurring radioactive materials.

See particularly p11: "The activities described in Section 3.1 could also lead to an increased availability of the radionuclides for potential human exposures. In some cases, the enhancement in concentration of NORM may be insignificant or relatively small, but a large amount of NORM could be disrupted from their natural state. This is most apparent in the case of the enhanced potential for human exposure as a result of metal or mineral mining. Mining activities often involve extraction of a given valuable fraction of a very large ore body, leaving the remainder as a residue. In this case, the concentrations of the NORM may not be significantly enhanced in the mining residues (e.g. tailings and gangue), but very large amounts of NORM are more available for release into the biosphere than they were in the undisturbed natural state. "

p12: "The radionuclides tend to exist in equilibrium in rock formations. The formation water, often a brine with low sulphate concentration, preferentially dissolves radium relative to the parents uranium and thorium. Thus, radium and its progeny are present in larger concentrations than uranium and thorium in the water.As noted above, the fraction of water in the oil–gas–water mixture tends to increase during the time in which a reservoir is exploited. Thus, NORM in extraction and separation facilities for a specific reservoir becomes more prevalent over time."

p16: " the process residues containing technologically enhanced NORM associated with the oil and gas industry occur in the form of scales, sludges and films. There are also additional NORM containing residues or contaminated soils from the water discharges produced. The amounts and characteristics of these residues vary considerably in different installations .Data for oil wells in the United States of America suggest that an average of roughly 100 t of scale per well is generated each year. ....It is known that the amount of scale increases as a well ages due to the increasing ratio of water to oil and in some cases the introduction of salt water into the formation to enhance recovery."

This report can be found at: http://www-pub.iaea.org/books/

Ref 3 is the reference from Duke University which notes" In aquifers overlying the Marcellus and Utica shale formations of northeastern Pennsylvania and upstate New York, we document systematic evidence for methane contamination of drinking water associated with shale gas extraction."

I add one additional reference from the US government in relation to effects of petroleum compounds (question from Chair p38 transcript)

http://www.atsdr.cdc.gov/toxfaqs/tf.asp?id=423&tid=75

Please do not hesitate to contact me should you require further information.

Kind regards

Dr Marion Carey

USGS
science for a changing world

Water Produced with Coal-Bed Methane

Introduction

Natural gas produced from coal beds (coal-bed methane, CBM) accounts for about 7.5 percent of the total natural gas production in the United States. Along with this gas, water is also brought to the surface. The amount of water produced from most CBM wells is relatively high compared to conventional natural gas wells because coal beds contain many fractures and pores that can contain and transmit large volumes of water. In some areas, coal beds may function as regional or local aquifers and important sources for ground water. The water in coal beds contributes to pressure in the reservoir that keeps methane gas adsorbed to the surface of the coal. This water must be removed by pumping in order to lower the pressure in the reservoir and stimulate desorption of methane from the coal (fig. 1). Over time, volumes of pumped water typically decrease and the production of gas increases as coal beds near the well bore are dewatered.

The need to decrease CO_2 emissions favors the increased use of natural gas as an alternative to coal. The contribution of CBM to total natural gas production in the United States is expected to increase in the foreseeable future (Nelson, 1999). Estimates of the amount of recoverable CBM have increased from about 90 trillion cubic feet (TCF) 10 years ago to about 141 TCF, spurred by advances in technology, exploration, and production (Nelson, 1999). As the number of CBM wells increases, the amount of water produced will also increase. Reliable data on the volume and composition of associated water will be needed so that States and communities can make informed decisions on CBM development. Most data on CBM waters have been gathered at two historically large production areas, the San Juan Basin in Colorado and New Mexico (sparse data) and the Black Warrior Basin in Alabama (extensive data). Rapid development in basins with limited data on CBM waters—i.e., the Powder River Basin in Wyoming and Montana—is currently a concern of producers; land owners; Federal, State, and local agencies; coal mining companies; and Native Americans.

Volumes and Compositions of CBM Water

As shown in table 1, the amount of water produced, as well as the ratio of water to gas, varies widely among basins with CBM production. Causes of variations include the duration of CBM production in the basin, original depositional environment, depth of burial, and type of coal. Relatively recent regulations concerning disposal and withdrawal of produced water have led to more accurate reporting of water data. Volume data for produced water from specific coal beds has the potential to provide information on exploration and production of CBM. Compositional data is commonly limited to the major dissolved ion species in water (cations and anions), whereas information on trace metals and isotopic composition is sparse.

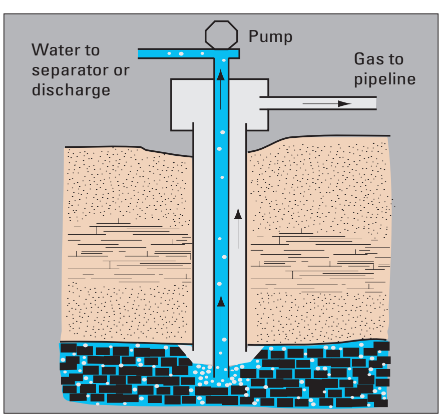


Figure 1. Simplified illustration of a coal-bed methane production well.

Table 1. Water production in some major coal-bed-methane-producing basins.

