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PROJECTIONS OF FUGITIVE GREENHOUSE GAS EMISSIONS TO 2020

technology

Report prepared for the
Australian Greenhouse Office

by

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List of Abbreviations

CH_4	methane
CO_2	carbon dioxide
CO_2-e	carbon dioxide equivalent (i.e sum of CO_2, CH_4 and N_2O emissions each multiplied by appropriate Global Warming Potential factor) .
LCM	Low Concentration Methane
MCM	Medium Concentration Methane
N_2O	nitrous oxide
WCMG	Waste Coal Mine Gas
UAG	Unaccounted for Gas

1. SUMMARY

This study analyses the Fugitive Emissions sector of the National Greenhouse Gas Inventory (NGGI). Fugitive emissions accounted for about 6.8% of total net emissions in 1996/97 (land clearing excluded). Emissions from Fugitive Emissions increased by only 0.5% between 1990 and 1997, compared with a 10.2% increase in total net emissions.

Table 1 summarises the subsectoral contributions to fugitive emissions in 1997. Coal mining accounted for nearly 64% and venting and flaring from hydrocarbons production for nearly 29%. Nearly 78% of the greenhouse impact of the sector was fugitive methane. The contribution of nitrous oxide is very small and also very uncertain (it is a minor product of side reactions in flares). For these reasons, it has been ignored in preparing the projections.

Table 1 Fugitive emissions by subsector, 1997

Subsectors	**Gg CO_2**	**Gg CH_4**	**Gg N_2O**	**Gg CO_2-e**	**Percent**
Coal (Net)	459	808	0.00	17422	57%
Petroleum	6340	327	0.07	13226	43%
of which:					
Venting & Flaring	5294	163	0.06	8729	28%
Gas distribution	0	155	0.00	3260	11%
Other sources	1046	9	0.01	1237	4%
Total fugitive emissions	**6799**	**1135**	**0.07**	**30648**	**100%**

Note: Values are slightly higher than published in the 1997 NGGI, due to methodology revisions (see below)

This report is arranged in two large Chapters, dealing with each of the two subsectors, coal and petroleum. This study analyses the factors affecting the estimates of future emissions in each of the subsectors. The factors can generally be grouped into:

1. rates of growth in the production of coal, petroleum and natural gas;
2. the characteristics, e.g. gassiness of coal fields, CO_2 content of gas fields, of the coal, gas and oil fields currently under production, and those which may be developed over the projection period;
3. management issues such as the extent of mitigation and utilisation of waste coal mine gases and the maintenance of natural gas distribution systems; and
4. methodological issues bearing on the way that data is collected, and on the possible addition of further elements to the fugitive inventory.

In the case of coal emissions, a distinction is made between gross fugitive emissions, which are calculated prior to any capture, and net fugitive emissions. In the case of the major source of petroleum emissions, venting and flaring, mitigation by way of capture and sequestration of the CO_2 emitted is a technically feasible, but relatively costly, procedure, and not one which is widely practiced anywhere in the world at present. We have assumed no explicit policy intervention to require CO_2 sequestration.

For each subsector, and each component of each subsector, at least three emissions scenarios are developed:

- A “Business as Usual” (BAU) case, generally based on projections of production published by the Australian Bureau of Agricultural and Resource Economics (ABARE), present physical characteristics and, in the case of coal mining, the continuation of present rates of recovery of methane;
- A “High” scenario, generally incorporating higher production growth, a trend to exploitation of more emissions intensive resources, and no additional recovery efforts beyond those in the BAU case;
- A “Low” case, generally incorporating lower production growth, a trend to less emissions intensive resources, more active recovery of coal mine methane, and, and no development of two large and particularly CO_2 intensive gas fields.

The findings are illustrated in Figures 1, 2 and 3. Figure 1 shows the subsectoral contributions to the BAU projection. Emissions are projected to increase by over 60% of the 1991 value by 2020, mainly due to coal mining and venting from gas production. Leakage from natural gas is projected to remain nearly constant, while emissions associated with flaring at oil and gas production facilities and oil refineries are expected to decrease. It can also be seen that coal accounts for a little over half the total emissions throughout the period.

Figure 2 shows the shares of the total greenhouse impact contributed by the two gases. Methane contributes between 70% and 80% of total CO_2-e emissions throughout the period, with the share falling slightly in later years.

Figure 3 shows total emissions under each of the three scenario cases. In the “High” case the increase is projected to be about 85% of the 1990 value. In the “Low” case there is virtually no change, with decreases from coal, and some sources of petroleum related emissions, offsetting increases from venting. The big gap between the "Low" case and the other two cases is mainly attributable to the lack of the two CO_2 intensive gas fields mentioned above. The changes are summarised in Table 2.

It should be noted that the values for the years 1990 to 1997 inclusive are slightly higher than those reported in the published NGGIs for the various years. The difference is attributable to changes in methodology, which are considered to provide an improved estimate of actual emissions.

- Estimated emissions of CO2 released from coal seams (see Section 2.2.4) and from spontaneous combustion of waste coal (see Section 2.2.5) are included. This change has the effect of increasing fugitive emissions from coal mining, relative to the NGGI, by between 4.5% and 5.0%.

- Emissions of CO2, contained in pipeline quality natural gas and released "at the burner tip" when combustion occurs, are also included (see Section 3.5.3. This change has the effect of increasing fugitive emissions from petroleum, relative to the NGGI methodology, by about 5% in 1990, with the increase rising to about 10% by 2007.

It is expected that the second of these methodological changes will be included in the NGGI from 1998 onward, with retrospective adjustments, as in this Report, made for earlier years. Consideration of the methodological changes relating to coal mining emissions may be possible, following the expected release of detailed new report on coal mine fugitive emissions later in 2000.

Table 2 Summary of projection scenarios

				Change, 1990-2020	
Scenarios	**1990 Mt CO_2-e**	**2010 Mt CO_2-e**	**2020 Mt CO_2-e**	**Mt CO_2-e**	**Percent**
Highest	30.8	46.9	55.5	24.7	80%
BAU	30.8	38.7	44.1	13.3	43%
Lowest (a)	29.6	27.8	29.4	-0.2	-1%
Highest cf BAU	0.0	8.2	11.4		
Lowest cf BAU	-1.2	-10.9	-14.7		
Maximum range	1.2	19.1	26.1		

(a) This involves a change in methodology affecting gas distribution, which would also have to be applied retrospectively (see Section 3.5.2)

Measures to increase the capture of coal mine methane would have impacts on other parts of the NGGI, beyond the fugitive sector. If the captured methane were flared, the combustion emissions would need to be added to the NGGI – probably in a new subsector. If the captured methane were used to generate electricity, it would most likely displace some use of fossil fuel, and so bring about a reduction in emissions in the other parts of the NGGI.

Figure 1 Projected fugitive emissions under Business as Usual, by source sub-sector and gas, 1990 to 2020

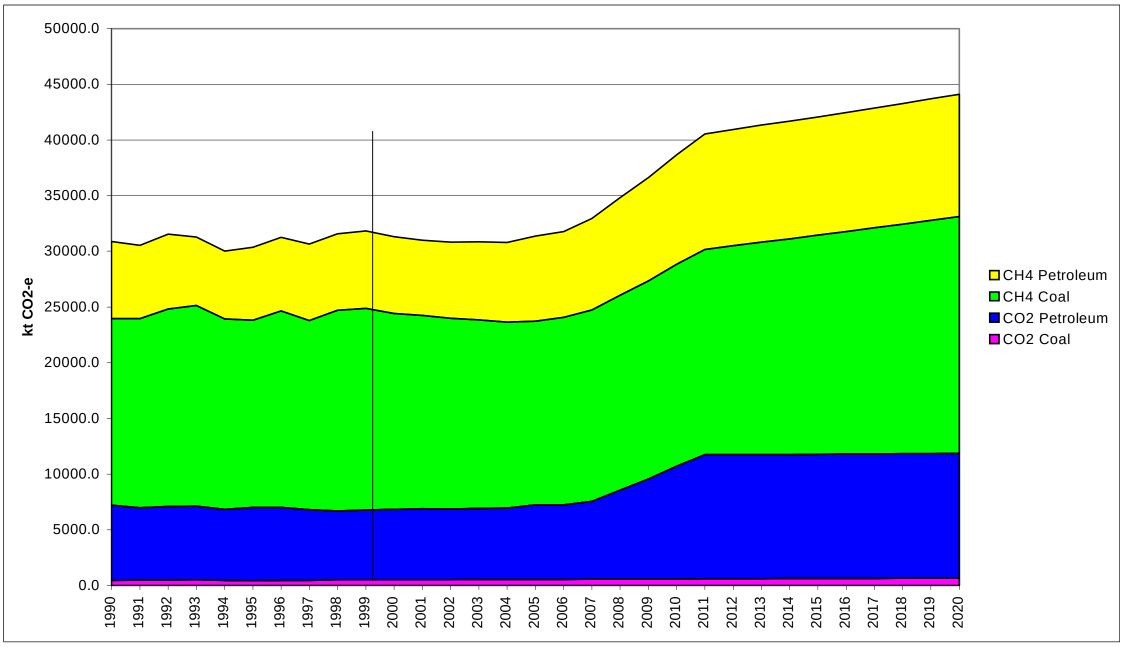


Figure 2: Contributions to total fugitive emissions of each greenhouse gas, 1990 to 2020

