**S1** Supporting Information: Modeling the relative GHG emissions of conventional and shale gas production

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Supporting information is listed under the titles and subheadings of the original article and comprises 22 pages, 5 tables, 14 figures, and 28 references:

## S1 METHODOLOGY – COMPARING CONVENTIONAL AND SHALE GAS

### S1.1 Global warming potential

GHG emissions were calculated using2007 IPCC AR4 factors for 100-year global warming potential: 1, 25 and 298 for CO2, CH4 and N2O respectively. Some authors (notably Howarth[1]) have used 20-year global warming potential in addition to 100-year factors. The case that life cycles should be compared on the basis of their -year warming potential has not been widely accepted and use of 100-year potentials are mandated in U.S., Canadian and European legislation.

In this article, the fraction of total GHGs originating from methane is given at every stage, making it possible to derive GHGs using 20-year GWPs if desired.

### S1.2 Allocation of emissions to gas and co-products

A gas production project may have multiple products: not only gas but also condensate, ethane and LPG. In order to calculate the WtW emissions intensity of a gas pathway, it is necessary to divide the total emissions between the sales gas and other co-products. A guiding principle is that products ought not to be burdened with emissions from processes that they did not undergo.

For example, in upstream gas production:

- Some processes affect only gas, for example, export gas compression. Other co-products should not carry this burden.
- Some processes only affect the co-products, for example, stabilization of condensate or fractionation of LPG. The sales gas should not carry this burden.
- Some processes directly affect both gas and co-products. Gas and condensate emerge from the same well and therefore the emissions of well drilling, water pumping, gathering compressors, etc. must be shared between gas and condensate.
- Some processes indirectly affect both gas and co-products - overheads to the whole project such as waste water treatment, for example.

Emissions were allocated to co-products in proportion to their energy content. Dry sales gas accounted for 89.7% of the total energy produced (after allowing for fuel gas consumption) and was allocated 87.6% of emissions.

## S2 CONSTRUCTING THE MODEL

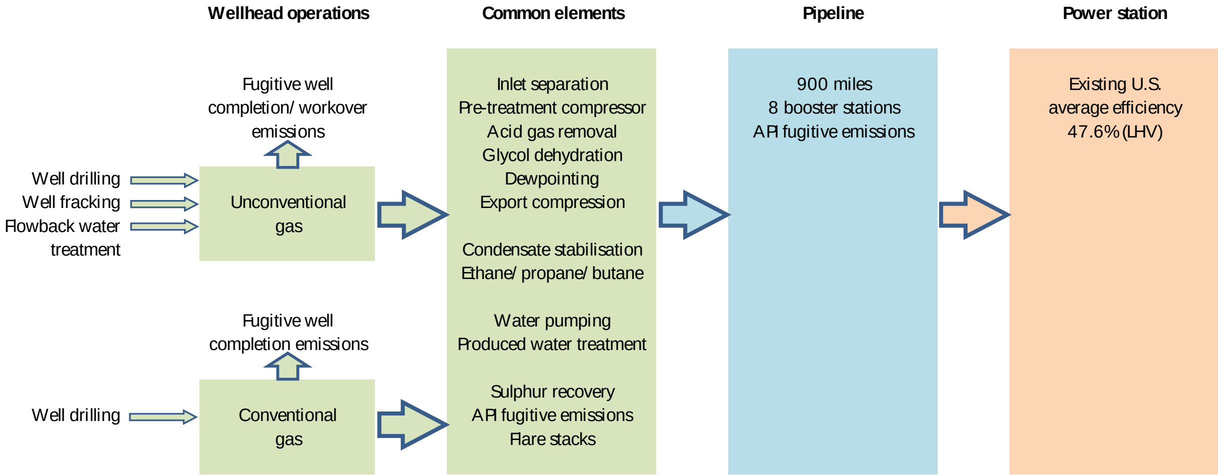


**Figure 1:** Simplified well-to-wire (WtW) pathway

### S2.1 Model gas composition

Data from the 2011 EPA Inventory Report[2] show that there is no systematic variation in the CO2 content of conventional and unconventional gas wells. The data show an almost complete overlap, with both types of gas ranging from nearly zero to more than 7% as shown in **Table S1**. A single gas composition was therefore used to model both conventional and unconventional production.

**Table S1: U.S. Production Sector CO2 Content in Natural Gas by NEMS Region and Natural Gas Well type**

| **NEMS region** | 1 **NE** | 2 **MC** | 3 **GC** | 4 **SW** | 5 **RM** | 6 **WC** | **Lower 48** |
|---|---|---|---|---|---|---|---|
| Co vention l | 0.92 | 0.79% | 2.1 % | 3.81% | 7.95% | 0.16% | 3.41% |
| Unconventional | 7.42% | 0.31% | 0.23% | none | 0.64% | none | 4.83% |
| All types | 3.04% | 0.79% | 2.17% | 3.81% | 7.58% | 0.16% | 3.45% |
| % U.S. production | 5% | 21% | 14% | 32% | 28% | 1% | 100% |

The following information was used to derive a model gas composition that can be taken as typical of the U.S. average natural gas:

- EIA 2011 Energy Outlook predicts that NGL (condensate and ethane/propane/butane fractionation) make up 11.8% of dry NG production by energy[3];
- EPA 2011 Inventory Report (Table A-131) shows that average U.S. well gas contains 3.45% $CO_2$[2];
- EPA/GRI 1996 fugitives study estimates 77.8%$CH_4$ in well gas, 87.0% in gas pre-treatment, and 93.4% pipeline gas[4];
- U.S. Geological Survey data for 2008 show that 1310 kilotonnes of sulphur was recovered from natural gas[5]. EIA 2011 Energy Outlook reports 20.29 Tcf produced in 2008[3], therefore $H_2S$ = 0.17%mol of sales gas, say 0.2% of well gas;
- EIA Annual Energy Review estimates the heating value of dry natural gas to be 1027 BTU/scf (HHV)[6]. The formulation must therefore include some inert gases ($CO_2$ and nitrogen) to achieve this low value.
- Maximum 2% $CO_2$ and 10 ppm $H_2S$ content in sales gas for pipelines.

Not all the above constraints could be met exactly.

**Table S2: Model gas composition**

| Composition | | Well gas | Sales gas |
|---|---|---|---|
| Water | (%mol) | 0.00 | 0.00 |
| Nitrogen | (%mol) | 0.90 | 0.98 |
| $CO_2$ | (%mol) | 3.50 | 2.00 |
| $H_2S$ | (%mol) | 0.20 | 0.00 |
| Methane | (%mol) | 87.00 | 91.28 |
| Ethane | (%mol) | 4.80 | 4.15 |
| Propane | (%mol) | 2.50 | 1.45 |
| i-butane | (%mol) | 0.40 | 0.11 |
| n-butane | (%mol) | 0.40 | 0.03 |
| i-pentane | (%mol) | 0.15 | 0.01 |
| n-pentane | (%mol) | 0.15 | 0.00 |
| TOTAL | | 100 | 100 |
| LHV | ($MJ/m^3$) | 35.96 | 34.92 |
| HHV | ($MJ/m^3$) | 39.79 | 38.70 |
| HHV | (BTU/scf) | 1068 | 1039 |

Natural gas liquids (condensate and ethane/propane/butane fractionation) = 11.6% of sales gas by energy.

The amount of water produced with the gas can vary greatly from one formation to another. 2004 data from NETL[7] showed an average water-gas ratio (WGR) of 0.436 bbl/mcf for conventional gas.

Water production from unconventional gas varies according to the source of the gas. For tight sands, a value of 0.17 bbl/mcf was quoted. Shale gas was quite dry at 0.001 bbl/mcf. Coal bed methane averaged 0.52 bbl/mcf, with Powder River as high a 1.67 bbl/mcf.