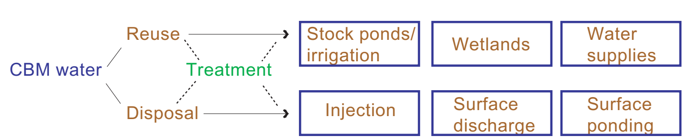
[Bbl, barrel (42 gallons); MCF, thousand cubic feet; No., Number; Avg., Average; disch., discharge. Data for Black Warrior Basin from Alabama State Oil and Gas Board as of 5/00; data for Powder River Basin from Wyoming Oil and Gas Commission as of 5/00; data for Raton and San Juan Basins from Colorado and New Mexico Oil and Gas Commissions as of 2/00; data for Uinta Basin from Utah Division of Oil and Gas as of 6/00]

Basin	State	No. of wells	Avg. water production (Bbl/day/well)	Water/gas ratio (Bbl/MCF)	Primary disposal method
Black Warrior	Ala.	2,917	58	0.55	Surface disch.
Powder River	Wyo., Mont.	2,737	400	2.75	Surface disch.
Raton	Colo.	459	266	1.34	Injection
San Juan	Colo., N. Mex.	3,089	25	0.031	Injection
Uinta	Utah	393	215	0.42	Injection

Generally, dissolved ions in water coproduced with CBM contain mainly sodium (Na), bicarbonate (HCO_3), and chloride (Cl). The composition is controlled in great part by the association of the waters with a gas phase containing varying amounts of carbon dioxide (CO_2) and methane. The bicarbonate component potentially limits the amount of calcium (Ca) and magnesium (Mg) through the precipitation of carbonate minerals. CBM waters are relatively low in sulfate (SO_4) because the chemical conditions in coal beds favor the conversion of SO_4 to sulfide. The sulfide is removed as a gas or as a precipitate. The total dissolved solids (TDS) of CBM water ranges from fresh (200 mg/L or parts per million) to saline (170,000 mg/L) and varies among and within basins. For comparison, the recommended TDS limit for potable water is 500 mg/L, and for beneficial use such as stock ponds or irrigation, the limit is 1,000–2,000 mg/L. Average seawater has a TDS of about 35,000 mg/L. The TDS of the water is dependent upon the depth of the coal beds, the composition of the rocks surrounding the coal beds, the amount of time the rock and water react, and the origin of the water entering the coal beds. Trace-element concentrations in CBM water are commonly low (<1 mg/L) as are volatile organic compounds (Gas Research Institute, 1995; Rice, 2000). In general, most CBM water is of better quality than waters produced from conventional oil and gas wells.

Fate of CBM Water

Water coproduced with methane is not reinjected into the producing formation to enhance recovery as it is in many oil fields. Instead, it must be disposed of or used for beneficial purpose:



The choice depends in large part on the composition of the water. Important composition information should include TDS (often equated to the amount of "salt" a water contains), pH, concentrations of dissolved metals and radium, and the type and amounts of dissolved organic constituents. If, with minor to no treatment, the water is of sufficient quality, it may be used with caution to supplement area water supplies. This water must meet requirements under several Federal and State regulations, including the Clean Water Act, the Safe Drinking Water Act, and the Resource Conservation and Recovery Act. If the water does not meet Federal and State standards for reuse, or if the cost of treatment is excessive, the water is disposed of by injection into a compatible subsurface formation or by surface discharge. Disposal of CBM water is also regulated by Federal and State agencies and must meet criteria for each type of disposal. For example, subsurface injection requires compatibility studies of the proposed injection formation and the water that is injected, whereas discharge to surface streams must meet daily effluent limits on constituents such as chlorides along with other criteria. For any CBM field, the cost of handling coproduced water varies from a few cents per barrel to more than a dollar per barrel and can add significantly to the cost of gas production. In some areas, the volumes of water produced and the cost of handling may prohibit development of the resource.

USGS Studies of CBM-Produced Water

The U.S. Geological Survey (USGS) has ongoing studies designed to provide information on the composition and volumes of CBM water in some of the most active areas of production in the United States. Data obtained on CBM waters provides information on the heterogeneity of the CBM reservoir, the potential flow paths in the reservoir, the source and evolution of the water, and the quality of the water prior to disposal or reuse. The USGS Energy Resources Team is conducting multidisciplinary studies in the Uinta and Powder River Basins that include sampling waters coproduced with CBM (fig. 2). These studies combine investigations of regional geology and hydrology as well as reservoir-specific studies such as coal fracture orientation, coal composition, gas composition and isotopic values, methane desorption, and water composition and isotopic values. Researchers from the USGS, Bureau of Land Management, Bureau of Indian Affairs, State agencies, and private companies are cooperating in an effort to provide a better understanding of CBM resources and associated water.

Figure 2. USGS chemist prepares to sample water from the wellhead of a coal-bed methane well. Wellhead sampling and on-site sample preservation and analysis are critical to obtaining good quality compositional and isotopic data. Many parameters, such as pH, alkalinity, and trace-metal content, change rapidly once the water is removed from the well.

CBM water studies include sampling wells throughout a field as well as analyzing the volumes of water that are produced. Analyses include major, minor, and trace constituents, including arsenic (As), selenium (Se), copper (Cu), cadmium (Cd), lead (Pb), molybdenum (Mo), chromium (Cr), mercury (Hg), and zinc (Zn) (fig. 3). The major anions (Cl^-, SO_4^{2-}, and HCO_3^-) are measured as well as selected other constituents, such as ammonia and total organic carbon. Isotopic analyses of the samples for deuterium, oxygen, and carbon provide data to help determine the origin of the water and its solutes as well as the compositional evolution of the water. Volumes of water produced from a CBM field are analyzed to determine trends in production that may be related to reservoir parameters such as permeability. In some areas of CBM development, USGS Water Resources District Offices are cooperating with State and Federal agencies to perform targeted studies such as measuring concentrations of selenium in wetlands and dating waters.