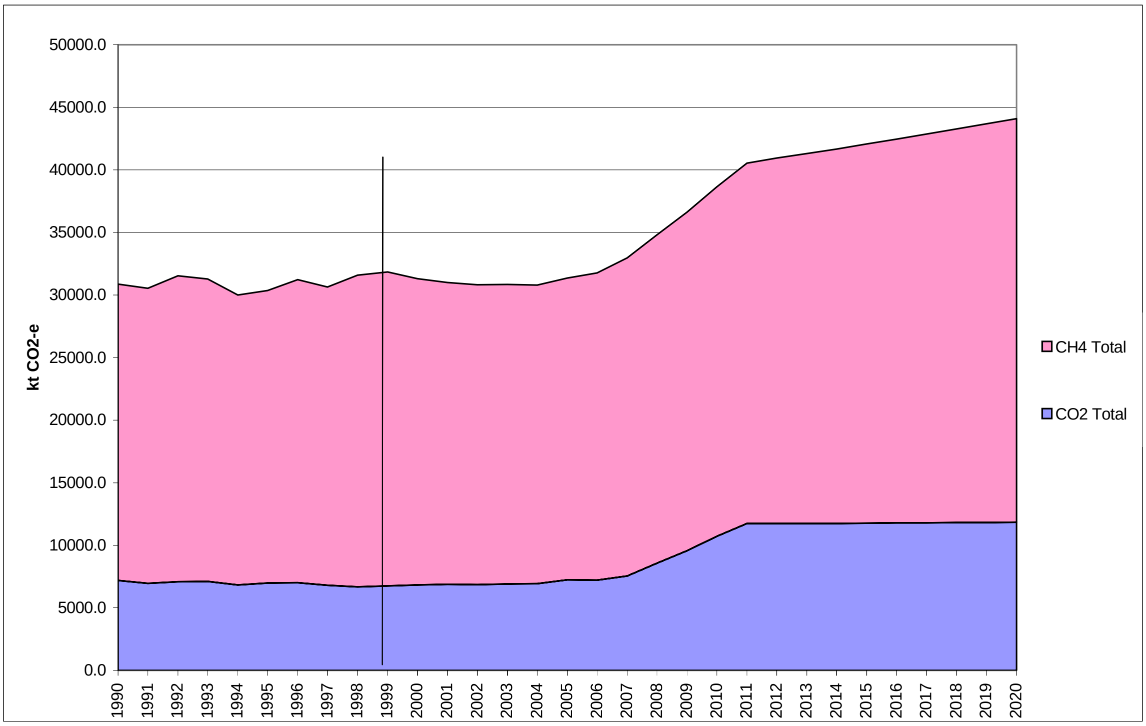
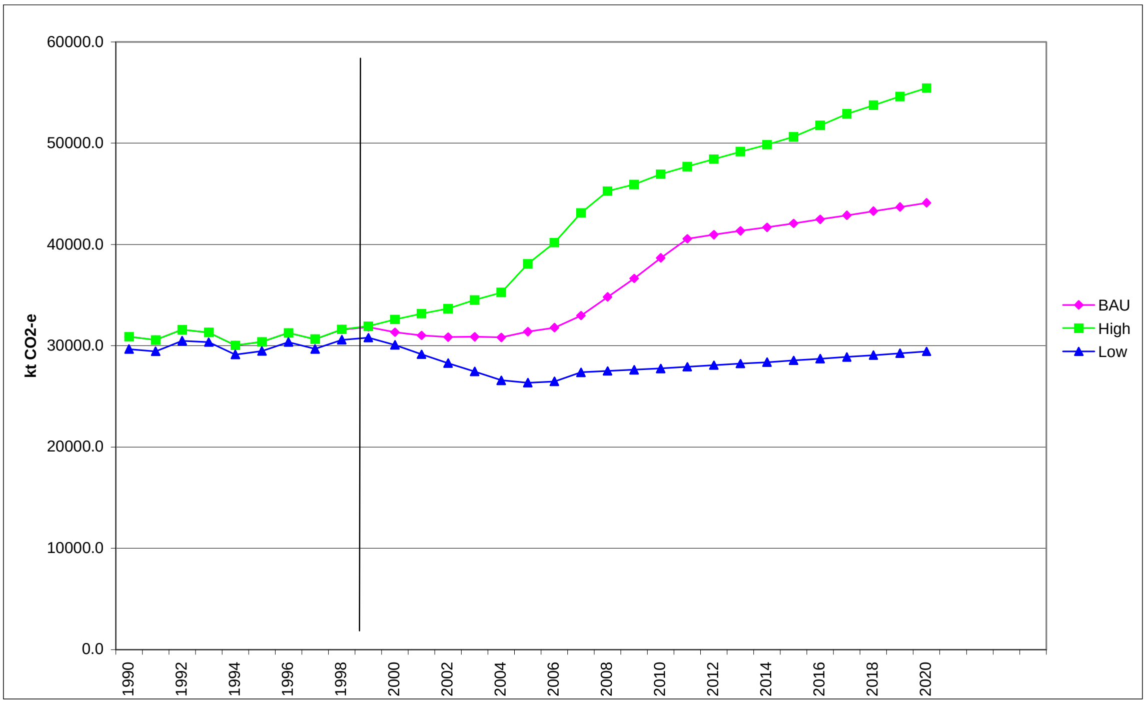


Figure 3: Projected total fugitive emissions under BAU, High and Low scenarios, 1990 to 2020



2. EMISSIONS FROM COAL MINING

2.1 Inventory-wide contribution

Coal mining activity has a number of impacts on the NGGI. The major impact is the release of fugitive methane and CO_2 emissions during and after the mining of black coal. This accounted for nearly 57% of the Fugitive Emissions sector of the NGGI in 1997, and the quantity would have been higher still had there not been some capture of waste coal mine gas for electricity generation.

Other impacts of coal mining activity show up in other parts of the NGGI:

- CO_2 and trace quantities of other greenhouse gas emissions are released in the combustion of fossil fuels to provide electricity, the main form of energy used in underground mining. These are accounted in the fuel combustion part of the NGGI (subsector 1A1a, Electricity and Heat Production), whether they occur at or away from the mine site;
- CO_2 and trace quantities of other greenhouse gas emissions are released in the combustion of diesel fuel, the main form of energy used in open cut mining. These are accounted in the fuel combustion part of the NGGI (subsector 1A1c, Manufacture of Solid Fuels and Other Energy Industries – Coal Mining).

A recent study (Deslandes, 1999) calculated the greenhouse gas intensity of coal production in 1998, including electricity use, diesel use and net fugitive emissions (i.e. after taking methane recovery into account). The findings are summarised in Table 3.

As there are no fugitive emissions from brown coal, all emissions from brown coal production are related to energy use. For black coal produced by the open cut method, about half the emissions related to energy use and half to fugitive emissions. For black coal mined underground, fugitive emissions accounted for over 90% of the emissions-intensity.

Table 3 Greenhouse intensity of saleable coal production, Australia 1998

Mine Type	**Greenhouse Intensity Fuel combustion (tonnes CO_2 / tonne)**	**Greenhouse Intensity, net fugitive emissions (tonnes CO_2 -e/ tonne)**	**Overall Greenhouse Intensity (tonnes CO_2 -e/tonne)**
Open cut brown coal	0.005	0	0.005
Open cut black coal	0.024	0.026	0.050
Underground black coal	0.018	0.195	0.213
Australian Average	**0.018**	**0.061**	**0.079**

Source: Derived by author from Deslandes (1999): tonnage is saleable, not raw coal

It is estimated that in 1998, about 14% of the fugitive waste methane emissions from underground coal mining were captured. Without this capture, the overall greenhouse intensity of underground black coal would have been about 0.245 tonnes CO_2-e/tonne. Clearly, the higher the rate of capture of fugitive waste methane emissions, the lower the total of net fugitive emissions from coal mining.

The captured methane can be mitigated in two ways. It can be flared, in which case the combustion CO_2 and other emissions products will enter the fugitive emissions part of the NGGI (probably 1B1c, Solid fuels – Other). Burning a quantity of methane instead of venting it reduces the CO_2-e emissions by 87%.

The alternative is to use the captured methane for electricity generation. In that case the combustion CO_2 and other emissions products will enter not the fugitive emissions but the fuel combustion part of the NGGI (subsector 1A1a, Electricity and Heat Production). However, the generation of electricity with waste methane would displace electricity that would otherwise have been generated by conventional fuels, so there will be a reduction in the emissions from coal and natural gas in the Electricity and Heat Production subsector. It is estimated that for each kt of CO_2-e added to the subsector through the combustion of waste methane for electricity generation, about 2.4 kt CO_2-e from the combustion of other fuels is avoided (Energy Strategies et al, 1999). Therefore there is a net reduction of 1.4 kt CO_2-e in the fuel combustion inventory, in addition to the reduction in the fugitive inventory due to the capture of the methane.

Table 4 illustrates the options with regard to one hypothetical mine, which vents 1,000 tonnes of methane (CH_4) per year. This could be flared, or used to generate about 5.9 GWh of energy (using gas engines), so avoiding the need to send out about 6.5 GWh from grid-connected power stations. Capturing and flaring the methane would reduce the total greenhouse impact (in-site and off-site) by about 64%. On-site generation using the captured methane would reduce the total greenhouse impact by 90%.

Table 4 Summary of emission options at a coal mine venting 1,000 tonnes methane per year

	Tonnes CH_4 captured	**Tonnes CH_4 emitted**	**GWh generated on site(a)**	**Tonnes CO_2 emitted on site**	**GWh sent out off site (b)**	**Tonnes CO_2-e emitted on site**	**Tonnes CO_2 emitted off site(c)**	**Total tonnes CO_2-e emitted**
No capture	0	1000	0	0	6.50	21000	6498	27498
Capture for flaring	1000	0	0	2750	6.50	2750	6498	9248
Capture for generation	1000	0	5.85	2750	0	2750	0	2750

(a) assuming 170 t CH_4/GWh

(b) In order to deliver the same amount of electricity that would be generated on site with use of captured methane, assuming 10% system losses

(c) assuming 1.0 kt CO_2-e/GWh sent out.

To sum up,

- if waste methane is captured and flared, there is a reduction in the fugitive emissions part of the NGGI, and no effect on the other parts;
- if the same amount of waste methane is captured and used in generation (whether at the mine site or piped elsewhere) there is a slightly larger reduction in the fugitive emissions part of the NGGI, and a further reduction in the fuel combustion part of the NGGI.[1]

Therefore the mode of use of the captured waste methane, not just the quantity captured, determines how it impacts on the NGGI.

This only applies to methane captured in the course of coal mining. The NGGI treats emissions from the combustion of coal seam methane produced separately from the mining operation, e.g. by drilling boreholes in advance of mining, in the same way as natural gas or any other fossil fuel.

2.2 Fugitive emissions

2.2.1 Sources of emissions

The dominant source of fugitive emissions from coal mining is the release of absorbed coal seam gas from the mine and from the mined coal. Coal seam gas consists of methane, carbon dioxide, or a mixture of the two. Carbon dioxide, and sometimes smaller quantities of methane, may also be released due to oxidation of stored coal residues and mining wastes.

Of these sources, only the methane in the coal seam gas is currently entered in the NGGI. The carbon dioxide in the coal seam gas and the emissions from oxidation of coal residues are not currently estimated for the NGGI, but could be – some estimates are made in the following sections.

2.2.2 Release of methane from coal seams

Most coal seams contain methane, and often other gases, particularly carbon dioxide, trapped within the interstices of the coal. The quantity of methane in the coal depends on a number of factors, including the rank of the coal and the depth of the seams concerned. In general, coal rank determines the quantity of methane generated within the seam over its geological history; the higher the rank, the greater the quantity generated. Other factors, including depth of occurrence, the pressure of the gas and the temperature of the coal, affect how much of the methane originally generated remains in the seam today. The gas is

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[1] It is understood that at least one company includes the exhaust gas from the gas engines with the fugitive emissions, and subtracts a “displacement credit” by multiplying the electricity generated by a state average electricity emissions factor. This form of reporting is acceptable for the purposes of programs such as the Greenhouse Challenge, but if mine-specific data were reported for NGGI purposes, only the actual net fugitive emissions value should be used.

liberated during the stress redistribution and fracturing of coal and rock that occurs during mining.

Ever since underground coal mining began, many centuries ago, the release of methane and its build up in mine tunnels and shafts has been a major hazard of the industry. Many accidents have been caused by underground explosions of methane. Modern underground coal mining techniques place heavy emphasis on preventing the underground build up of methane concentrations.

Ventilation is the principal method of controlling methane concentrations in mines. Large volumes of air are drawn into every part of the mine, and the exhaust is collected and vented at the surface. Ventilation systems are operated to ensure that the concentration of methane in the exhaust remains at a very low level, thereby providing assurance that it is at safe levels in all parts of the mine.

Methane in ventilation exhaust can be characterised as *Low Concentration Methane (LCM).* The methane concentration is nearly always less than 1.2% methane concentration by volume, and it may be very low (less than 0.1%) in so-called non-gassy mines, i.e. mines where the coal seams contain only small quantities of methane. These small quantities of methane are mixed with air in the mine ventilation exhaust system. Because of the low methane concentrations and the large flow rates, LCM is difficult to mitigate or utilise. It is normally simply vented to the atmosphere.

In mines where the undisturbed coal seams contain large quantities of methane (termed gassy mines), ventilation alone does not provide sufficient control of methane concentrations to ensure safe operation. Moreover, so-called “gas-outs”, which are sudden releases of methane from the working face of the mine, can create safety hazards and disrupt production. These mines have therefore installed drainage systems, which extract methane from underground workings and roadways ahead of mining. Methane drained from mines in this way is typically at 40-85% concentration by volume (mixed with air, and in some cases also with carbon dioxide). This is referred to as *Medium Concentration Methane (MCM).* MCM may be simply vented to air, just as LCM is, but because of the much higher methane concentrations it may also be flared, or used locally for heat and/or electricity generation.

Currently, all underground coal mines in Australia employ ventilation, as the most economical method of gas control. Only a small number of very gassy mines employ gas pre-drainage, as a supplementary measure. Energy Strategies et al (1999) estimated that for the years 1996 to 1998, some 47% of the methane liberated from the 11 most gassy underground mines in Australia – all of which had drainage systems – was MCM.

Some important characteristics of mine drainage systems are:

- the gas is variable in flow rate, concentration and composition;
- the quantity of the gas drained from a single mine is generally insufficient for commercial utilisation; but

- in some areas it is possible for a gas collection system to cover a number of mines.