For this model, a value of 0.4 was used for both conventional and unconventional production, which is conservative for shale gas.

Wellhead pressure and temperature were assumed to be 40 bar and 30°C (580 psig and 86°F).

### S2.2 Gas treatment - common elements

Once gas has been produced from the well, there is no systematic difference in gas treatment between conventional and unconventional gas production. A common gas treatment was applied:

- Well water pumping, desalination at 0.5 kWh/bbl, and export;
- Inlet separation to produce condensate, with condensate stabilisation and export;
- Compression from wellhead pressure to 80 bar before treatment;
- Acid gas removal with 50%MDEA/50%water amine solution to remove H2S and reduce the CO2 content to the 2% permitted in pipelines;
- Glycol dehydration (TEG) to remove water vapour;
- Dewpointing (JT-LTX) and fractionation to extract ethane, propane and butane liquids;
- Re-compression to 80 bar for sales gas export.

The following processes are included:

- Claus sulphur recovery unit;
- Fugitive emissions (using API Compendium facility-level factors for onshore production and treatment);
- Flare stack purge and pilot gas combustion.

The following processes may occur at various locations but have been excluded from this model:

- Trace heating in the gathering system;
- Re-injection of H2S or CO2;
- Mercaptan or carbonyl sulphide (COS) removal.

Excluding processes from the common gas treatment model tends to increase the difference between conventional and unconventional gas and is therefore a conservative approach.

The common elements represent the U.S. industry average, and are not necessarily representative of any individual gas production project. Many projects will have little or no gas treatment, whereas some projects will have more than the average.

### S2.3 Transmission pipeline

It was assumed that gas was transported 900 miles (1440 km) from gas field to power plant: the same assumption used in a recent NETL study of the emissions intensity of Natural Gas Combined Cycle (NGCC) powergen[8].

EIA reports that the average compressor station on the interstate pipeline network consists of four compressors of 3590 HP each (total 10.7 MW) pumping gas at a rate of 748 mmscf/day (21.1 Msm$^3$/d). U.S. pipelines typically operate at a pressure of 1000 psi (69 bar) and the average pressure ramp up at each station is 250 psi (17 bar)[9].

It was assumed that compressor stations are spaced every 100 miles (160 km) on a 36-inch diameter pipeline, so eight intermediate stations are needed and the total pumping work is 85.6 MW. 0.4% of the gas is consumed as fuel for the compressor stations.

Fugitive emissions were calculated using facility-level factors for transmissions pipelines from the 2009 API Compendium[10]. 0.066% of the gas is lost to fugitive emissions over 900 miles.

### S2.4 Power station.

It was assumed that natural gas is burned in the average U.S. power station. Power station efficiencies were taken from U.S. Energy Information Administration annual reports, as shown in **Table S3**.

**Table S3 Average power station efficiency (EIA data)**

| Year | Fuel | NET GENERATION (MWh) | FUEL CONSUMPTION (mmBTU HHV) | Efficiency (BTU/kWh) | (%) | Change 2003-09 |
|---|---|---|---|---|---|---|
| 2003 | NG | 649,907,504 | 5,735,770,025 | 8826 | 38.7% | |
| | Coal | 1,973,736,744 | 20,366,878,724 | 10319 | 33.1% | |
| 2009 | NG | 920,796,875 | 7,301,026,298 | 7929 | 43.0% | 42% |
| | Coal | 1,755,904,253 | 18,240,610,534 | 10388 | 32.8% | -11% |

**Notes:**

Coal = Anthracite, bituminous, sub-bituminous, lignite, waste coal, and synthetic coal.
NG = Natural gas (98.8% of total) excluding blast furnace gas, propane and other fossil fuel derived gas (1.2%)
Fuel consumption = share of fuel allocated to electricity (i.e. after allowing for heat exports).
2003: EIA-906 January - December Final, Excel Format (f906920y2003.xls)[11]
2009: EIA-923 January – December Final, Nonutility Energy Balance and Annual Environmental Information Data, Excel Format (EIA923 SCHEDULES 2_3_4_5 M Final 2009.xls)[12].

### S2.5 Well-to-wire totals - common elements

The total well-to-wire emissions (excluding well head operations) amount to 485.2 gCO2e/kWh; for the conventional gas base case, 487.5-490.2 gCO2e/kWh, of which 7.5% or 36 gCO2e/kWh was attributed to gas production.

These values fall within the range for gas powergen published by Jaramillo[13]: 814 to 1686 lbCO2e/MWh (369-765 gCO2e/kWh) for an efficiency range of 28-58%. If the value of 43% HHV efficiency assumed in our model is substituted, then Jaramillo's result can be scaled to give a value of 499 gCO2e/kWh for the whole life cycle, of which 6.0% or 30 gCO2e/kWh was attributed to gas production.

A second check is provided by a recent life cycle analysis of powergen from NETL[14] predicted life cycle emissions of 467 gCO2e/kWh for a power plant of 50.2% HHV efficiency with 7% transmission losses. Adjusting this figure to the value of 43% HHV efficiency assumed in our model and omitting transmission losses gives a WtW intensity of 507 gCO2e/kWh, of which 4.9% or 25 gCO2e/ kWh was attributed to gas production.

Once power station efficiency is factored out, there is broad agreement between the life cycle assessments and the modeling study.

## S3 RESULTS – CONVENTIONAL GAS

### S3.1 Production profile

Recovery from onshore conventional gas wells is in decline, indicating that the most productive fields have already been exploited. In Texas gas wells, EUR per well fell from 6.2Bcf in 1971 to 1.9 Bcf by 1990 and 1.03 Bcf by 2005[15]. Combining EIA gas withdrawal data[16] with well counts reported by EPA[2] shows a similar decline for the U.S. as a whole, from 59 mmscf/well/year in 1990 to 41 mmscf/well/year in 2005. (Given the recent take-off in horizontal drilling, it is hard to separate out conventional wells for years after 2005.) Estimates of ultimate recovery are sensitive to the assumptions made about the production profile. One method is to assume that the EPA inventory report gives a snapshot of conventional wells at every stage of a 25-year productive life. Pre-2005 production then gives a typical EUR value of 1.0 Bcf per well.

### S3.2 Well drilling.

Whereas the growth in shale gas production is linked to the growth in horizontal drilling techniques after 2005, horizontal drilling can also be used to access conventional gas. It was assumed that drilling costs per well were identical for conventional and shale gas but that the greater permeability of conventional gas formations means that fracturing is not required.

Well drilling was assumed to take 15 days at 12 hours operation per day. Emissions from fuel combustion were calculated on the basis of 4500 HP engines operating at a fuel consumption of 250 g/kWh.

### S3.3 Production emissions intensity

The waterfall plot below shows the breakdown of production emissions for vented and flared methane emissions, and a generic value based on 51% flaring.