Average Water Composition

Uinta Basin (Ferron CBM, Utah) 1

Field	TDS (mg/L)	Cl (mg/L)	HCO_3 (mg/L)	Br / Cl
Buzzard Bench	11000	2300	8500	0.0063
Drunkards Wash	8900	2500	5500	0.0032
Helper State	26000	14000	5200	0.0013

Powder River Basin (Wyoming) 2

	CBM (µg/L)	DWS (µg/L)		CBM (µg/L)	DWS (µg/L)
Arsenic	<3	50	Manganese	32	50
Barium	620	2000	Mercury	<0.3	2
Chromium	<2	100	Selenium	<2	50

Figure 3. Concentrations of selected components in CBM water from three fields in the Ferron CBM area, Utah, and from 47 wells in Wyoming. TDS, total dissolved solids; DWS, drinking water standards. 1, Rice (1999); 2, Rice (2000).

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Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing

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Directional drilling and hydraulic-fracturing technologies are dramatically increasing natural-gas extraction. In aquifers overlying the Marcellus and Utica shale formations of northeastern Pennsylvania and upstate New York, we document systematic evidence for methane contamination of drinking water associated with shale-gas extraction. In active gas-extraction areas (one or more gas wells within 1 km), average and maximum methane concentrations in drinking-water wells increased with proximity to the nearest gas well and were 19.2 and 64 mg CH_4 L^{-1} (n 26), a potential explosion hazard; in contrast, dissolved methane samples in neighboring nonextraction sites (no gas wells within 1 km) within similar geologic formations and hydrogeologic regimes averaged only 1.1 mg L^{-1} ($P < 0.05$; n 34). Average $\delta^{13}C$ CH_4 values of dissolved methane in shallow groundwater were significantly less negative for active than for nonactive sites (37 ± 7‰ and 54 ± 11‰, respectively; $P < 0.0001$). These $\delta^{13}C$ CH_4 data, coupled with the ratios of methane-to-higher-chain hydrocarbons, and $\delta^{2}H$ CH_4 values, are consistent with deeper thermogenic methane sources such as the Marcellus and Utica shales at the active sites and matched gas geochemistry from gas wells nearby. In contrast, lower-concentration samples from shallow groundwater at nonactive sites had isotopic signatures reflecting a more biogenic or mixed biogenic/thermogenic methane source. We found no evidence for contamination of drinking-water samples with deep saline brines or fracturing fluids. We conclude that greater stewardship, data, and—possibly—regulation are needed to ensure the sustainable future of shale-gas extraction and to improve public confidence in its use.

groundwater | organic rich shale | isotopes | formation waters | water chemistry

Increases in natural gas extraction are being driven by rising energy demands, mandates for cleaner burning fuels, and the economics of energy use (1 5). Directional drilling and hydraulic fracturing technologies are allowing expanded natural gas extraction from organic rich shales in the United States and elsewhere (2, 3). Accompanying the benefits of such extraction (6, 7) are public concerns about drinking water contamination from drilling and hydraulic fracturing that are ubiquitous but lack a strong scientific foundation. In this paper, we evaluate the potential impacts associated with gas well drilling and fracturing on shallow groundwater systems of the Catskill and Lockhaven formations that overlie the Marcellus Shale in Pennsylvania and the Genesee Group that overlies the Utica Shale in New York (Figs. 1 and 2 and Fig. S1). Our results show evidence for methane contamination of shallow drinking water systems in at least three areas of the region and suggest important environmental risks accompanying shale gas exploration worldwide.

The drilling of organic rich shales, typically of Upper Devonian to Ordovician age, in Pennsylvania, New York, and elsewhere in the Appalachian Basin is spreading rapidly, raising concerns for impacts on water resources (8, 9). In Susquehanna County, Pennsylvania alone, approved gas well permits in the Marcellus formation increased 27 fold from 2007 to 2009 (10).

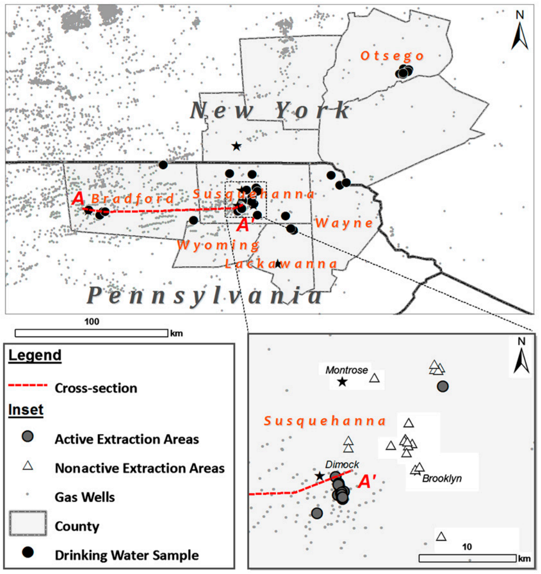

Fig. 1. Map of drilling operations and well water sampling locations in Pennsylvania and New York. The star represents the location of Binghamton, New York. (*Inset*) A close up in Susquehanna County, Pennsylvania, showing areas of active (closed circles) or nonactive (open triangles) extraction. A drinking water well is classified as being in an active extraction area if a gas well is within 1 km (see *Methods*). Note that drilling has already spread to the area around Brooklyn, Pennsylvania, primarily a nonactive location at the time of our sampling (see inset). The stars in the inset represent the towns of Dimock, Brooklyn, and Montrose, Pennsylvania.