A number of factors affect the quality of the gas obtained by drainage, including:

- in-situ gas composition, content and variability;
- the characteristics of the gas collection system, including layout of drain holes, piping, and maintenance;
- lead time from pre-drainage to actual mining;
- coal production cycle fluctuations and stoppages.

Fugitive emissions of methane also occur from open cut mining operations. However, the nature of these operations means that methane is released in a very dilute and uncontrolled manner across the whole exposed face of coal in the mine. While, in general terms, coal seams amenable to open cut mining, being closer to the surface, will have lower in-situ methane concentrations than deeper coal seams which are only accessible by underground methods, fugitive methane emissions from open cut coal mines are nevertheless estimated to be significant.

There is no cost-effective way of controlling or mitigating methane emissions from open cut operations.

2.2.3 Quantities of fugitive methane emissions

The fugitive emissions from coal mining reported in the 1997 NGGI are summarised in Table 5. Mines can be classified into three groups:

- Gassy underground mines (Class A), which in 1997 accounted for 520.3 kt CH_4 or 66.7% of the total emissions from mines (779.8 kt CH_4);
- Less gassy underground mines (Class B), which in 1997 accounted for 19.6 kt, or 2.5% of total emissions from mines;
- Open cut mines, which in 1997 accounted for 239.9 kt, or 30.8% of total emissions from mines.

Class A mines offer the only practical potential for methane mitigation and capture. The concentration of methane in the ventilation air of Class B mines is too low for flaring or utilisation. While significant quantities of methane are produced in open cut mining, there is no cost-effective means of capturing it at present.

Apart from emissions from the mines themselves, a further 27.9 kt CH_4 was estimated to be emitted after mining from coal produced in Class A mines.

Table 5 Coal mining methane emissions, 1997 and 1998

	kt CH_4, 1997 (NGGI)	**kt CH_4, 1998 (Estimated)**
Gross emissions from Class A underground mines	NA	662.1
Capture from Class A mines	NA	100.0
Total net emissions from Class A mines	**520.3**	**562.1**
Total emissions from Class B underground mines	19.6	21.3
Total net emissions from underground mines	539.9	583.4
Post-mining emissions from underground coal	27.9	29.7
Emissions from open cut coal mines	239.9	254.9
Total coal mining emissions (net)	**807.7**	**868.0**

Note: 1998 estimates in this table differ from corresponding estimates in Energy Strategies et al (1999) due to use of more recent production data.

The emissions from Class A mines reported in the NGGI are the net of methane captured by existing methane recovery and utilisation projects: the gross emissions are somewhat higher. The actual gross value is not reported in the NGGI in order to preserve the commercial confidentiality of the capture data reported by the operators. The estimates for 1998 have been made for the purposes of this project, and are not reports from the project operators.

The uncertainties associated with the above estimates are high. The estimates are made by the use of algorithms which are derived from regression equations obtained from measurements made at samples of coal mines over two relatively short periods in the early 1990s. For the 1997 NGGI, the uncertainty is estimated to be at least 25%.

There is as yet no comprehensive set of actual measured methane emissions from underground mines. It is noteworthy that, in general, cumulative values from reports compiled by those companies which do continually monitor methane emission levels suggest higher emission quantities. This is discussed further below as a source of “methodological uncertainty” in projecting emissions.

The most accurate part of the coal mining emissions inventory is the amount of methane captured, since it tends to be metered as it goes into combustion engines or flares, and in the case of electricity generation can be cross-checked against electricity produced (taking into account the volumes of natural gas or other fuel that may be used for co-firing). The estimates of gross emissions and hence net emissions (gross less capture) are subject to much higher uncertainty.

It is possible that the development of new mitigation projects could actually lead to some increase in the estimate of gross emissions, for the following reasons:

- As more mines develop mitigation projects the effort put into emissions monitoring will increase, and as emissions are presently thought to be underestimated, this alone is likely to lead to an increase in the gross estimates;

- Some mitigation projects will result in increased safety and coal production. As such, the gross emissions of methane from the same mine will also increase (though there will still be a net reduction in emissions);
- Some mitigation projects may draw on methane from abandoned mines adjacent to the working main, and so effectively add to the NGGI a class of emissions that is not at present included.

These factors, which complicate estimates of the overall impact of mitigation, are summarised in the following algorithm:

$$\begin{array}{c}\text{Gross emissions}\\ \text{before start of}\\ \text{capture operations}\end{array} + \begin{array}{c}\text{Any additional emissions}\\ \text{due to capture operations}\end{array} - \begin{array}{c}\text{Methane}\\ \text{captured}\end{array} = \begin{array}{c}\text{Net emissions}\\ \text{(reported in NGGI)}\end{array}$$

2.2.4 Release of carbon dioxide from coal seams

The following estimates assume that seam gas consists of only a mixture of two gases, namely methane and carbon dioxide. Their proportions are described in terms of percent by volume (i.e. 20% CO_2 means 20% by volume CO_2, 80% by volume methane).

Most of the underground mines that have substantial CO_2 in their seams are Class A mines, but some Class B mines are also in this category. CO_2 concentration varies substantially from mine to mine, with a range of less than 10% to more than 90%.

Different studies have come up with different estimates of average CO_2 concentrations:

- Results from coal sample analyses by one producer indicated a range of 16% to 18% from that producer’s underground mines;
- Williams et al (1993) estimated an average 25% CO_2 concentration for the underground mines studied;
- Deslandes (1999) indicates an average of 29% for the underground mines surveyed (possibly including some contribution from emissions due to flaring and utilisation of captured methane).

To the knowledge of the authors, no studies have been undertaken for open cut mines.

For estimating CO_2 fugitive emissions from seam gas, it has been assumed that the CO_2 concentration for Classes A and B underground mines in NSW and Queensland is 20%. Zero CO_2 concentration has been assumed for all other classes of mine.

For a 20% CO_2 concentration, CO_2 fugitive emissions per tonne of methane emissions would be (using CH_4 density of 0.67606 kg/m^3, CO_2 density of 1.85917 kg/m^3):

$$(1.0 / 0.676) \times (0.2 / 0.8) \times 1.859 = 0.6875 \text{ tonne } CO_2$$

Hence for 1998, Class A (gross) + Class B + Post-mining CH_4 emissions =

$$662.1 + 21.3 + 29.7 = 713.1 \text{ kt } CH_4 \text{ (see Table 5).}$$

Therefore CO_2 fugitive emissions = 713.1 x 0.6875 = 490 kt CO_2.

Given that the 713.1 kt of CH_4 emissions related to underground coal production is equivalent to 14,975 kt CO_2, the inclusion in the inventory of 490 kt fugitive CO_2 would increase the fugitive emissions impact of underground coal production by about 3.3%.

2.2.5 Spontaneous combustion and slow oxidation

Coal and other carbonaceous materials exposed to the atmosphere during mining operations are subject to possible oxidation. At ambient temperatures, such oxidation occurs at a slow rate, and generates approximately 380 kJ heat per mole oxygen. If the rate of heat generation is greater than the rate of heat loss, the temperature of the material will rise. If unchecked, the heating could result in spontaneous combustion, which would produce CO_2, and small quantities of CH_4, at a much higher rate than slow oxidation.

Emissions from these sources are not included in the Australian NGGI at present, because of the large uncertainties. This is in line with current overseas practice, including in the USA.

For underground mines, due to very low occurrence rate, greenhouse gas emissions from these processes can be considered to be negligible.

For open cut mines, information in the literature mainly comes from studies conducted by CSIRO in the Hunter region (Williams et al, 1998). In estimating greenhouse emissions related to these processes, CSIRO assume that spoil piles are left “un-rehabilitated” for 30 years, and credit the total emissions in those 30 years to the first year of spoil disposal. Based on these assumptions, the following approximate emission factors may be derived:

- Slow oxidation = 0.5 kg CO_2 equivalent per tonne saleable coal production
- Spontaneous combustion (CO_2 + CH_4) = 12 kg CO_2 equivalent per tonne saleable coal production

Using these emission factors for 1998, with a total open cut saleable coal production of 154.8 Mt, the emissions would be:

- Slow oxidation = 77.4 kt CO_2-e
- Spontaneous combustion = 1858 kt CO_2-e
- Total = 1935 kt CO_2-e.

While these emissions would nominally be spread over 30 years, it would approximate the annual value (for the 30th year and on) if the area of spoil accumulated at the rate of production, and production remained fairly constant over a long time period.

However, this is not an appropriate assumption for most open cut operations in Australia. Most mines conduct some form of rehabilitation, and old spoils are often covered by new spoils. Therefore the surface area of spoil available to spontaneous combustion and slow oxidation may only change slightly from year to year, rather than always increasing as assumed above.

Internal investigations conducted by a producer indicate that there are very few reported incidences of spontaneous combustion at its mines. As such, it is felt that the above emissions may be over-estimated by a factor of four or even more: i.e. the annual value would be not 1935 kt CO_2-e but less than 480 kt CO_2-e. (Coincidentally, this value is close to the estimate for fugitive CO_2 in 1998).

If this were included in the inventory, it would increase the 1998 emissions from open cut coal mining by about 9%, from about 5,350 kt CO_2-e (254.9 kt CH_4 – see Table 5) to about 5830 kt CO_2-e.

2.3 Factors bearing on future emissions

2.3.1 Volume and mode of production

The NGGI methodology calculates fugitive emissions from the tonnage of raw (not saleable) coal produced, in each of the following categories of mine:

- Underground Class A mines: the same emissions formulae apply irrespective of whether these mines are located in NSW or Queensland;
- Underground Class B mines: the same emissions formulae apply irrespective of whether these mines are located in NSW, Queensland or Tasmania;
- Open cut mines: different factors apply to production in NSW (2.18 kg CH_4 per tonne), Queensland (0.82 kg CH_4 per tonne) and Tasmania (0.68 kg CH_4 per tonne).

For each of the above categories, two separate formulae are used and the average value is carried forward to the NGGI. The two formulae used are derived from two separate CSIRO studies. The NGGI Methodology Workbook 2.1 (National Greenhouse Gas Inventory Committee, 1997) requires the results to be averaged since the two approaches are equally valid and there is at present no reason to conclude that either is more accurate than the other. It should be noted that the surveyed average methane-intensities of mines in 1990 and in 1994 are embedded in the two formulae, so they are inputs rather than outputs. An *apparent* intensity value can then be derived by dividing the total emissions by the tonnage of coal produced, but this should not be confused with the *real* intensity value in that year. Historical changes in the apparent intensity value (shown in Figure 4), are an artefact of the interaction of the two formulae.

The methodology assumes that there are no fugitive emissions associated with coal produced in Victoria, SA and WA. Post-mining emissions are calculated only for coal produced in Underground Class A mines.

Table 6 summarises the effective emissions-intensities reported in the NGGI in 1997. The values are assumed to be the same in 1998.