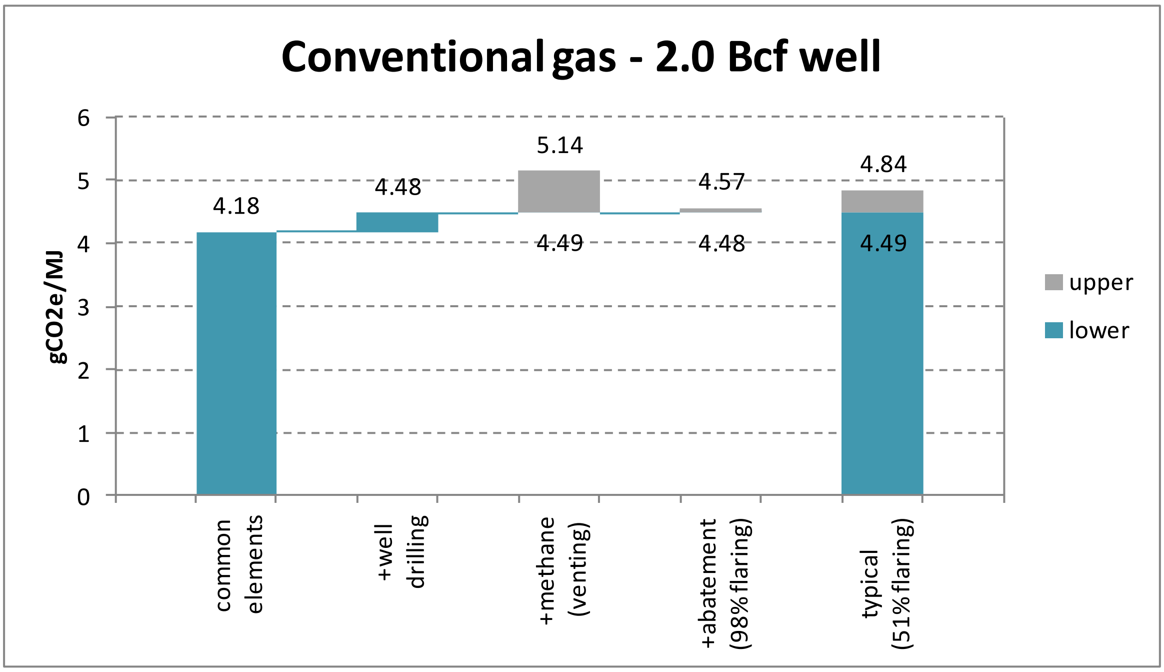


**Figure S2 Conventional base case - breakdown of production emissions sources (lower = EPA factor for methane emissions, upper = API factor)**

### S3.4 WtW emissions intensity.

The waterfall plot below shows the breakdown of production emissions for vented and flared methane emissions, and a generic value based on 51% flaring.

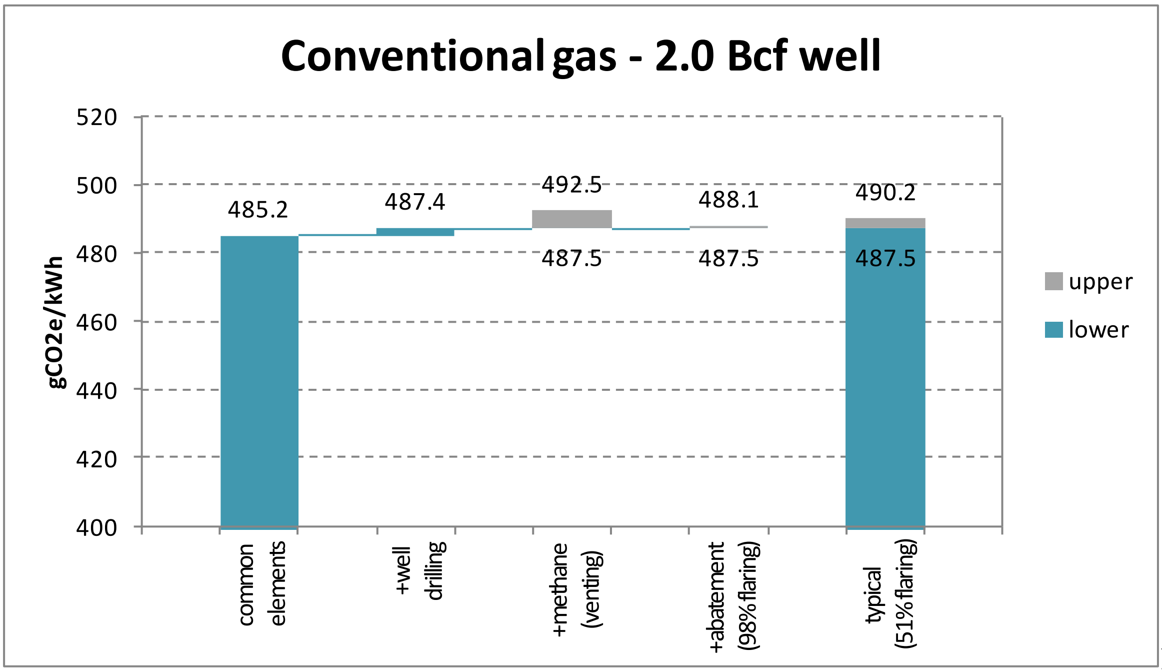


**Figure S3 Conventional base case - breakdown of WtW emissions sources (lower = EPA factor for methane emissions, upper = API factor)**

The contribution of each lifecycle stage to the WtW emissions intensity is shown in the pie chart below.

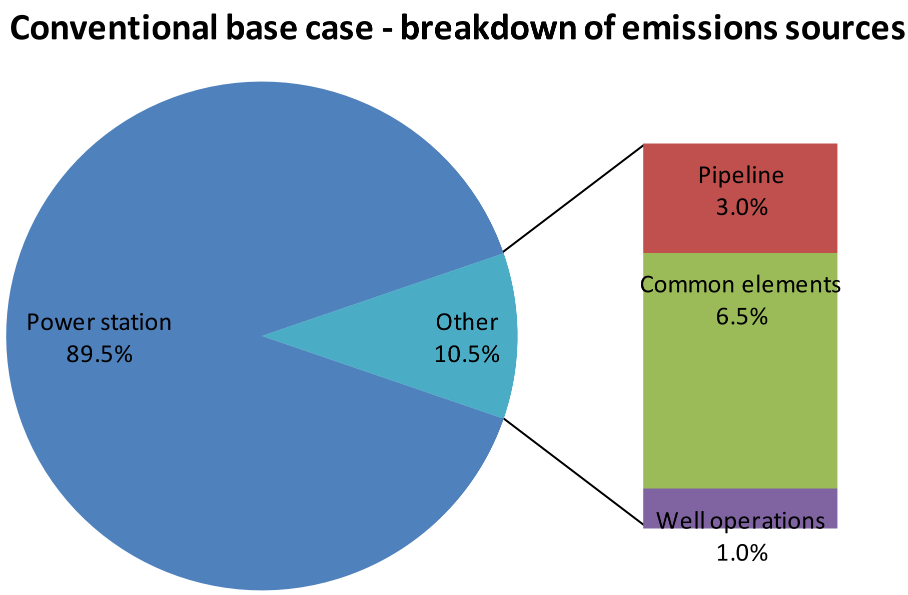


**Figure S4 Conventional base case - breakdown of emissions sources**

The WtW emissions intensity of the common elements, pipeline and power station is 485.2 gCO2e/kWh. The WtW emissions intensity of the conventional base case is 487.5-490.2 gCO2e/kWh. Well drilling makes up a relatively small part of the total WtW emissions in this conventional gas model. Gas production makes up only 7.5% of the well-to-wire total.

## S4 RESULTS - SHALE GAS

### S4.1 Production profile

A survey of data published by gas production companies shows that unconventional wells commonly show a steep decline in production, so that the estimated ultimate recovery (EUR) is typically about 3 years but can be as little as one year, see **Table S4**.