Concerns for impacts to groundwater resources are based on (i) fluid (water and gas) flow and discharge to shallow aquifers due to the high pressure of the injected fracturing fluids in the gas wells (10); (ii) the toxicity and radioactivity of produced water from a mixture of fracturing fluids and deep saline formation waters that may discharge to the environment (11); (iii) the potential explosion and asphyxiation hazard of natural gas; and (iv) the large number of private wells in rural areas that rely on shallow groundwater for household and agricultural use up to one million wells in Pennsylvania alone that are typically unregulated and untested (8, 9, 12). In this study, we analyzed groundwater from 68 private water wells from 36 to 190 m deep in

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The authors declare no conflict of interest.

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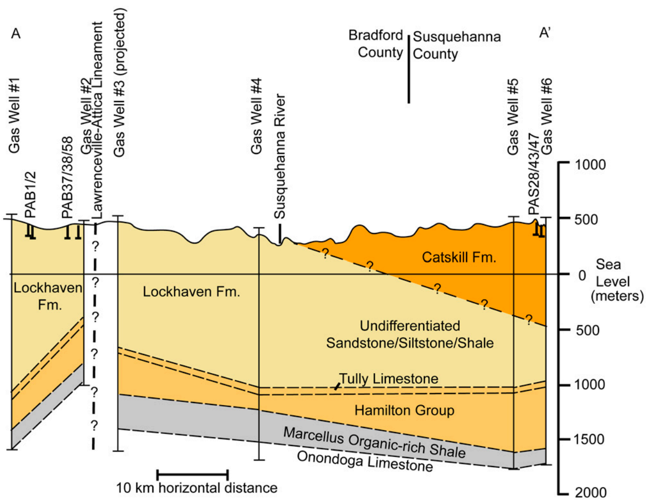

Fig. 2. Geologic cross section of Bradford and western Susquehanna Coun ties created from gas well log data provided by the Pennsylvania Department of Conservation and Natural Resources. The approximate location of the Law renceville Attica Lineament is taken from Alexander et al. (34). The Ordovician Utica organic rich shale (not depicted in the figure) underlies the Middle Devonian Marcellus at approximately 3,500 m below the ground surface.

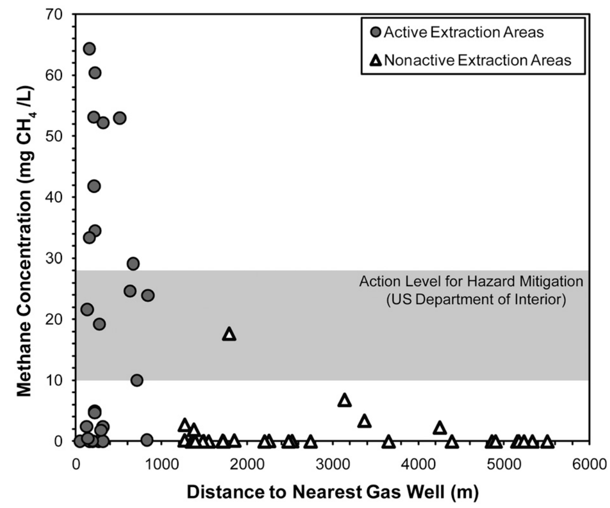

Fig. 3. Methane concentrations (milligrams of CH_4 L ^{1}) as a function of dis tance to the nearest gas well from active (closed circles) and nonactive (open triangles) drilling areas. Note that the distance estimate is an upper limit and does not take into account the direction or extent of horizontal drilling un derground, which would decrease the estimated distances to some extraction activities. The precise locations of natural gas wells were obtained from the Pennsylvania Department of Environmental Protection and Pennsylvania Spatial Data Access databases (ref. 35; accessed Sept. 24, 2010).

northeast Pennsylvania (Catskill and Lockhaven formations) and upstate New York (Genesee formation) (see Figs. 1 and 2 and *SI Text*), including measurements of dissolved salts, water isotopes (^{18}O and ^{2}H), and isotopes of dissolved constituents (carbon, boron, and radium). Of the 68 wells, 60 were also analyzed for dissolved gas concentrations of methane and higher chain hydro carbons and for carbon and hydrogen isotope ratios of methane. Although dissolved methane in drinking water is not currently classified as a health hazard for ingestion, it is an asphyxiant in enclosed spaces and an explosion and fire hazard (8). This study seeks to evaluate the potential impact of gas drilling and hydrau lic fracturing on shallow groundwater quality by comparing areas that are currently exploited for gas (defined as active one or more gas wells within 1 km) to those that are not currently asso ciated with gas drilling (nonactive; no gas wells within 1 km), many of which are slated for drilling in the near future.