Table 6 Methane-intensity of coal production, 1998

	Kg CH_4 per tonne raw coal
Underground Class A	17.20
Underground Class B	0.54
Open Cut	1.34
Post mining (Class A only)	0.77
Underground (weighted)	8.74
All coal (gross)	3.49
All coal (net)	3.12

Source: Derived from NGGI

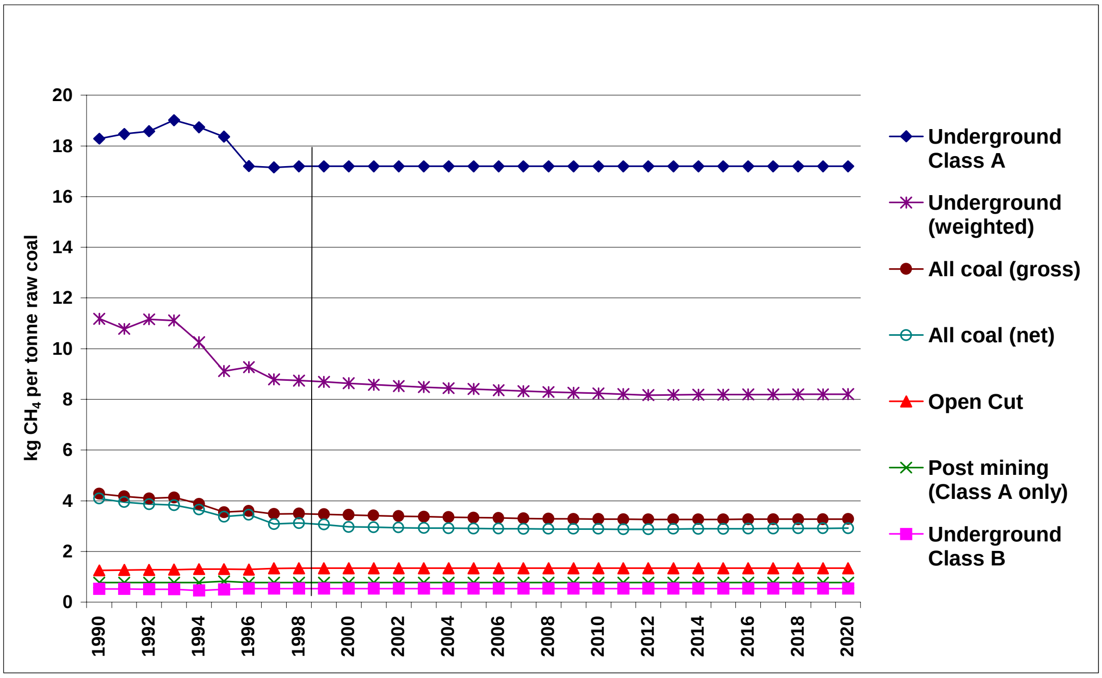
All else being equal:

- the greater the tonnage of coal produced, the greater the fugitive emissions; and;
- the greater the share of total production that comes from the more intensive modes of mining (Underground Class A in particular), the greater the emissions-intensity and hence the greater the emissions for the same tonnage.

Assuming that mining methods and gas draining practices will not change substantially in the future, then projecting the tonnage produced, the mode of production and to a lesser extent the state of production (for open cut mines) will mathematically determine the projection of the quantity of fugitive emissions.

Production of black coal increased at 4.3% per annum in the period 1990 to 1998. The latest ABARE projection of energy supply and demand in Australia contains a projection of net (saleable) coal production to 2015 (ABARE, 1999). ABARE projects a rate of increase of a little over 2.1% per annum in the period 1998 to 2007, and about 1.5% in the period 2007-15. This would increase the production of saleable coal from 219.0 Mt in 1997/98 to 298.4 Mt in 2014/15. This is used as the basis for a "Business as Usual" projection for coal production to 2020, on the assumption that the ratio of saleable to raw coal is 0.8, as it has been since the 1970s. Rates of change above and below this BAU trend line are also tested.

Figure 4 Fugitive methane emissions related to coal production (kg methane per tonne of black coal produced)



2.3.2 Gassiness of coal measures

At present, the NGGI does not take into account actual changes in the gassiness of the mines comprising each category of production. The average intensities in Table 6 are derived from a small number of CSIRO studies carried out in the early and mid 1990s.

The NGGI methodology actually anticipates the transition to direct reporting regime in the following terms:

> “No two mines have identical greenhouse gas emission characteristics. The best possible estimate of fugitive emissions would therefore be based on the sum of measured emissions from each individual mine. A potential source of such data, including in situ coal seam methane content and the concentration of methane in ventilation exhaust, is the data which many mines already collect for management purposes. However, these data have not in the past been reported to any central agency. The coal industry is considering such program beginning with the 1995 emissions year” (National Greenhouse Gas Inventory Committee, 1997:17).

On current indications, there is some possibility that direct monitoring could be at least partially in place for the 1998 NGGI, which will be compiled in early

2000. Once that is so, real changes in emissions intensity will begin to show up in the inventory.[2]

How then might the real methane intensity of coal mined change in the future? There are several factors at work, some suggesting a decrease in intensity and some an increase. The main factors are:

1. Share of production by mode: underground mining is on the whole more methane intensive than open cut mining (although some open cut mines, especially in NSW, are more methane-intensive than the least gassy underground mines);

2. Within each mode of production, the share likely to come from the more gassy coal regions. Deslandes (1999) compared the coal seam methane intensity of mines in the four major black coal basins. Mines in the southern coalfield of NSW (around Wollongong) are by far the most gassy. The Newcastle coalfield is the next most gassy, followed by the Hunter and then the Bowen (Queensland) coalfields.[3]

3. Within existing mines, the change in emissions profile over time: as deeper seams are worked, gassiness tends to increase.

4. The pattern of mine development and closure. On the one hand, mines which become dangerously gassy will be unproductive and will be closed. On the other hand, new underground mining areas will be deeper (hence more gas). Also, companies will have better technology to manage the gas, and possibly greater incentives to extract waste gas for electricity generation purposes. Hence a higher gross emission value may be more acceptable than it is now.

Figure 5 illustrates the share of gassy coal production for the three latest years that comes from three main groups: underground coal (weighted average of 8.7 kg CH_4 per tonne in 1998), NSW open cut (2.2 kg CH_4 per tonne) and Queensland open cut (0.8 kg CH_4 per tonne). The capacity of new projects listed by ABARE (1999) has also been analysed. The total tonnage represented in these projects is about 72 Mt per year, or about 26% of the output of these three groups of mines in 1999. These data suggest that the underground share of production would remain more or less constant, and the share of open cut production would shift to NSW, which is a more gassy region than Queensland. On this basis, the average methane intensity of all coal production would tend to increase slightly, assuming that the methane intensity of each group (underground, NSW and Queensland open cut) remained more or less constant.

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[2] It is noted that while compiling emissions data many mines tend to report emissions by volume, and various density values for methane, ranging from 0.616 to 0.714 kg/m^3, have been used to convert to mass. This density value needs to be standardised to minimise accounting errors.)

[3] NSW also contains two other regions: the Gunnedah region north of the Hunter, and the Western to the west of the Hunter. Deslandes (1999) does not report data separately for these regions, and it is assumed that they are similar to the Hunter in gassiness.

The location of projected underground mining capacity by region illustrated in Figure 6 suggests a further shift in the share of underground production from the most to the least gassy regions. All else being equal, this would lead to a major reduction in the weighted average methane-intensity of underground coal production.

To sum up, the data suggest:

- A weak trend to *increasing* methane intensity due to a projected rise in the NSW share of open cut mining production;
- A stronger trend to *reducing* methane intensity due to a projected shift in underground coal production to the less gassy coalfields;
- A trend to *increasing* methane intensity due to the development of deeper coal measures at new mines and the working of deeper seams at existing mines.

All in all, it would be reasonable to assume a constant methane-intensity under business as usual, but to examine the impacts of both small increases and small decreases in average intensity.

Figure 5 Current production and capacity of mines and projects, by mining method

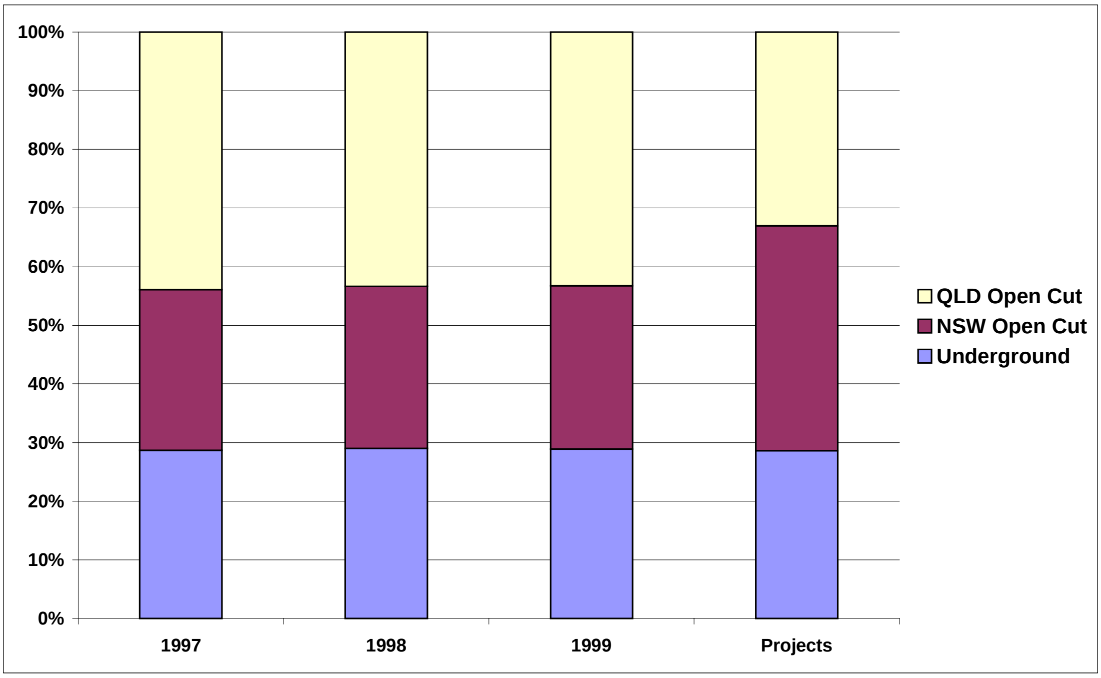
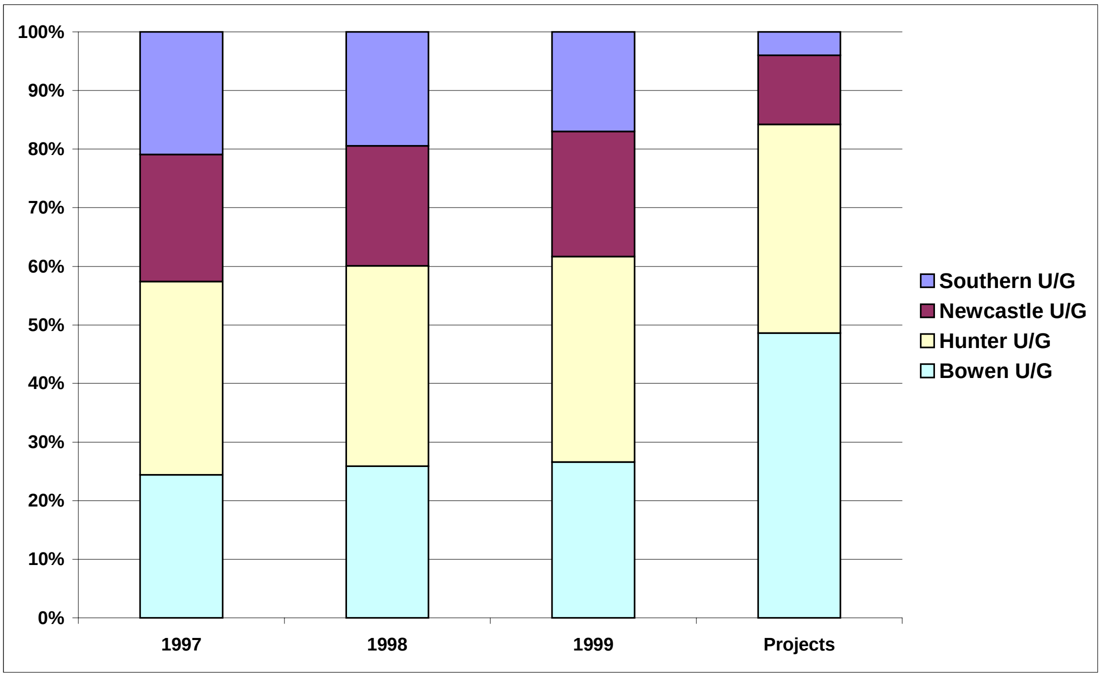


Figure 6 Current production and capacity of mines and projects by region, underground mines



2.3.3 Methane capture issues

Three of the authors of the present study recently carried out a review of the potential in Australia for reducing waste coal mine gas (WCMG), i.e. fugitive emissions from coal mines, through two broad groups of options (Energy Strategies et al 1999):

- "mitigation" projects, where the captured methane is flared or otherwise oxidised. The CO_2 emitted has 1/21 times the Global Warming Potential of methane, so there is a net reduction of 87% in the CO_2-equivalent impact of the emissions compared with venting;
- "utilisation" projects, where the energy released from oxidation of the WCMG provides useful heat or generates electricity. The *additional* greenhouse benefit of utilisation compared with mitigation alone depends on the greenhouse gas intensity of the fuel or electricity displaced. The increase in greenhouse mitigation benefit is of the order of 10% for projects which produce useful heat, and 25-35% for projects which generate electricity.[4]

There are examples of these approaches in Australia:

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[4] The relationship between methane capture, electricity generation potential and CO_2 impact is a complex one, and varies from site to site, and from year to year for the same generation plant, according to variables such as the need for top-up natural gas. Some typical values are illustrated in Table 4. For further details, including discussion of costs, see Energy Strategies et al (1999).