**Table S4 A survey of unconventional gas fields in the U.S.**

| **Field** | **Initial Production (IP)**<br>mmscf/d | **Estimated Ultimate Recovery (EUR)**<br>Bcf | **Field life (EUR/IP)**<br>years | **Reference** |
|---|---|---|---|---|
| Haynesville (Louisiana, shale) | 22.6 | 7.4 | 0.9 | 17 |
| Barnett (Texas, shale) | 1.3 | 1.2 | 2.6 | 18 |
| Piceance (Colorado, tight sand) | 2.0 | 1.9 | 2.6 | 19 |
| Uinta (Utah, tight sand) | 1.5 | 1.4 | 2.6 | 20 |
| CONSOL Nineveh 17D (Marcellus) | 2 | 3.5 | 4.8 | 21 |
| CONSOL Nineveh 17 (Marcellus) | 1.4 | 4.6 | 9.0 | |
| Wright 7 Company SW PA | 2.4 | 3.4 | 3.9 | 22 |
| Wright 7 Company SW PA | 6.5 | 5 | 2.1 | |
| Wright 7 Company NW PA | 4.1 | 3.75 | 2.5 | |
| Wright 7 Company NW PA | 12.2 | 7 | 1.6 | |
| Wright 7 Company normalised | 3.5 | 4 | 3.1 | |
| Marcellus (DeWitt) | 4.3 | 2.11 | 1.3 | 23 |
| Haynesville | 10 | 6.5 | 1.8 | |
| Marcellus | 4.3 | 3.75 | 2.4 | |
| Barnett | 2.5 | 2.65 | 2.9 | |
| Fayetteville | 1.9 | 2.2 | 3.2 | |
| **AVERAGE** | | **3.8** | **3.0** | |

Data from the U.S. Geological Survey[24] show that, whilst some wells achieve high EUR values, other wells have recoveries less than 0.5 Bcf (**Figure S5**). For horizontal wells, the range is 0.9 to 2.6 Bcf per well. For vertical wells, mean recovery (total gas divided by total wells) can be as high as 3 Bcf (Bossier) or less than 0.5 Bcf per well (Woodford and Fayetteville). However, such wells contribute little to the total gas volume produced, which skews the mean recovery from a field to be always higher than the median recovery (extremely so in the case of Haynesville).

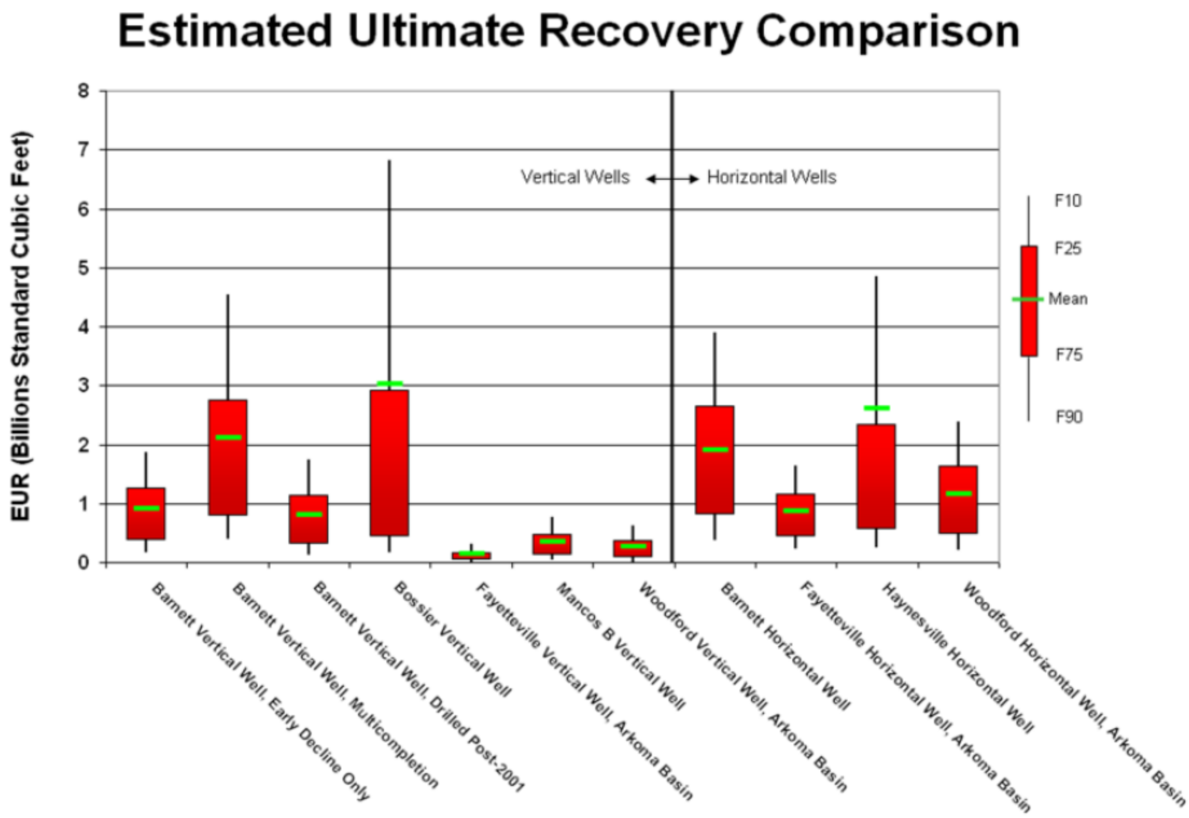


**Figure S5 U.S. Geological Survey – predicted ultimate recovery for shale gas wells**

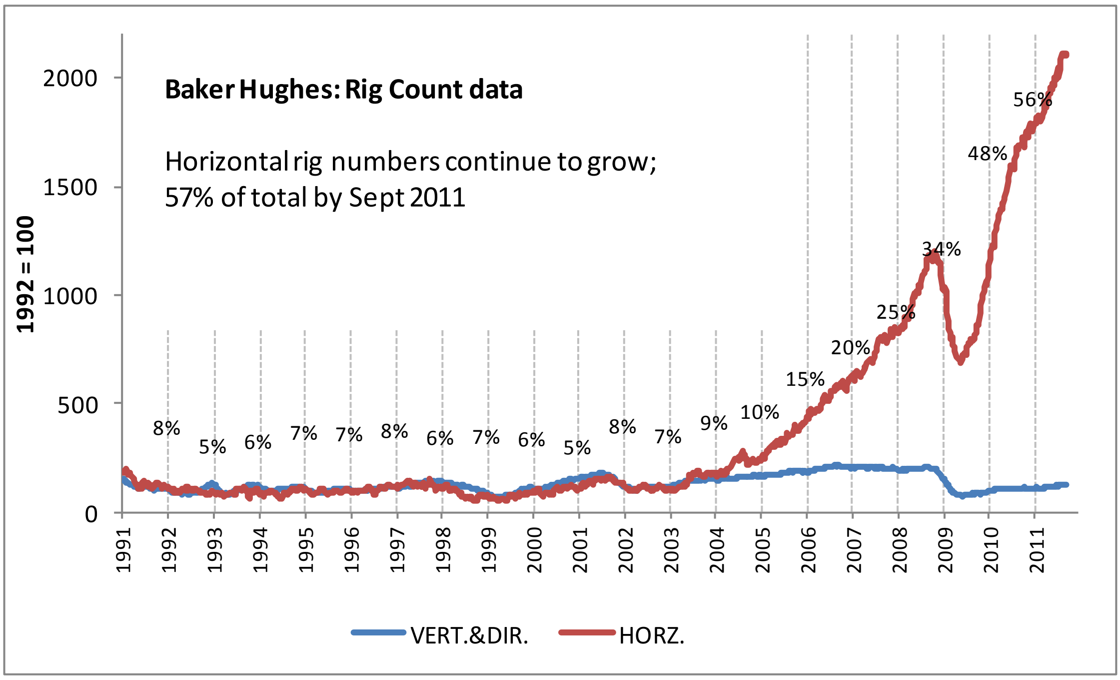


**Figure S6 Horizontal drilling rig numbers have increased sharply since 2005 and since 2010 make up the majority of all active rigs.**

Rig count data from Baker Hughes[25] show that there are now more horizontal drilling rigs than any other type and the number is growing. It is to be expected that future growth in gas production will be from horizontal wells. For this study, the USGS result of 2 Bcf per well for Barnett shale horizontal wells was taken as typical of modern shale gas production.