Results and Discussion

Methane concentrations were detected generally in 51 of 60 drinking water wells (85%) across the region, regardless of gas industry operations, but concentrations were substantially higher closer to natural gas wells (Fig. 3). Methane concentrations were 17 times higher on average (19.2 mg CH_4 L^{-1}) in shallow wells from active drilling and extraction areas than in wells from nonactive areas (1.1 mg L^{-1} on average; $P < 0.05$; Fig. 3 and Table 1). The *average* methane concentration in shallow ground water in active drilling areas fell within the defined action level (10 28 mg L^{-1}) for hazard mitigation recommended by the US Office of the Interior (13), and our maximum observed value of 64 mg L^{-1} is well above this hazard level (Fig. 3). Understanding the origin of this methane, whether it is shallower biogenic or deeper thermogenic gas, is therefore important for identifying the source of contamination in shallow groundwater systems.

The $\delta^{13}C$ CH_4 and $\delta^{2}H$ CH_4 values and the ratio of methane to higher chain hydrocarbons (ethane, propane, and butane) can ty pically be used to differentiate shallower, biologically derived methane from deeper physically derived thermogenic methane (14). Values of $\delta^{13}C$ CH_4 less negative than approximately −50‰ are indicative of deeper thermogenic methane, whereas values more negative than −64‰ are strongly indicative of microbial methane (14). Likewise, $\delta^{2}H$ CH_4 values more negative than about −175‰, particularly when combined with low $\delta^{13}C$ CH_4 values, often represent a purer biogenic methane origin (14).

The average $\delta^{13}C$ CH_4 value in shallow groundwater in active drilling areas was -37 ± 7‰, consistent with a deeper thermo genic methane source. In contrast, groundwater from nonactive areas in the same aquifers had much lower methane concentra tions and significantly lower $\delta^{13}C$ CH_4 values (average of -54 ± 11‰; $P < 0.0001$; Fig. 4 and Table 1). Both our $\delta^{13}C$ CH_4 data and $\delta^{2}H$ CH_4 data (see Fig. S2) are consistent with a deeper ther mogenic methane source at the active sites and a more biogenic or mixed methane source for the lower concentration samples from nonactive sites (based on the definition of Schoell, ref. 14).

Because ethane and propane are generally not coproduced during microbial methanogenesis, the presence of higher chain hydrocarbons at relatively low methane to ethane ratios (less than approximately 100) is often used as another indicator of deeper thermogenic gas (14, 15). Ethane and other higher chain hydrocarbons were detected in only 3 of 34 drinking water wells from nonactive drilling sites. In contrast, ethane was detected in 21 of 26 drinking water wells in active drilling sites. Additionally, propane and butane were detected (>0.001 mol %) in eight and two well samples, respectively, from active drilling areas but in no wells from nonactive areas.

Further evidence for the difference between methane from water wells near active drilling sites and neighboring nonactive sites is the relationship of methane concentration to $\delta^{13}C$ CH_4 values (Fig. 4*A*) and the ratios of methane to higher chain hydro

Table 1. Mean values ± standard deviation **of methane concentrations (as milligrams of CH_4 L^{-1}) and carbon isotope composition in methane in shallow groundwater $\delta^{13}C$ CH_4 sorted by aquifers and proximity to gas wells (active vs. nonactive)**

Water source, *n*	milligrams CH_4 L ^{1}	$\delta^{13}C$ CH_4, ‰
Nonactive Catskill, 5	1.9 ± 6.3	52.5 ± 7.5
Active Catskill, 13	26.8 ± 30.3	33.5 ± 3.5
Nonactive Genesee, 8	1.5 ± 3.0	57.5 ± 9.5
Active Genesee, 1	0.3	34.1
Active Lockhaven, 7	50.4 ± 36.1	40.7 ± 6.7
Total active wells, 21	19.2	37 ± 7
Total nonactive wells, 13	1.1	54 ± 11

The variable *n* refers to the number of samples.