- Mitigation: WCMG is flared at Shell Australia's German Creek colliery in Queensland;
- Utilisation for electricity: WCMG gas engines generating electricity are installed at BHP's Appin and Tower collieries in NSW. A pipeline to bring additional WCMG from West Cliff colliery to the Appin gas engines has recently been constructed;
- Utilisation for heat: a pipeline to feed WCMG from Powercoal's Wyee Colliery to the boiler air intakes at Vales Point power station (owned by Delta Generation) is under consideration.

Existing projects captured about 100 kt CH_4 in 1998, so reducing fugitive emissions from mines from a gross value of about 968 kt CH_4 to a net value of 868 kt CH_4 (see Table 5).[5] The likely capture by projects already operating or under construction is termed the "BAU generation" scenario (although it also includes the impact of the German Creek flaring project). Under this scenario, methane capture increases to about 133 kt/yr in 2000, and then rises gradually to 139 kt/yr by 2020.

There is considerable further potential for WCMG capture beyond the BAU scenario. Most of this is likely to involve electricity generation, but heat utilisation projects and in some cases flaring alone are also possible. Energy Strategies et al (1999) examined two scenarios in detail:

- A "medium generation" scenario, in which generation at existing WCMG projects is expanded, projects currently under investigation are completed and an additional 400 GWh per annum of WCMG generation is developed by 2012. This gives an additional 770 GWh per annum beyond the BAU case;
- A "maximum" scenario, which assumes a further 620 GWh per annum of WCMG generation above the level of the medium scenario, or 1,390 GWh per annum beyond BAU.

The extent to which this potential is realised will depend on a number of factors, including the extent of incentives for generation. The "medium" estimate of new WCMG generation may correspond to a scenario in which electricity prices are relatively low, there is a moderate level of incentive for reducing greenhouse gas emissions, and mitigation options take precedence over utilisation.

The potential for additional methane capture is estimated at about 145 kt CH_4 per annum beyond BAU under the "medium generation" scenario, and 270 kt CH_4 per annum beyond BAU under the "maximum generation" scenario.

If the maximum electricity generation potential were taken up, there would be only limited scope for other mitigation options. WCMG falls into the categories of either MCM or LCM. The majority of WCMG emitted is LCM, but at present there are fewer options for cost-effective capture and use than for MCM.

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[5] These values are somewhat different from those published in Energy Strategies et al (1999), since later data has since become available.

The only LCM utilisation project currently under consideration is Wyee/Vales Point.

The main technical options for electricity generation from WCMG are:

1. Gas engines: these are a proven technology and are operating successfully at Appin and Tower collieries;
2. Lean burn gas turbines: these are readily available and one unit is currently being installed by EDL at Appin for a 12 month trial operation in 2000;
3. Steam cycle generators powered by regenerative thermal oxidation; and
4. Steam cycle generators powered by catalytic conversion.

Regenerative thermal oxidation and catalytic conversion of WCMG on a commercial scale are currently being demonstrated, but they are still under development and their costs are uncertain. The major potential advantage of these technologies are that they can operate on a gas mix of up to 90% LCM, whereas gas engines typically use 90% MCM and turbines 67-75% MCM. Therefore they represent the possibility of utilising more of the large amounts of LCM emitted, albeit at a higher cost.

The study concluded that it is unlikely that the conditions that led to the development of the existing WCMG projects will be repeated, particularly while electricity prices remain low. It discussed the additional drivers that may be required to ensure that the projects currently under investigation are implemented, existing projects operate to their maximum capacity and the potential for new projects is realised.

The effects of the “BAU generation”, “medium generation” and “maximum generation” scenarios from Energy Strategies et al (1999) are included in the range of projections in the present study.

2.3.4 Methodology factors

The fugitive emissions inventory is obviously dependent on how the NGGI is calculated as well as on actual physical changes in emissions. This section discusses the source and magnitude of uncertainties in the methodology and how these could affect the projections.

Estimation of fugitive methane

Underground mines need to continuously monitor the methane concentrations in the ventilation air and methane drainage system (if installed), so the most accurate way of compiling the inventory of fugitive emissions from underground mines is for all mines to report that data. Deslandes (1999) sent survey forms to all mines, and received replies from mines representing 90% of Australian raw coal production (317 Mt: brown coal included) . It is not clear from Deslandes' (1999) report:

- Whether all the underground black coal mines responded, and what proportion of total underground production the reporting mines represented;
- Of those that responded, which ones reported actual monitored data, and which ones reported an estimated value or relied on the default methane emissions factors provided by Deslandes (1999).[6]

The total fugitive emissions reported by Deslandes (1999) for the mines surveyed was 16.3 Mt CO_2-e, of which 73/77 (15.45 Mt CO_2-e) was methane and the rest (0.85 Mt) was carbon dioxide. This gives total CH_4 emissions of 15,450/21 = 736 kt, compared with the NGGI estimate for 1998 of 868 kt. However, Deslandes' (1999) estimate does not cover all of production, and appears to exclude post-mining emissions (about 30 kt CH_4). If put on a completely comparable basis, the estimates may well be close. However, this cannot be confirmed without further research. For the time being, this aspect of the methodology is subject to uncertainty.

The uncertainty regarding fugitive emissions from underground mines is likely to be reduced through direct reporting. However, the emissions from open cut mines, which are estimated to account for over one quarter of gross methane emissions, are difficult to monitor continuously. The NGGI estimates will continue to rely on the formulae derived from previous research projects, and reducing the uncertainty will depend on the rate of further research.

Inclusion of fugitive carbon dioxide

Fugitive carbon dioxide from coal seam gas is not at present included in the NGGI. There appears to be sufficient basis for now including it. The method proposed earlier relies on two uncertain values: the tonnage of methane seam gas emitted (as calculated using the NGGI methodology) and the concentration of CO_2 in the vented seam gas. This gave an estimate of 490 kt CO_2 for underground mines. Deslandes (1999) reports an estimate of 850 kt for all mines (possibly including some contribution from emissions due to flaring and utilisation of methane).

Therefore if CO_2 from coal seam gas is added to the fugitive inventory, the impact on the NGGI could be in the range of 0.5 to 0.8 Mt CO_2-e.

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[6] For underground Class A mines Deslandes (1999) gave a default factor of as 2.3 kg CH_4/tonne. It is thought that the factor should have been higher by a factor of six, which would bring it much closer to the 17.2 kg/tonne derived from the NGGI. Use of the default factor would have led to under-reporting, but since the great majority of the emissions were directly reported, any under-reporting would be limited.

Spontaneous combustion and slow oxidation

These factors are subject to a high degree of uncertainty. As discussed above, if included in the fugitive inventory the impact on the NGGI could be about 0.5 Mt CO_2-e. Reducing the uncertainty will depend on the rate of further research.

Abandoned mines

When measuring emissions from open cut mines in the Hunter Valley in 1991, Williams et al (1993) made an indirect measurement of gas from a recently abandoned underground mine. This mine appeared to be emitting a rate of about 44 kt CH_4 per annum, or about 0.9 Mt CO_2-e from this one mine alone.

The emissions from this or other abandoned mines are not included in the inventory, because of lack of direct emissions data and the uncertainty of the persistence of emissions over time. This is in line with current overseas practice, including in the USA. However, some emissions from abandoned mines could be indirectly added to the NGGI. One methane capture project currently under consideration may capture more methane than is being reported from the working mine where it is to be located, because it will draw on methane from abandoned mines adjacent to the working mine, and so effectively add to the NGGI a class of emissions that is not at present included. This additional amount will be the difference between the current monitored amount and the amount to be captured, so it remains uncertain.

2.3.5 Emission projections

The following projections assume that mining methods and gas draining practices will not change substantially, that pre-mining drainage, such as extraction of coal bed methane from surface holes, will not be introduced on a large scale and that novel mining techniques that may result in less fugitive emissions, such as highwall mining, will not be widely adopted.

Three main projection scenarios for fugitive methane emissions from coal mining have been developed:

- A MIDPOINT emissions projection comprising BAU coal production growth (see Figure 9), no change in the average methane-intensity of any of the coal regions (see Figure 10), and realisation of the “medium generation” scenario for methane capture;
- A HIGHEST emissions projection comprising higher than BAU growth in coal production, an increase in the average methane intensity of the coal regions, and realisation of the “BAU generation” scenario for methane capture (i.e. existing projects only);
- A LOWEST emissions projection comprising lower than BAU growth in coal production, a decline in the average methane intensity of the coal regions, and realisation of the “maximum generation” scenario for methane capture.

Figure 7 illustrates that in the BAU production scenario, production increases at a much lower rate than in the recent past. This is so even for the highest production scenario. Figure 8 illustrates how the main coal regions and modes of mining would contribute to total black coal production.

These three scenarios are illustrated in Figure 11. Several combinations of production growth, methane intensity change and methane capture rates are illustrated. The three main scenarios are indicated with arrow-heads. Some of the key features are summarised in Table 7. In the Midpoint scenario, the rate of development of methane capture projects keeps pace with production increases until 2010. In the Lowest scenario, the absolute level of emissions in 2020 is still 7% lower than in 1990.