As the USGS data show, some wells may have recoveries much higher or lower than this, but the industry average will be less variable than individual wells. Improved production techniques, or better targeting of “sweet spots” might lead to an increase in industry average recovery, so a value of 3 Bcf per well was included as a sensitivity case. Alternatively, recovery might be lower than this, either as a result of underestimating reserves, or through natural decline when the most productive reserves are exhausted. A lower value of 1 Bcf per well was also included in the sensitivity analysis (i.e. same as conventional wells).

The “worst case” analysis does look at individual wells, recognising that there may be some wells for which the emissions intensity of production may deviate strongly from the industry average. An upper bound of 4.5 Bcf per well was taken as indicative of some of the most productive wells listed in **Table S4**. The lower bound was taken to be 0.5 Bcf per well, below which recovery is unlikely to be economic.

### S4.2 Well drilling and fracturing.

It was assumed that drilling costs per well were identical to the conventional gas case, but that the lower permeability of conventional gas formations required fracturing.

Well fracturing was assumed to require 2 hours per operation and 15 operations per well Fracturing fluid was assumed to flow at 50 bbl/min at 10,000 psi (8 $m^3$/min and 689 bar) corresponding to a "hydraulic horsepower" of 12,250 HP. Emissions from fuel combustion were calculated on the basis of 12,250 HP engines operating at a fuel consumption of 250 g/kWh.

### S4.3 Production emissions intensity

Unlike conventional gas, well drilling and fracturing makes up a significant part of the total production emissions. Adding well drilling/fracturing, flowback water treatment and fugitive emissions from well completions changes the emissions intensity as shown in **Figure S7** below:

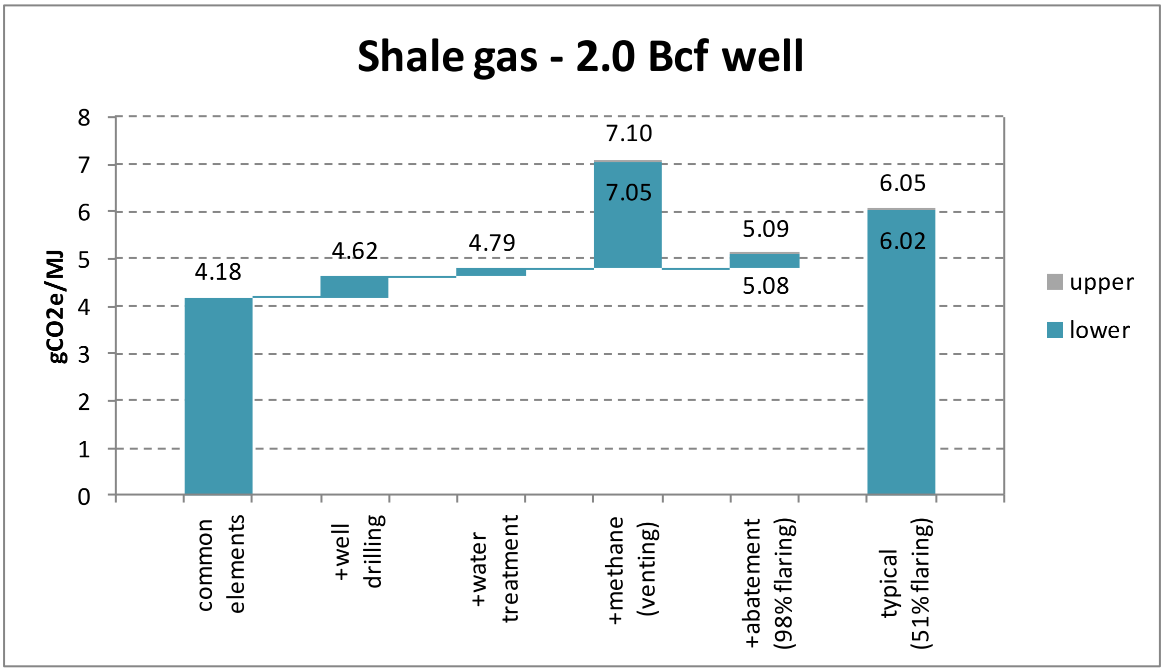


**Figure S7: Contribution of well drilling, flowback water treatment and well completion methane releases to production emissions intensity. (lower = EPA factor for methane emissions, upper = API factor)**

### S4.4 WtW Emissions intensity.

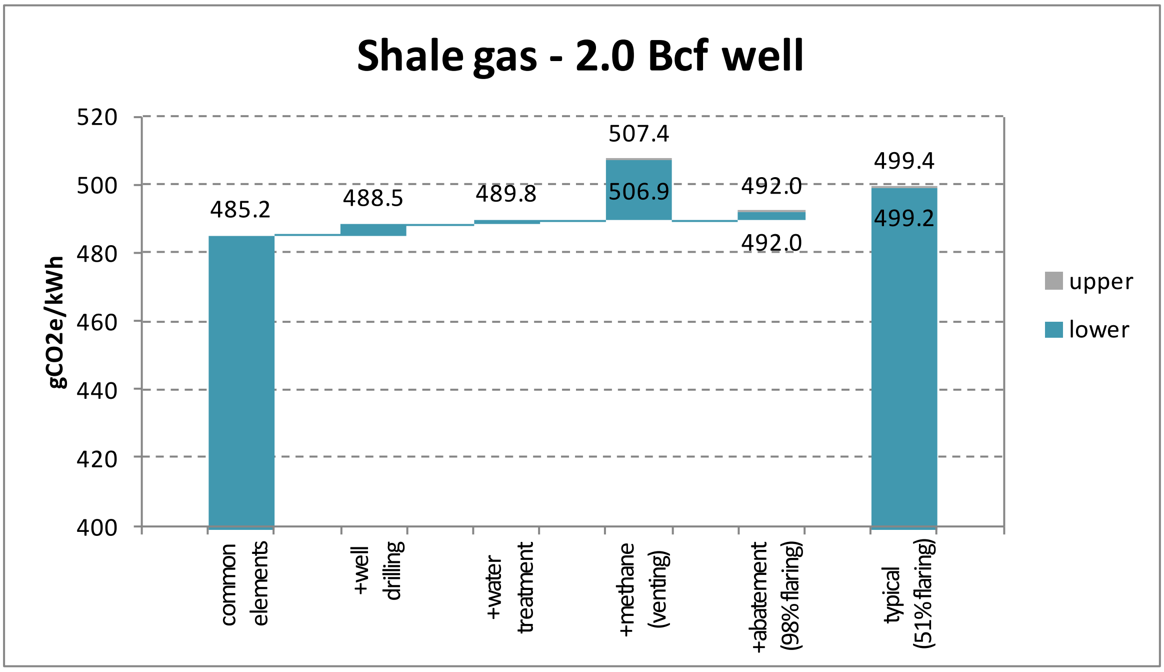


**Figure S8: Contribution of well drilling, flowback water treatment and well completion methane releases to WtW emissions intensity. (lower = EPA factor for methane emissions, upper = API factor)**

The contribution of each lifecycle stage to the WtW emissions intensity is shown in the pie chart below.