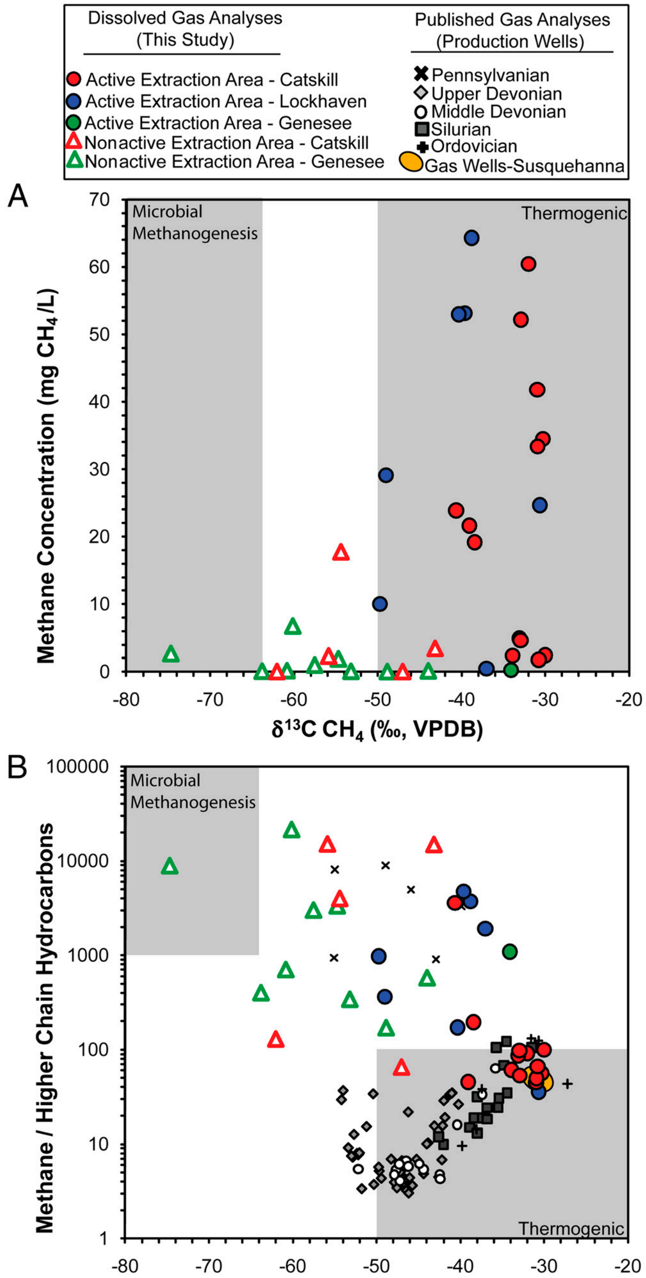

Fig. 4. (*A*) Methane concentrations in groundwater versus the carbon isotope values of methane. The nonactive and active data depicted in Fig. 3 are subdivided based on the host aquifer to illustrate that the methane concentrations and δ^{13}C values increase with proximity to natural gas well drilling regardless of aquifer formation. Gray areas represent the typical range of thermogenic and biogenic methane taken from Osborn and Mcin tosh (18). VPDB, Vienna Pee Dee belemnite. (*B*) Bernard plot (15) of the ratio of methane to higher chain hydrocarbons versus the δ^{13}C of methane. The smaller symbols in grayscale are from published gas well samples from gas production across the region (16 18). These data generally plot along a tra jectory related to reservoir age and thermal maturity (Upper Devonian through Ordovician; see text for additional details). The gas well data in the orange ovals are from gas wells in our study area in Susquehanna County, Pennsylvania (data from Pennsylvania Department of Environmental Protec tion). Gray areas represent typical ranges of thermogenic and biogenic methane (data from Osborn and McIntosh, ref. 18).

carbons versus δ^{13}C CH_4 (Fig. 4*B*). Methane concentrations not only increased in proximity to gas wells (Fig. 3), the accompany ing δ^{13}C CH_4 values also reflected an increasingly thermogenic methane source (Fig. 4*A*).

Using a Bernard plot (15) for analysis (Fig. 4*B*), the enriched δ^{13}C CH_4 (approximately $> -50‰$) values accompanied by low ratios of methane to higher chain hydrocarbons (less than approximately 100) in drinking water wells also suggest that dis solved gas is more thermogenic at active than at nonactive sites (Fig. 4*B*). For instance, 12 dissolved gas samples at active drilling sites fell along a regional gas trajectory that increases with reser voir age and thermal maturity of organic matter, with samples from Susquehanna County, Pennsylvania specifically matching natural gas geochemistry from local gas wells (Fig. 4*B*, orange oval). These 12 samples and local natural gas samples are con sistent with gas sourced from thermally mature organic matter of Middle Devonian and older depositional ages often found in Marcellus Shale from approximately 2,000 m below the surface in the northern Appalachian Basin (14 19) (Fig. 4*B*). In contrast, none of the methane samples from nonactive drilling areas fell upon this trajectory (Fig. 4*B*); eight dissolved gas samples in Fig. 4*B* from active drilling areas and all of the values from non active areas may instead be interpreted as mixed biogenic/ thermogenic gas (18) or, as Laughrey and Baldassare (17) pro posed for their Pennsylvanian gas data (Fig. 4*B*), the early migra tion of wet thermogenic gases with low δ^{13}C CH_4 values and high methane to higher chain hydrocarbon ratios. One data point from a nonactive area in New York fell squarely in the para meters of a strictly biogenic source as defined by Schoell (14) (Fig. 4*B*, upper left corner).

Carbon isotopes of dissolved inorganic carbon (δ^{13}C DIC $>$ $+10‰$) and the positive correlation of δ^2H of water and δ^2H of methane have been used as strong indicators of microbial methane, further constraining the source of methane in shallow groundwater (depth less than 550 m) (18, 20). Our δ^{13}C DIC values were fairly negative and show no association with the δ^{13}C CH_4 values (Fig. S3), which is not what would be expected if methanogenesis were occurring locally in the shallow aquifers. Instead, the δ^{13}C DIC values from the shallow aquifers plot within a narrow range typical for shallow recharge waters, with the dissolution of CO_2 produced by respiration as water passes downward through the soil critical zone. Importantly, these values do not indicate extensive microbial methanogenesis or sulfate reduction. The data do suggest gas phase transport of methane upward to the shallow groundwater zones sampled for this study ($<$190 m) and dissolution into shallow recharge waters locally. Additionally, there was no positive correlation between the δ^2H values of methane and δ^2H of water (Fig. S4), indicating that microbial methane derived in this shallow zone is negligible. Overall, the combined gas and formation water results indicate that thermogenic gas from thermally mature organic matter of Middle Devonian and older depositional ages is the most likely source of the high methane concentrations observed in the shal low water wells from active extraction sites.