Table 7 Summary of projection scenarios

Scenarios	1990 Mt CO_2-e	2010 Mt CO_2-e	2020 Mt CO_2-e	Change, 1990-2020 Mt CO_2-e	Change, 1990-2020 %
Highest	16.8	23.1	28.9	12.1	72%
Midpoint	16.8	18.1	21.3	4.5	27%
Lowest	16.8	13.8	15.6	-1.2	-7%
Highest cf Midpoint	0	5.0 (+28%)	7.6 (+36%)		
Lowest cf Midpoint	0	-4.3 (-24%)	- 5.7 (-27%)		
Maximum range	0	9.3	13.3		

Figure 7 Historical and projected rates of change in black coal production, 1990-2020

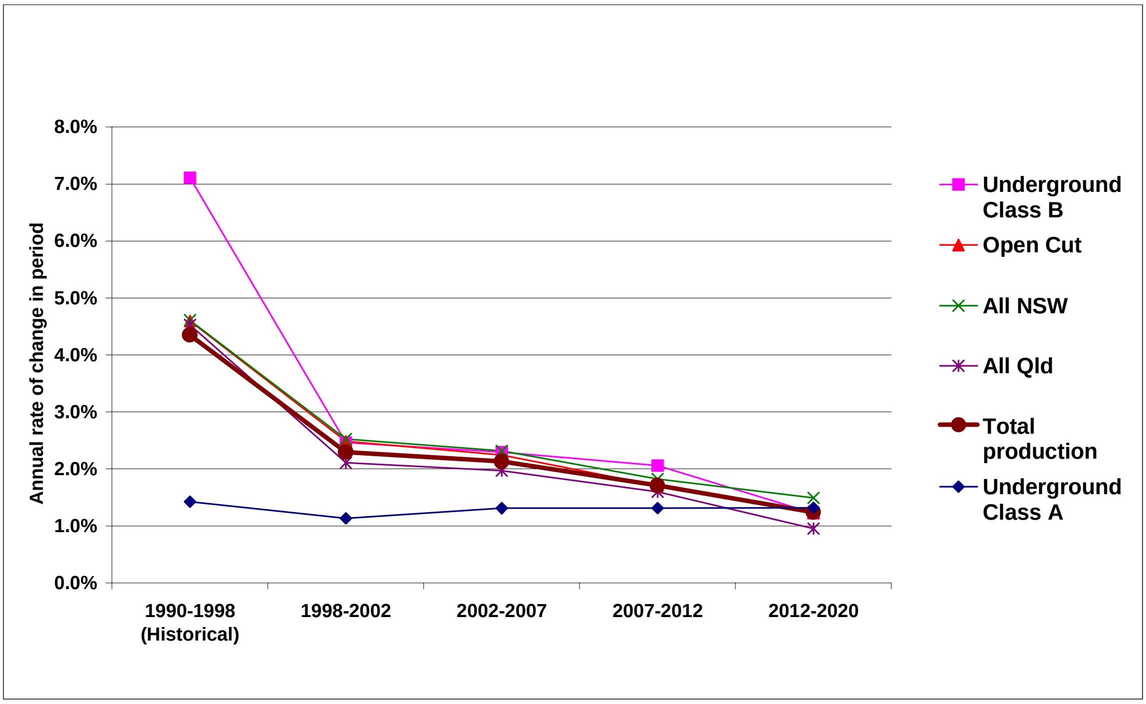


Figure 8 Historical and projected coal production from main regions, 1990-2020

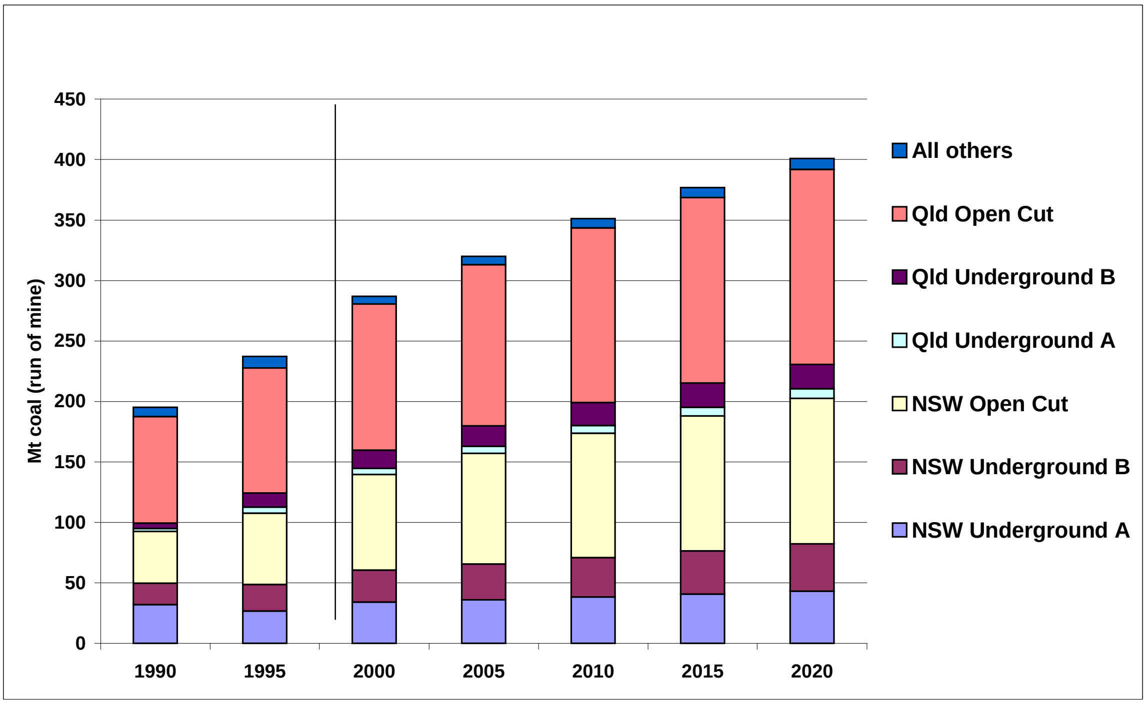


Figure 9 Production scenarios for black coal, 1990-2020

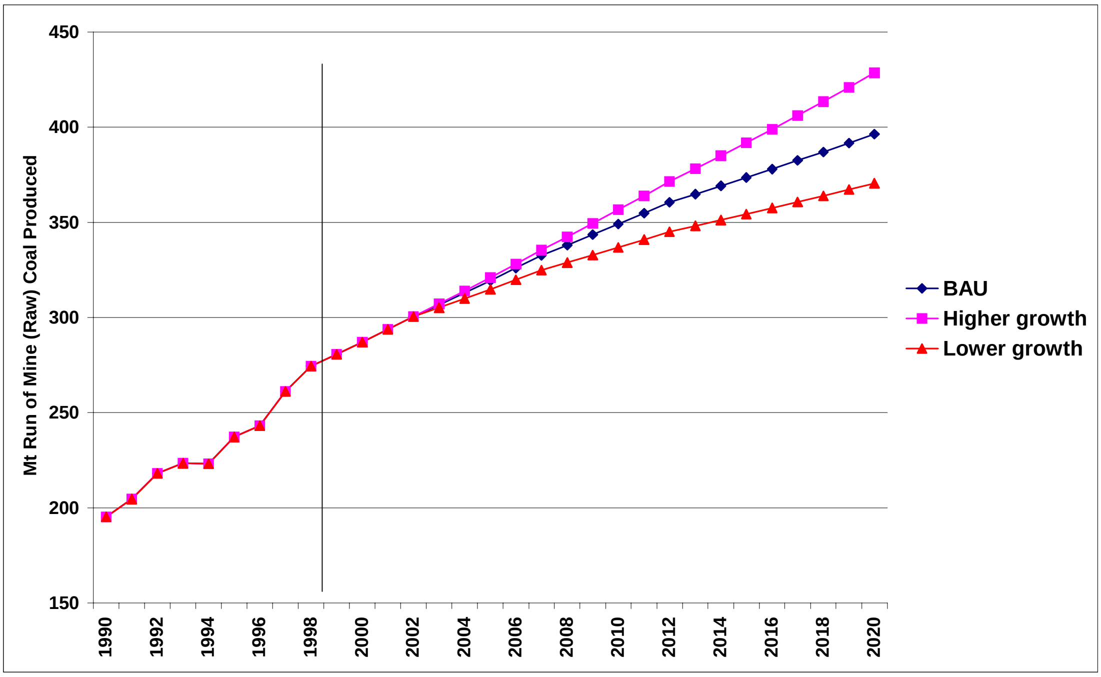


Figure 10 Methane intensity scenarios for black coal, 1990-2020

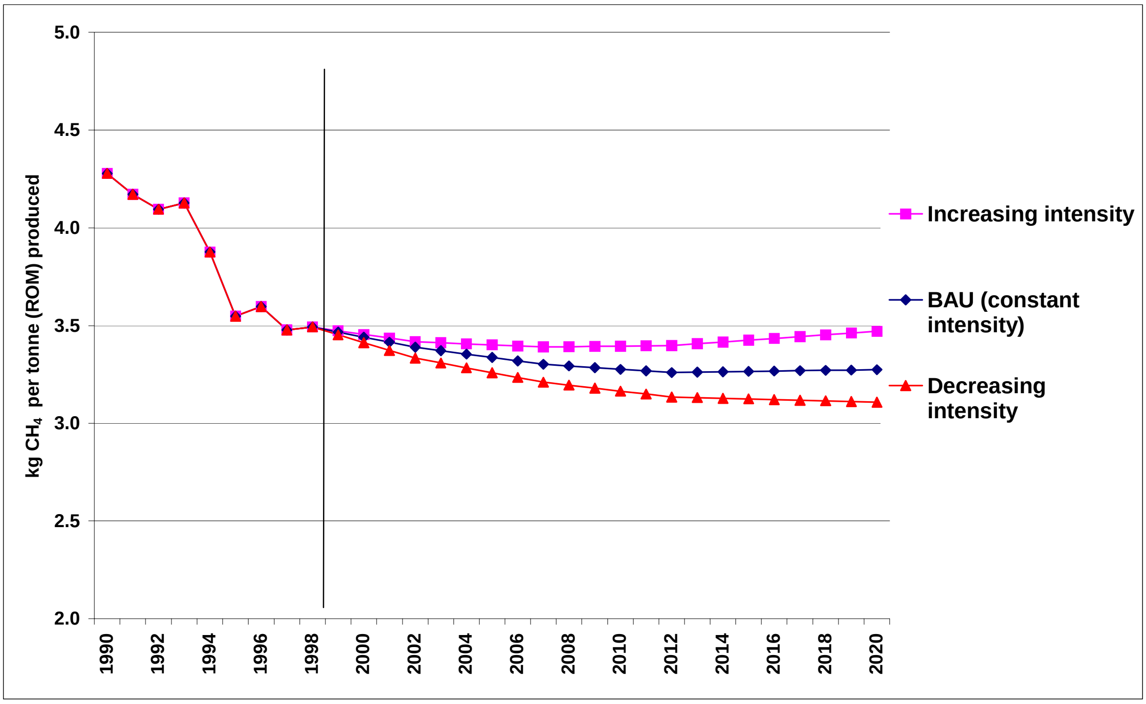
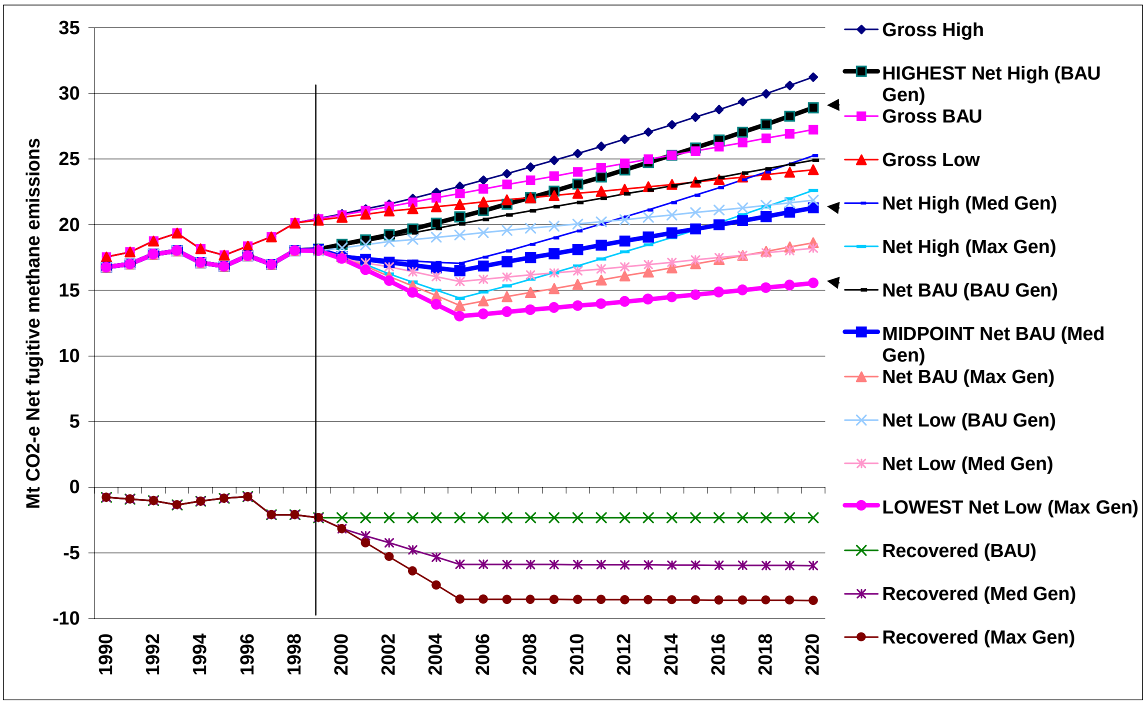


Figure 11 Projected fugitive methane emissions from coal mining, 1990-2020



3 EMISSIONS FROM OIL AND GAS

3.1 Inventory-wide contribution

Oil and gas related activities are a major source of greenhouse gas emissions, falling into two major categories:

- combustion emissions, comprising CO_2 with trace quantities of other GHGs, mainly associated with energy used in the processing of crude oil and raw natural gas; and
- fugitive emissions, comprising CO_2 and methane, plus trace quantities of nitrogen, derived from a wide variety of sources and emission processes.