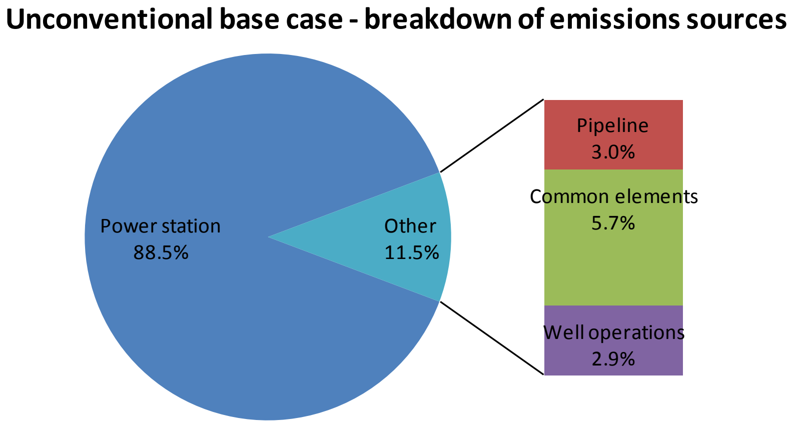


**Figure S9: Shale gas base case - breakdown of emissions sources**

## S5 RESULTS - SENSITIVITY ANALYSIS

### S5.1 Production emissions intensity

To describe more or less difficult unconventional gas production, the following parameters were varied above and below the base case:

- Ultimate recovery
- Produced water treatment
- Well completion emissions
- Completion/workover emissions abatement
- Wellhead gas pressure
- Flowback water volume
- Fractures per well

The results of these sensitivity cases on production emissions are shown as a tornado plot in **Figure S10** below.

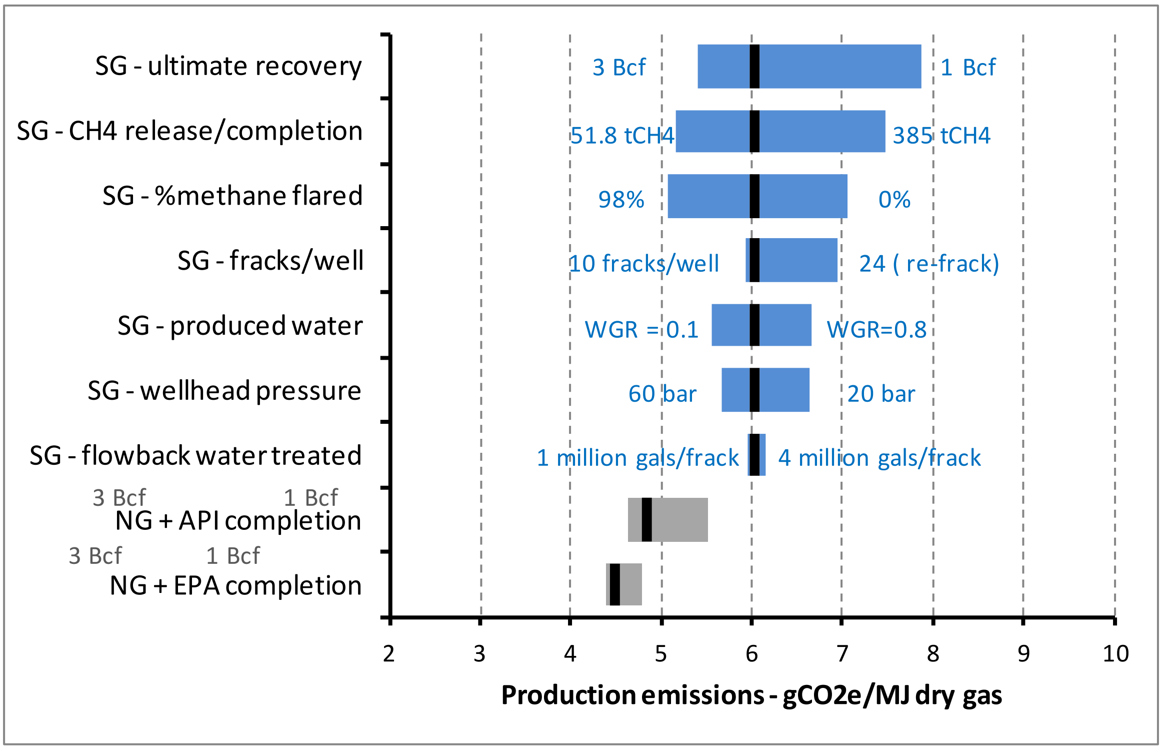


**Figure S10 Sensitivity of production emissions intensity to changes in unconventional gas production parameters (gCO2e/MJ)**

## S5.2 WtW emissions intensity

The results of these sensitivity cases on WtW emissions are shown as a tornado plot

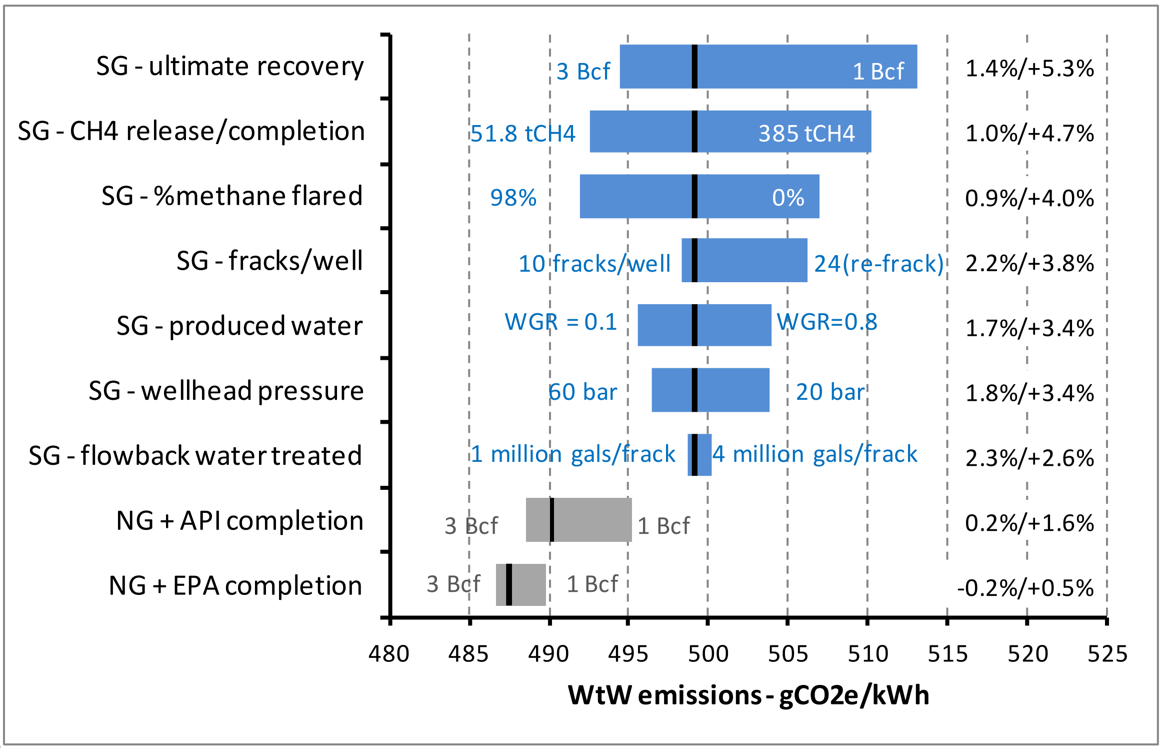


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Figure S11**Figure S11** below.