A different potential source of shallow groundwater contam ination associated with gas drilling and hydraulic fracturing is the introduction of hypersaline formation brines and/or fractur ing fluids. The average depth range of drinking water wells in northeastern Pennsylvania is from 60 to 90 m (12), making the average vertical separation between drinking water wells and the Marcellus Shale in our study area between approximately 900 and 1,800 m (Fig. 2). The research area, however, is located in tectonically active areas with mapped faults, earthquakes, and lineament features (Fig. 2 and Fig. S1). The Marcellus formation also contains two major sets of joints (21) that could be conduits for directed pressurized fluid flow. Typical fracturing activities in the Marcellus involve the injection of approximately 13 19 mil lion liters of water per well (22) at pressures of up to 69,000 kPa. The majority of this fracturing water typically stays underground and could in principle displace deep formation water upward into shallow aquifers. Such deep formation waters often have high concentrations of total dissolved solids >250,000 mg L^{-1}, trace toxic elements, (18), and naturally occurring radioactive materials, with activities as high as 16,000 picocuries per liter (1 pCi L^{-1} = 0.037 becquerels per liter) for ^{226}Ra compared to a drinking water standard of 5 pCi L^{-1} for combined ^{226}Ra and ^{226}Ra (23).

We evaluated the hydrochemistry of our 68 drinking water wells and compared these data to historical data of 124 wells in the Catskill and Lockhaven aquifers (24, 25). We used three types of indicators for potential mixing with brines and/or saline fracturing fluids: (*i*) major inorganic chemicals; (*ii*) stable isotope signatures of water ($\delta^{18}O$, $\delta^{2}H$); and (*iii*) isotopes of dissolved constituents ($\delta^{13}C$ DIC, $\delta^{11}B$, and ^{226}Ra). Based on our data (Table 2), we found no evidence for contamination of the shallow wells near active drilling sites from deep brines and/or fracturing fluids. All of the Na^{+}, Cl^{-}, Ca^{2+}, and DIC concentrations in wells from active drilling areas were consistent with the baseline historical data, and none of the shallow wells from active drilling areas had either chloride concentrations >60 mg L^{-1} or Na Ca Cl compositions that mirrored deeper formation waters (Table 2). Furthermore, the mean isotopic values of $\delta^{18}O$, $\delta^{2}H$, $\delta^{13}C$ DIC, $\delta^{11}B$, and ^{226}Ra in active and nonactive areas were indistinguishable. The ^{226}Ra values were consistent with available historical data (25), and the composition of $\delta^{18}O$ and $\delta^{2}H$ in the well water appeared to be of modern meteoric origin for Pennsylvania (26) (Table 2 and Fig. S5). In sum, the geochemical and isotopic features for water we measured in the shallow wells from both active and nonactive areas are consistent with historical data and inconsistent with contamination from mixing Marcellus Shale formation water or saline fracturing fluids (Table 2).

There are at least three possible mechanisms for fluid migration into the shallow drinking water aquifers that could help explain the increased methane concentrations we observed near gas wells (Fig. 3). The first is physical displacement of gas rich deep solutions from the target formation. Given the lithostatic and hydrostatic pressures for 1 2 km of overlying geological strata, and our results that appear to rule out the rapid movement of deep brines to near the surface, we believe that this mechanism is unlikely. A second mechanism is leaky gas well casings (e.g., refs. 27 and 28). Such leaks could occur at hundreds of meters underground, with methane passing laterally and vertically through fracture systems. The third mechanism is that the process of hydraulic fracturing generates new fractures or enlarges existing ones above the target shale formation, increasing the connectivity of the fracture system. The reduced pressure following the fracturing activities could release methane in solution, leading to methane exsolving rapidly from solution (29), allowing methane gas to potentially migrate upward through the fracture system.

Methane migration through the 1 to 2 km thick geological formations that overlie the Marcellus and Utica shales is less likely as a mechanism for methane contamination than leaky well casings, but might be possible due to both the extensive fracture systems reported for these formations and the many older, uncased wells drilled and abandoned over the last century and a half in Pennsylvania and New York. The hydraulic conductivity in the overlying Catskill and Lockhaven aquifers is controlled by a secondary fracture system (30), with several major faults and lineaments in the research area (Fig. 2 and Fig. S1). Consequently, the high methane concentrations with distinct positive $\delta^{13}C$ CH_4 and $\delta^{2}H$ CH_4 values in the shallow groundwater from active areas could in principle reflect the transport of a deep methane source associated with gas drilling and hydraulic fracturing activities. In contrast, the low level methane migration to the surface groundwater aquifers, as observed in the nonactive areas, is likely a natural phenomenon (e.g., ref. 31). Previous studies have shown that naturally occurring methane in shallow aquifers is typically associated with a relatively strong biogenic signature indicated by depleted $\delta^{13}C$ CH_4 and $\delta^{2}H$ CH_4 compositions (32) coupled with high ratios of methane to higher chain hydrocarbons (33), as we observed in Fig. 4*B*. Several models have been developed to explain the relatively common phenomenon of rapid vertical transport of gases (Rn, CH_4, and CO_2) from depth to the surface (e.g., ref. 31), including pressure driven continuous gas phase flow through dry or water saturated fractures and density driven buoyancy of gas microbubbles in aquifers and water filled fractures (31). More research is needed across this and other regions to determine the mechanism(s) controlling the higher methane concentrations we observed.