The major sources of combustion emissions, with quantities taken from the 1997 NGGI, are shown in Table 8.

Table 8 Combustion related emissions associated with oil and gas production and processing, 1997 (Gg)

Source/activity	**Greenhouse Gas**			
	CO_2	**CH_4**	**N_2O**	**CO_2-e**
Petroleum refining	6,392	0.10	0.05	6,410
Oil and gas production and field processing	6,788	0.96	0.01	6,811
Gas transmission	437	0.07	0.00	438
Gas distribution	134	0.02	0.00	134
Total	**13,751**	**1.15**	**0.06**	**13,793**

It can be seen that petroleum refining and gas processing are by far the largest sources of emissions. Oil refineries use energy to distil crude oil and for the various chemical processes required to produce petroleum products which meet market specifications in terms of octane number, cetane number, sulfur content etc. The largest user of gas processing energy is the North West shelf liquefaction plant, where LNG is produced for export. However, other plants which separate raw natural gas into its various components and supply gas to market specifications, located adjacent to the Gippsland, Cooper Basin and other gas fields supplying the domestic market, also use substantial quantities of energy.

The NGGI does not separately account for emissions arising from the use of energy in the transportation of crude oil and petroleum products. These emissions are included in the national totals of emissions from the various transport modes, with the exception of emissions associated with international transport of crude oil, which are unallocated to any national inventory. The emission sources which are included in the national inventory are domestic shipment of crude oil (mostly by sea and pipeline, plus a small amount of rail and road) and distribution of petroleum products (by sea, pipeline, rail and road, all in significant volumes).

The sources of fugitive emissions, with quantities taken from the 1997 NGGI, are shown in Table 9.

Table 9 Fugitive emissions associated with oil and gas production and processing, 1997 (Gg)

Source/Activity	**Greenhouse Gas**			
	CO_2	**CH_4**	**N_2O**	**CO_2-e**
Exploration	8	0.1	0.0	10
Crude oil production	0	0.3	0.0	6
Crude oil transport (domestic)	0	0.3	0.0	6
Crude oil refining and storage	222	0.6	0.0	235
Petroleum product distribution *	0	0.0	0.0	0
Natural gas production and processing	0	2.0	0.0	42
Gas transmission	0	4.9	0.0	103
Gas distribution	9	165.2	0.0	3,478
Venting	2,570	125.6	0.0	5,208
Flaring	2,724	33.4	0.1	3,456
Total	**5,533**	**332.3**	**0.1**	**12,542**
Total in Gg CO_2-e	**5,533**	**6,978**	**31**	

*NOTE: Fugitive emissions from this source comprise only indirect greenhouse gases (NMVOCs)

It can be seen that four sources, venting, flaring, gas distribution and oil refining, account for the great bulk of the fugitive emissions from the oil and gas industries. It can also be seen that, in terms of CO_2-e emissions, CO_2 and methane make roughly equal contributions.

Most of the various sources of methane emissions are very diffuse – in the main leaks from pipelines systems. Consequently, there are no opportunities to mitigate methane emissions by oxidation, whether by controlled combustion to extract useful energy or by flaring.

3.2 Venting from oil and gas production facilities

Venting of both CO_2 and methane currently occur in Australia. We consider them separately.

3.2.1 Venting of carbon dioxide

All raw natural gas, i.e. natural gas as it comes out of the ground, is a mixture of gases. While methane (CH_4) is the major component, ethane (C_2H_6) is usually also present. Many gas fields also contain higher hydrocarbons, such as propane, butane, pentane etc., which are either liquid at atmospheric pressure, or can be liquefied under relatively low pressures. These are collectively termed natural gas liquids. Natural gas processing largely involves separating the stream of raw gas into its various hydrocarbon constituents, each of which has a different market. Sales gas consists largely of methane and, if no higher value market as a petrochemical feedstock can be found, ethane also. Only trace amounts of the heavier hydrocarbons are included.

Typically, raw gas also contains non-hydrocarbon components, the most common of which are CO_2 and nitrogen. Nitrogen is normally present in relatively small concentrations and is left in the sales gas. However, some gas fields contain quite high concentrations of CO_2. For technical reasons related to its performance as a fuel, there is an upper limit on the acceptable concentration of CO_2 in sales gas, which is normally around 2% by volume (equivalent to 2% on a molecular basis for a perfect gas). Where gas fields contain much more CO_2 than this, the gas must either be mixed with gas from other fields having very low CO_2 concentrations, to achieve the acceptable limit, or, if this is not possible, stripped out of the raw gas at the processing plant, using one of a several available processes referred to as acid gas stripping (other acid gases, notably H_2S, sometimes present in small quantities, must also be removed). The stripped CO_2 is normally vented to the atmosphere, and this is the major source of vented CO_2.

Where natural gas is being liquefied, for export as LNG, the upper limit on acceptable CO_2 concentration is much lower than 1.0%, mainly because of technical constraints in the liquefaction process. Stripping and venting therefore occurs at most liquefaction plants.

Obviously, whether CO_2 venting occurs at all at a natural gas processing plant and, if it does, the quantity of CO_2 vented, will depend on the concentration of CO_2 in the raw gas stream being processed. In Australia, as in other natural gas producing countries, raw gas concentrations of CO_2 vary between gas fields across a wide range. There can be no sound basis for assuming any particular average concentration on a national basis. For this reason, the NGGI figures for this emission source are derived from the annual survey of its member companies conducted by the Australian Petroleum Production and Exploration Association (APPEA, 1997). For the same reasons, emissions can only be projected on a field by field, or project by project basis, where the data needed to do this are available.

We analyse and project emissions from sources of vented CO_2 under four main groupings: the North West Shelf, the Cooper-Eromanga Basin fields, other gas fields supplying markets in southern and eastern Australia, and potential new LNG projects.

North West Shelf

The North West Shelf plant is currently one of the two main sources of vented CO_2, the other being the Moomba plant (see below). Venting also occurs at some small fields in the south east of SA, but because production from these is so small, the emissions can be ignored for the purposes of this study, notwithstanding the high rates of emission, in terms of tonnes per GJ produced. Data on the quantities of CO_2 vented from the North West Shelf each year are not available. We have therefore derived an approximate estimate using other data, as follows.

- Assume that the CO_2 content raw North West Shelf gas is 2.5% on a volume or molecular basis. According to Felton et al. (1993), raw gas from one North Rankin well, one of the major field forming part of the project, has a CO_2 content of 3.5% on a volume or molecular basis. However, it is understood that other wells and other fields in the project have somewhat lower CO_2 concentrations, and hence the value of 2.5% has been assumed.
- Assume that all CO_2 is stripped and vented from that fraction of North West Shelf production which is liquefied and exported, i.e. CO_2 content of LNG is zero. Combining this assumption with the above percentage CO_2 content of raw gas yields a venting rate of approximately 0.07 tonne CO_2 per tonne of LNG produced.
- Assume that no CO_2 is stripped from that fraction of North West Shelf production which is supplied to the domestic WA market, i.e. all venting is linked to the production of LNG.
- Assume that the existing liquefaction plant will continue to operate at the current rate of 7.5 Mt per year throughout the projection period and that the rate of venting will also remain constant over the period.

These assumptions apply for each of the projection scenarios described below.

Cooper/Eromanga Basin

The other major source of vented CO_2 in southern and eastern Australia at present is the Moomba plant, which processes gas from the fields of the Cooper and Eromanga Basins for supply to NSW and SA. This gas producing region contains a large number of medium to small size fields, some of which contain high concentrations of CO_2. The mix of fields from which gas is being produced changes over time, as some fields are depleted and others are discovered. This means that the rate at which CO_2 is vented also changes over time, depending on the CO_2 content of the mix of producing fields at the time.

Data on the quantities of CO_2 vented from Moomba each year are not available. We have therefore derived an approximate estimate using other data, as follows.

- Assume that Moomba and the North West Shelf are the only sources of vented CO_2.
- Assume that CO_2 is vented from the North West Shelf at the rate of 0.07 tonne CO_2 per tonne of LNG produced (as explained above).
- Assume that gas supplied from Moomba is equal to the sum of all gas consumed in NSW and SA.

CO_2 vented from Moomba is then calculated as the difference between total venting and the estimated venting from the North West Shelf. When the quantity vented is related to gas produced, year by year from 1991 to 1997, it is found that the ratio varies between 8.7 and 9.4 kt CO_2/PJ of gas produced.

Other gas fields in southern and eastern Australia

It is assumed that there is currently no significant CO_2 venting from any of the other gas fields supplying markets in southern and eastern Australia, and that this will remain the case throughout the period covered by this study, with the single exception of the Kipper gas field in the Gippsland Basin. This as yet undeveloped field has a CO_2 content of approximately 10.4% on a molecular basis (Victorian Department of Natural Resources and Environment, *pers. comm.*). We assume that this equates to 6 kt CO_2 per PJ of gas produced. (This figure is somewhat dependent on the assumptions made about the content of higher hydrocarbons, nitrogen and other minor constituents of raw gas.) If it is also assumed that content would be reduced to approximately 1 kt per PJ, to meet quality standards for sales gas, then the venting rate would be approximately 5 kt per PJ.

Reserves of gas in Kipper have been put at 600 x 10^9 ft^3 (Victorian Department of Natural Resources and Environment, 1999), which is equivalent to approximately 17 x 10^9 m^3 or 660 PJ.

New projects in northern and western Australia

A number of large gas fields have been discovered off the coast of north western Australia, which could be developed, either as export LNG projects or to supply domestic Australian markets, during the study period. Some of these fields contain significant concentrations of CO_2 and, therefore, if developed, could give rise to additional venting emissions. Three possible projects are currently subject to relatively intense design and planning activity: a doubling of capacity on the North West Shelf, Gorgon, and Bayu Undan. As yet, no decisions have been made to proceed with any of these projects.

In its projections ABARE has assumed that exports of LNG will grow from 7.5 Mt p.a. (the current level) to 23.5 Mt p.a., an increase of 16 Mt p.a., over the period 2005 to 2011. This growth is equivalent to two new projects of 8 Mt p.a. each (the economically optimal size for remote offshore developments of this kind). However, ABARE has no view as to which of the potential projects are the more likely to proceed.

The three projects mentioned above differ in their CO_2 contents.

Gorgon contains nearly 17% CO_2 on a molecular basis (Felton et al., 1993). We assume that any development of Gorgon will be as an export LNG project, and that therefore all CO_2 will be stripped. 17% by volume, given the content of minor constituents, equates to approximately 10 kt/PJ natural gas produced or 500 kt/Mt of LNG produced.

We assume that the gas processed at a second North West Shelf plant will vent CO_2 at the same rate as has been assumed for the current plant, i.e. 70 kt/Mt of LNG.