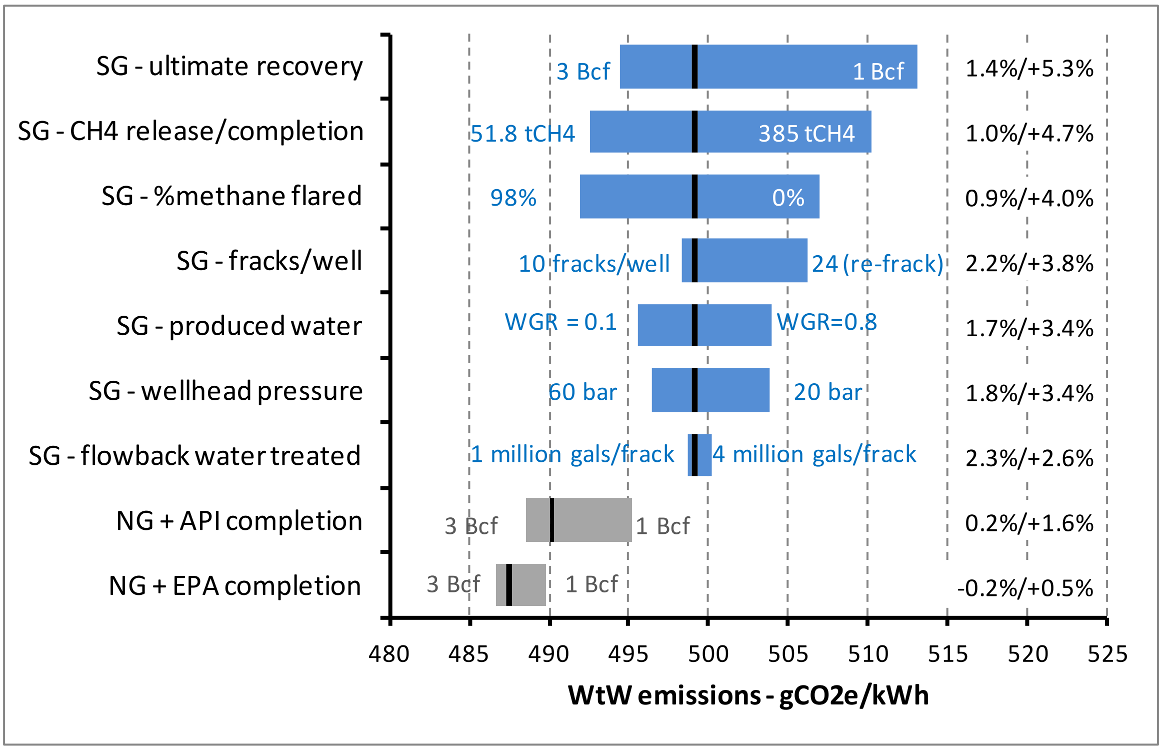


**Figure S11 Sensitivity of WtW emissions intensity to changes in unconventional gas production parameters**

### S5.3 Summary table

**Table S5: Summary of conventional and shale gas model inputs and intensities, with sensitivity to ultimate recovery.**

| | Conventional gas | | | | Shale gas | | | |
|---|---|---|---|---|---|---|---|---|
| | low | **base(EPA)** | base(API) | high | low | **base(EPA)** | high | units |
| Production | 750 | **750** | 750 | 750 | 750 | **750** | 750 | mmscf/day |
| Estimated ultimate recovery (EUR) | 3.0 | **2.0** | 2.0 | 1.0 | 3.0 | **2.0** | 1.0 | Bcf |
| Wells drilled per year | 91 | **137** | 137 | 274 | 91 | **137** | 274 | |
| Drilling/fracturing | | | | | | | | |
| diesel usage | 178 | **178** | 178 | 178 | 260 | **260** | 260 | $m^3$/well |
| methane released | 0.71 (EPA) | **0.71 (EPA)** | 51.8 (API) | 51.8 (API) | 177 | **177** | 177 | $tCH_4$/well |
| Water haulage/treatment | | | | | | | | |
| diesel usage | 0 | **0** | 0 | 0 | 75.6 | **75.6** | 75.6 | $m^3$/well |
| electricity | 0 | **0** | 0 | 0 | 730 | **730** | 730 | kWh/well |
| Life cycle emissions (100-year GWP) | | | | | | | | |
| wellhead operations | 3.4 | **2.3** | 7.3 | 4.6 | 9.3 | **14.0** | 28.0 | |
| gas treatment | 31.8 | **31.8** | 31.8 | 31.8 | 31.8 | **31.8** | 31.8 | |
| pipeline | 14.7 | **14.7** | 14.7 | 14.7 | 14.7 | **14.7** | 14.7 | |
| power station | 438.7 | **438.7** | 438.7 | 438.7 | 438.7 | **438.7** | 438.7 | |
| total | 488.5 | **487.5** | 492.5 | 489.8 | 494.5 | **499.2** | 513.1 | gCO2e/kWh |
| | | | | | | 1.4%-2.4% | | |
| Life cycle emissions (20-year GWP) | | | | | | | | |
| wellhead operations | 6.4 | **2.4** | 9.6 | 19.3 | 19.9 | **29.8** | 111.8 | |
| gas treatment | 52.2 | **52.2** | 52.2 | 52.2 | 52.2 | **52.2** | 0.0 | |
| pipeline | 18.9 | **18.9** | 18.9 | 18.9 | 18.9 | **18.9** | 18.9 | |
| power station | 439.0 | **439.0** | 439.0 | 439.0 | 439.0 | **439.0** | 439.0 | |
| total | 516.6 | **512.5** | 519.8 | 529.4 | 530.0 | **539.9** | 569.7 | gCO2e/kWh |
| | | | | | | 3.9%-5.3% | | |

## S6 RESULTS - WORST CASE ANALYSIS

In the sensitivity cases explored above, the various parameters were varied one at a time. The following comparison applies all the changes at the same time to derive best and worst cases. The results are shown in **Figure S12Figure S12** below.

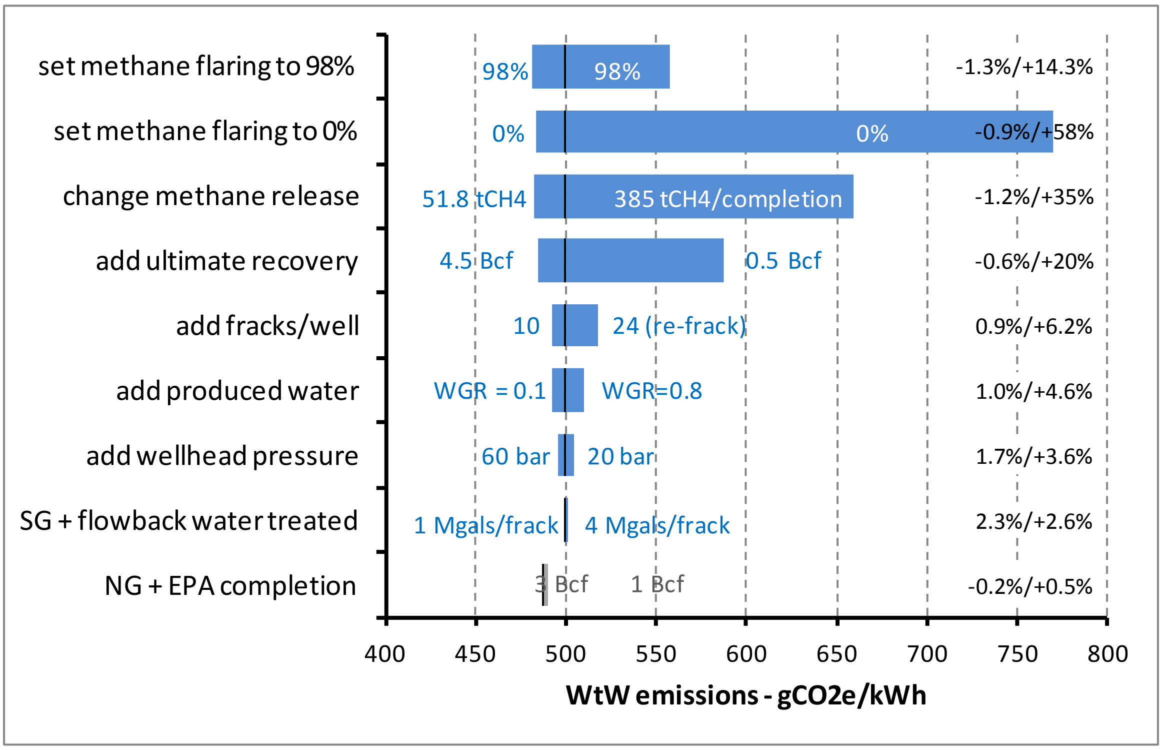


**Figure S12 Best and worst case WtW emissions relative to conventional gas**

In unfavorable circumstances, the WtW emissions of shale gas could be considerably higher than conventional gas powergen but if efficient flaring or recovery of methane releases is in place, WtW emissions need be not be much higher than conventional gas powergen.