Based on our groundwater results and the litigious nature of shale gas extraction, we believe that long term, coordinated sampling and monitoring of industry and private homeowners is needed. Compared to other forms of fossil fuel extraction, hydraulic fracturing is relatively poorly regulated at the federal level. Fracturing wastes are not regulated as a hazardous waste under the Resource Conservation and Recovery Act, fracturing wells are not covered under the Safe Drinking Water Act, and only recently has the Environmental Protection Agency asked fracturing

Table 2. Comparisons of selected major ions and isotopic results in drinking-water wells from this study to data available on the same formations (Catskill and Lockhaven) in previous studies (24, 25) and to underlying brines throughout the Appalachian Basin (18)

	Active		Nonactive		Previous studies (background)		
	Lockhaven formation $N = 8$	Catskill formation $N = 25$	Catskill formation $N = 22$	Genesee group $N = 12$	Lockhaven formation (25) $N = 45$	Catskill formation (24) $N = 79$	Appalachian brines (18, 23) $N = 21$
Alkalinity as HCO_3,							
mg L^{-1}	285 ± 36	157 ± 56	127 ± 53	158 ± 56	209 ± 77	133 ± 61	150 ± 171
mM	[4.7 ± 0.6]	[2.6 ± 0.9]	[2.1 ± 0.9]	[2.6 ± 0.9]	[3.4 ± 1.3]	[2.2 ± 1.0]	[2.5 ± 2.8]
Sodium, mg L^{-1}	87 ± 22	23 ± 30	17 ± 25	29 ± 23	100 ± 312	21 ± 37	33,000 ± 11,000
Chloride, mg L^{-1}	25 ± 17	11 ± 12	17 ± 40	9 ± 19	132 ± 550	13 ± 42	92,000 ± 32,000
Calcium, mg L^{-1}	22 ± 12	31 ± 13	27 ± 9	26 ± 5	49 ± 39	29 ± 11	16,000 ± 7,000
Boron, µg L^{-1}	412 ± 156	93 ± 167	42 ± 93	200 ± 130	NA	NA	3,700 ± 3,500
$\delta^{11}B$ ‰	27 ± 4	22 ± 6	23 ± 6	26 ± 6	NA	NA	39 ± 6
^{226}Ra, pCi L^{-1}	0.24 ± 0.2	0.16 ± 0.15	0.17 ± 0.14	0.2 ± 0.15	0.56 ± 0.74	NA	6,600 ± 5,600
$\delta^{2}H$, ‰, VSMOW	66 ± 5	64 ± 3	68 ± 6	76 ± 5	NA	NA	41 ± 6
$\delta^{18}O$, ‰, VSMOW	10 ± 1	10 ± 0.5	11 ± 1	12 ± 1	NA	NA	5 ± 1

Some data for the active Genesee Group and nonactive Lockhaven Formation are not included because of insufficient sample sizes (NA). Values represent means ±1 standard deviation. NA, not available.

N values for $\delta^{11}B$ ‰ analysis are 8, 10, 3, 6, and 5 for active Lockhaven, active Catskill, nonactive Genesee, nonactive Catskill, and brine, respectively. *N* values for ^{226}Ra are 6, 7, 3, 10, 5, and 13 for active Lockhaven, active Catskill, nonactive Genesee, nonactive Catskill, background Lockhaven, and brine, respectively. $\delta^{11}B$ ‰ normalized to National Institute of Standards and Technology Standard Reference Material 951. $\delta^{2}H$ and $\delta^{18}O$ normalized to Vienna Standard Mean Ocean Water (VSMOW).

firms to voluntarily report a list of the constituents in the fracturing fluids based on the Emergency Planning and Community Right to Know Act. More research is also needed on the mechanism of methane contamination, the potential health consequences of methane, and establishment of baseline methane data in other locations. We believe that systematic and independent data on groundwater quality, including dissolved gas concentrations and isotopic compositions, should be collected before drilling operations begin in a region, as is already done in some states. Ideally, these data should be made available for public analysis, recognizing the privacy concerns that accompany this issue. Such baseline data would improve environmental safety, scientific knowledge, and public confidence. Similarly, long term monitoring of groundwater and surface methane emissions during and after extraction would clarify the extent of problems and help identify the mechanisms behind them. Greater stewardship, knowledge, and possibly regulation are needed to ensure the sustainable future of shale gas extraction.

Methods

A total of 68 drinking water samples were collected in Pennsylvania and New York from bedrock aquifers (Lockhaven, 8; Catskill, 47; and Genesee, 13) that overlie the Marcellus or Utica shale formations (Fig. S1). Wells were purged to remove stagnant water, then monitored for pH, electrical conductance, and temperature until stable values were recorded. Samples were collected "upstream" of any treatment systems, as close to the water well as possible, and preserved in accordance with procedures detailed in *SI Methods*. Dissolved gas samples were analyzed at Isotech Laboratories and water chemical and isotope (O, H, B, C, Ra) compositions were measured at Duke University (see *SI Methods* for analytical details).

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ENVIRONMENTAL SCIENCES

SENATE RURAL AFFAIRS AND TRANSPORT REFERENCES COMMITTEE

Inquiry into the management of the Murray Darling Basin

Public Hearing Friday, 9 September 2011

Questions Taken on Notice – NSW Department of Trade and Investment, Regional Infrastructure and Services

1. HANSARD, PG 62

Mr Paterson: The final policy position in relation to the agricultural impact statements is subject to consultation by the government at the present time. The final decisions in relation to its design and implementation have not been taken but there is a very significant reference group that is looking at all of these elements at the present time. I think the next meeting of the reference group is next week.

CHAIR: Can you give us the details of the reference group?

Mr Paterson: Happy to, on notice, Senator.