## S7 DISCUSSION

### S7.1 Reassessment of Howarth results

Howarth et al.'s letter to Climatic Change[1] claims that GHG emissions from shale gas combustion could be more than twice those of coal. The consensus view is that gas powergen has half the GHG emissions of coal powergen, based on publications by Jaramillo[13], CMU[26] and NETL[14]. A simplified analysis was carried out, consisting of combustion emissions and methane releases only (not a full LCA) to identify how these differences arose.

Five major contributing factors have been identified:

**Methane leaks:** EPA 2011 Inventory Report[2] estimates total methane losses to be 10535 Gg (kilotonnes) in 2009, of which production accounts for 59%, processing 8%, transmission 20% and distribution 13%. EIA data[3] for total gas production = 21.5 quadrillion BTUor 20.93 Tcf. 10535 ktCH4 is 0.55 Tcf, so EPA's estimated losses amount to 2.6% of the total produced. Howarth estimates 1.7-6.0% for conventional gas (0.65-2.3 times the EPA average), 3.6-7.9% for shale gas (1.4-3.04 times the EPA average).

**Flaring of methane releases in production**: EPA estimate that 51% of unconventional gas wells are in states that mandate flaring[27]. Flaring is typically 98% efficient. Howarth assumes that, in the worst case, all methane emissions are vented, making GHG emissions 1.92 times higher than the EPA average (this factor only applies to production releases - 59% of total inventory).

**Powergen efficiency:** Howarth mentions, but does not evaluate, differences in powergen efficiency. The U.S. average for existing coal powergen is 32.8% efficiency or 10388 BTU/kWh, whereas gas powergen is 43.0% efficient or 7929 BTU/kWh (see **Table S3**). If a functional unit of kWh of electricity had been used instead of combustion emissions, shale gas “well-to-wire” emissions would have been lower by a factor of 1.31.

**IPCC vs Shindell GWP:** Howarth uses a 20-year GWP for methane of 105 derived from work by Shindell[28], whereas the IPCC factor is 72 gCO2e/gCH4. As a result, Howarth calculates GHG emissions of methane 1.46 times higher than if IPCC factors had been used.

**20 vs 100-year GWP:** IPCC’s 20-year factor for methane is 72 gCO2e/gCH4, whereas the more commonly used 100-year factor is 25 gCO2e/gCH4. As a result, Howarth calculates GHG emissions of methane 2.88 times higher than if IPCC factors had been used.

Two of Howarth's cases were considered, taken from Figure 1 of his letter:

| | |
|---|---|
| Unconventional gas (high estimate): | 15 gC/MJ (combustion CO2)<br>+45.2 gC/MJ (7.9% methane release)<br>= 60.2 gC/MJ in total. |
| Surface mined coal (low estimate): | 25 gC/MJ (combustion CO2)<br>+1.44 gC/MJ (methane release)<br>= 26.4 gC/MJ in total. |

If average methane emissions are assumed to be 2.6% (in line with the EPA inventory for 2009), and the five factors above are applied, then gas powergen would have 53% of the WtW emissions of coal - in line with the consensus view (**Figure S13**).

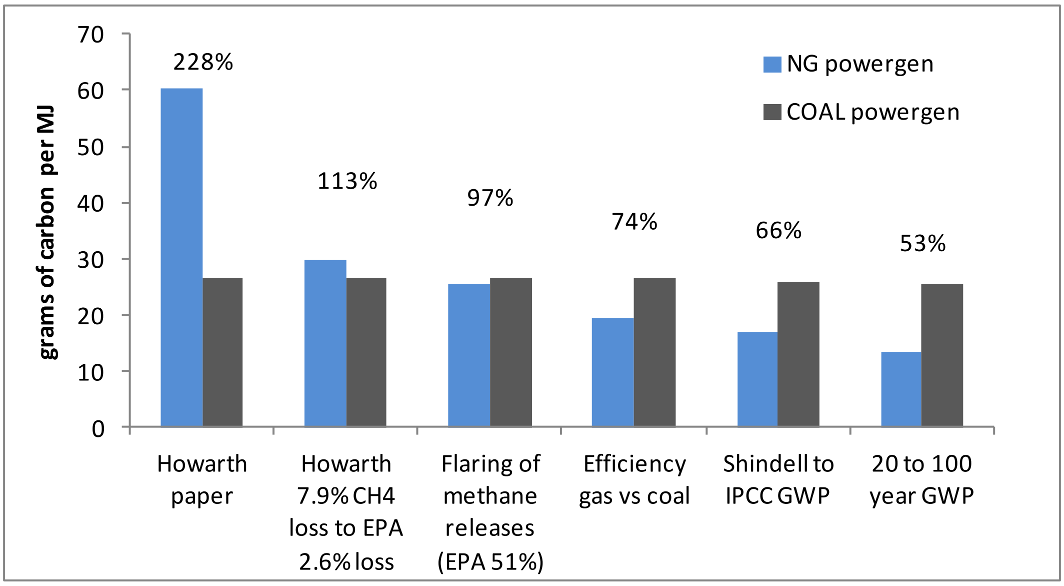


**Figure S13 Average gas WtW emissions relative to coal**

Even in the worst case, where methane releases were as high as 7.9%, once the five factors are applied, shale gas powergen would have emissions only 69% those of coal powergen (**Figure S14**).

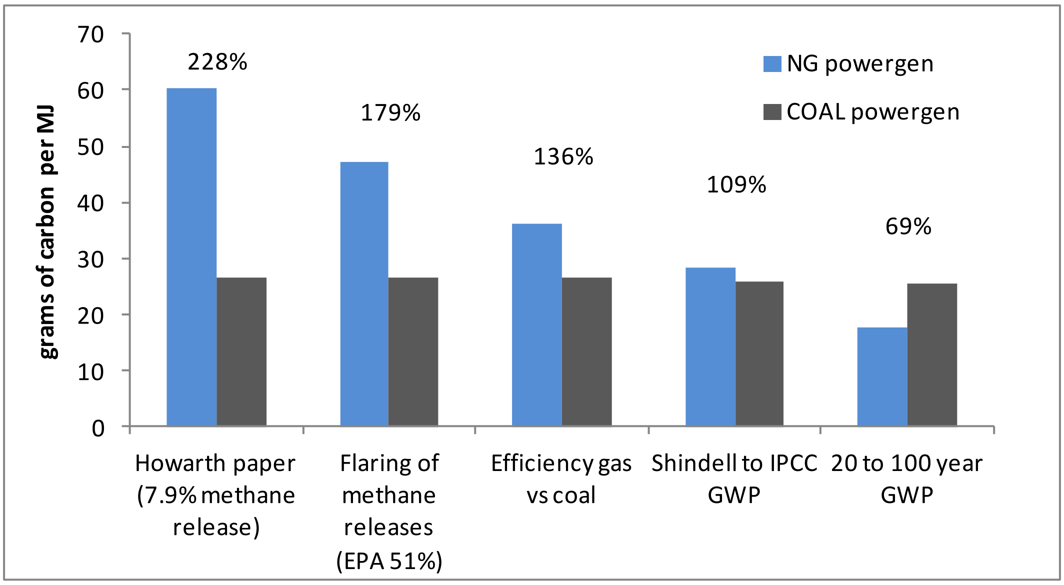


**Figure S14 Worst case shale gas WtW emissions relative to coal**

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