The Bayu Undan fields, located in the Zone of Cooperation between Australia and East Timor, contain significant quantities of liquid hydrocarbon, as well as gas. They also have a very low concentration of CO_2. Current planning is for a liquids only development, with gas being reinjected (Phillips Oil, *pers. comm.*). If development proceeded on this basis, no CO_2 would be vented. It would be anticipated that at a later date the gas reserves would also be extracted, and if this development were as LNG, there would probably be some small venting of CO_2. However, it is possible that development of the gas reserves may be directed towards domestic markets in the NT, and possibly Queensland, in which case no CO_2 would be vented at the processing plant, as there would be no need to strip CO_2 to meet the specifications for pipeline quality gas.

3.2.2 Venting of methane

There are several sources of vented methane (APPEA, 1997):

- methane which is entrained with CO_2 in the acid gas stripping process and vented with the CO_2. According to inventory data published by APPEA (1997), the mass of methane vented in this way has consistently averaged between 1.7% and 1.9% of the mass of vented CO_2 over recent years, and has accounted for roughly 40% of total vented methane;
- methane released from compressor seal gas systems;
- other process emissions.

For the purpose of preparing projections, we have analysed methane vented in association with CO_2 separately from the other sources.

Acid gas stripping

In preparing projections of emissions from this source the following assumptions have been made.

- For all existing gas processing plants with acid gas stripping, methane vented is equal to 1.8% by mass of vented CO_2 in each projection year, i.e. from 1998 onward. This assumption implies that there are few opportunities to modify existing acid gas stripping facilities to reduce methane emissions.
- For acid gas stripping at new gas processing plants, methane vented is equal to 1.5% by mass of CO_2 vented from these plants. This assumption allows for improved performance through technological improvements in the new plants.

All other sources

While in general it would be expected that quantities of methane vented from other emission sources would be related in a very general way to the total quantity of gas produced, there are no reasons to expect that any such relationship would be either simple or stable. There is a wide variety of activities which give rise to methane venting, and volumes vented may vary widely between gas fields, depending on many different design and operating characteristics of each field. Nevertheless, in the absence of any better means to project emissions from this source, the ratio of emissions to total gas production has been used as a key parameter.

During the last three inventory years this ratio was between 0.067 and 0.065 kt CH_4 per PJ natural gas produced, with a gradually declining trend.

3.2.3 Emissions projections

All vented CO_2 and most vented methane is released at gas processing plants where CO_2 stripping occurs. Volumes vented depend on both the volume of raw gas which passes through the stripping process and the quantity of CO_2 stripped per unit of gas.

Stripping adds to the cost of natural gas, and is only undertaken if it is technically necessary, either to meet quality specifications for pipeline gas, or to allow liquefaction. It is currently undertaken, for one or other of these reasons, for about half the raw gas produced in Australia. It is not, and cannot be, known at this time which individual gas fields will be producing in 2020. It is therefore not possible to say how much of Australia's raw gas production in that year will require CO_2 stripping, or what the volume stripped per unit of gas produced will be. It is clear, however, that venting volumes will be determined by:

- primarily, whether or not certain gas fields with high CO_2 levels are developed, and
- secondarily by the concentrations of CO_2 and methane.

We have constructed three projection scenarios which are composites of both factors. Three points should be noted.

- The main, though not the only difference between the "High" and the "Low" scenarios is whether or not certain high CO2 gas fields, notably Gorgon and Kipper, are developed.
- No scenario assumes any policy intervention to encourage or mandate emission reductions. However, for reasons which are discussed in Chapter 4, a "with policy" scenario will probably be very similar to the "Low" scenario specified here.
- The central scenario is described as "Middle" not "BAU", because all three are consistent with "business as usual" operations of gas industry, with the

primary driver for the differences between scenarios being different price levels for gas, both within Australia and internationally (for LNG).

The specifications of the three scenarios are as follows.

Middle scenario

Total domestic consumption of natural gas, i.e. production less LNG exports, is as projected by ABARE up to 2015 and continues to grow at the same linear rate for the remaining five years.

For gas supplied from Cooper/Eromanga Basin fields, the following assumptions are used.

- The rate of venting will be 9.0 kt/PJ throughout the period. This rate is the average of the rate over recent years. Assuming a constant future rate implies that the mix of high and low CO_2 fields will remain roughly constant. In the absence of detailed knowledge about the size and CO_2 content of each field, and of Santos' development plans for the Basin as a whole, there is no way to assess the validity of this assumption or the probability of it being wrong by any given amount.
- Production of gas from the Cooper Basin equals total gas consumption in NSW and SA, as projected by ABARE, for each year up to and including 2001, and thereafter stays constant at the level for 2001, which is 262.5 PJ, for the remainder of the study period. This assumption implies that growth in NSW demand after 2001 will be supplied from either Victorian gas field, i.e. Gippsland, which has larger reserves than the Cooper Basin, or from new sources, such as coal seam methane.

For gas produced from the Kipper field, production at a rate of 30 PJ p.a. starts in 2010, and CO_2 is stripped and vented at a rate of 5 kt/PJ.

Two new LNG projects are developed according to the timetable implied by the ABARE projections, with the second North West Shelf plant being the first, and Gorgon the second.

Development of Bayu-Undan emits no vented CO_2.

For methane vented in association with acid gas stripping, methane vented from existing plants is 1.8% by mass of vented CO_2, and for new plants is 1.5%.

For other sources of vented methane, the ratio of methane emitted to gas produced is 0.065 kt/PJ in 1998 and falls by 0.5% per year in each subsequent year.

High scenario

Growth in total domestic gas consumption is 25% higher than in the "Middle" scenario.

For Cooper/Eromanga Basin gas, production continues to rise steadily from 2001, reaching a level in 2020 which is 25% higher than in the Middle case, while the ratio of emissions to production remains unchanged at 9.0 kt/PJ.

For Kipper, production at a rate of 50 PJ p.a. starts in 2005, and CO_2 is stripped and vented at a rate of 5 kt/PJ.

For new LNG projects, the second new project, assumed to be Gorgon, is brought forward by three years compared with the Middle scenario, so that both new projects start in 2005 and reach full capacity by 2008. An LNG project using Bayu Undan gas starts production in 2016 with emissions of 20 kt/Mt LNG.

For methane vented in association with acid gas stripping, the same assumptions are used as in the Middle case.

For other sources of vented methane, the ratio of methane emitted to gas produced stays constant for the whole projection period.

Low scenario

Growth in total domestic gas consumption is 25% lower than in the "Middle" scenario.

For Cooper/Eromanga Basin gas, production falls steadily from 2001 on, reaching a level in 2020 which is 25% lower than in the BAU case, while the ratio of emissions to production remains unchanged at 9.0 kt/PJ.

Kipper is not developed during the study period.

For new LNG projects, the second North West Shelf project is developed as in the Middle case, but Gorgon does not proceed.

Development of Bayu-Undan emits no vented CO_2.

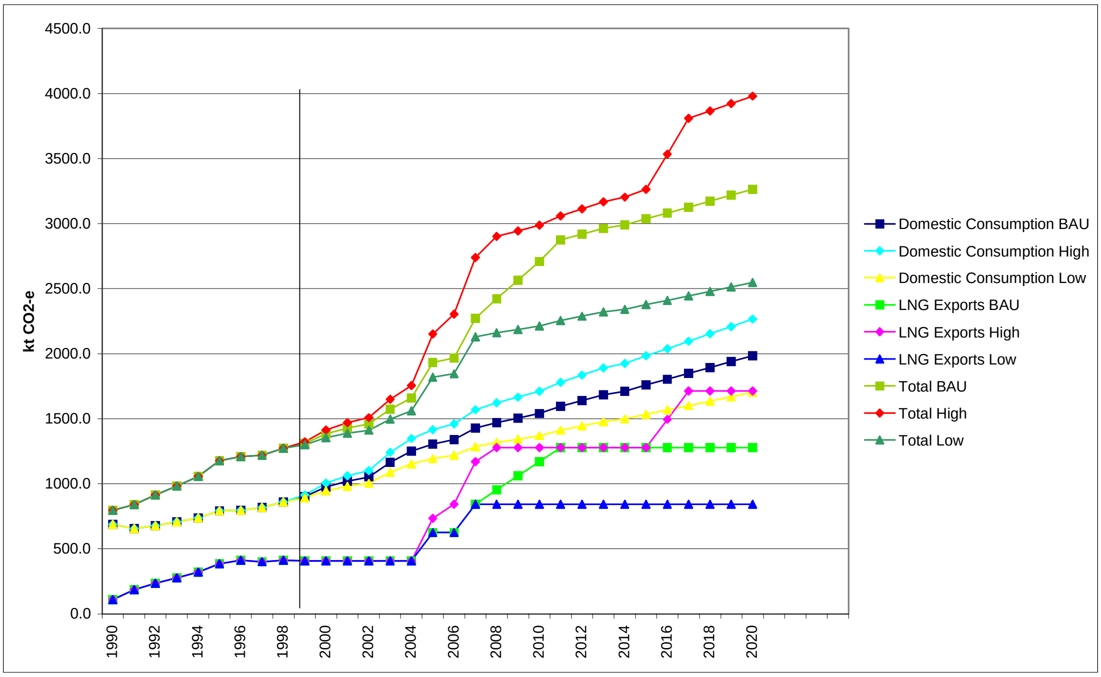
For methane vented in association with acid gas stripping, the same assumptions are used as in the Middle case.

For other sources of vented methane, the ratio of methane emitted to gas produced is 0.065 kt/PJ in 1998 and falls by 0.8% per year in each subsequent year.

Scenario results

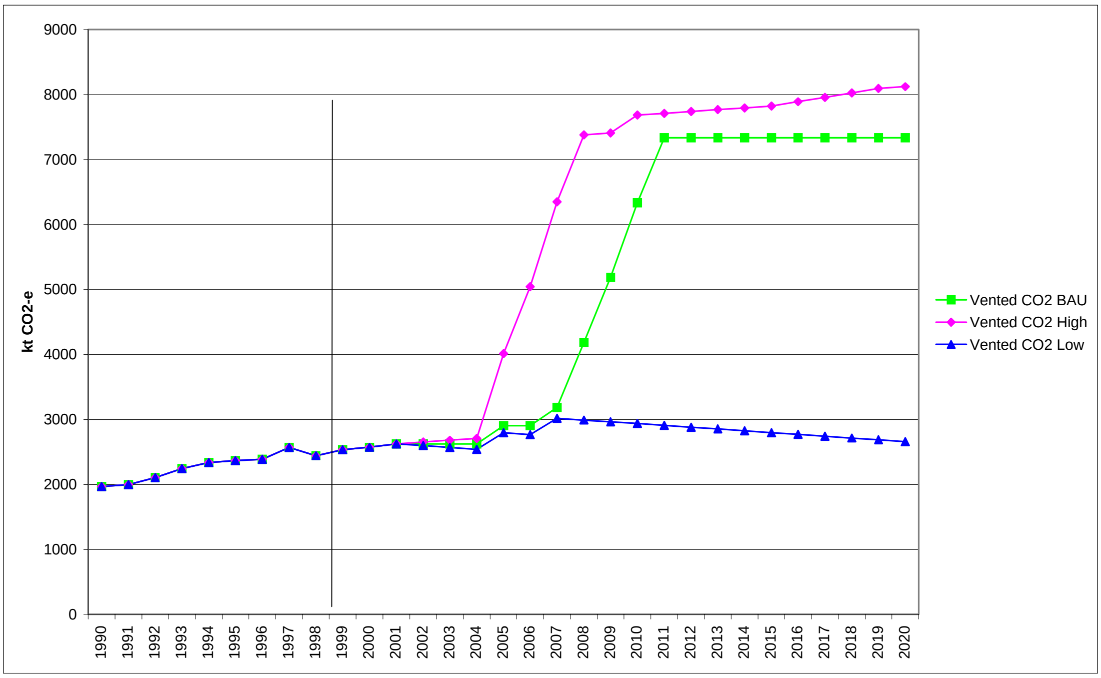
The three natural gas production and consumption scenarios described above are shown in Figure 12. Domestic consumption and LNG exports are shown separately.

Figure 12: Actual and projected production, domestic consumption, exports and total production of natural gas, 1990-2020



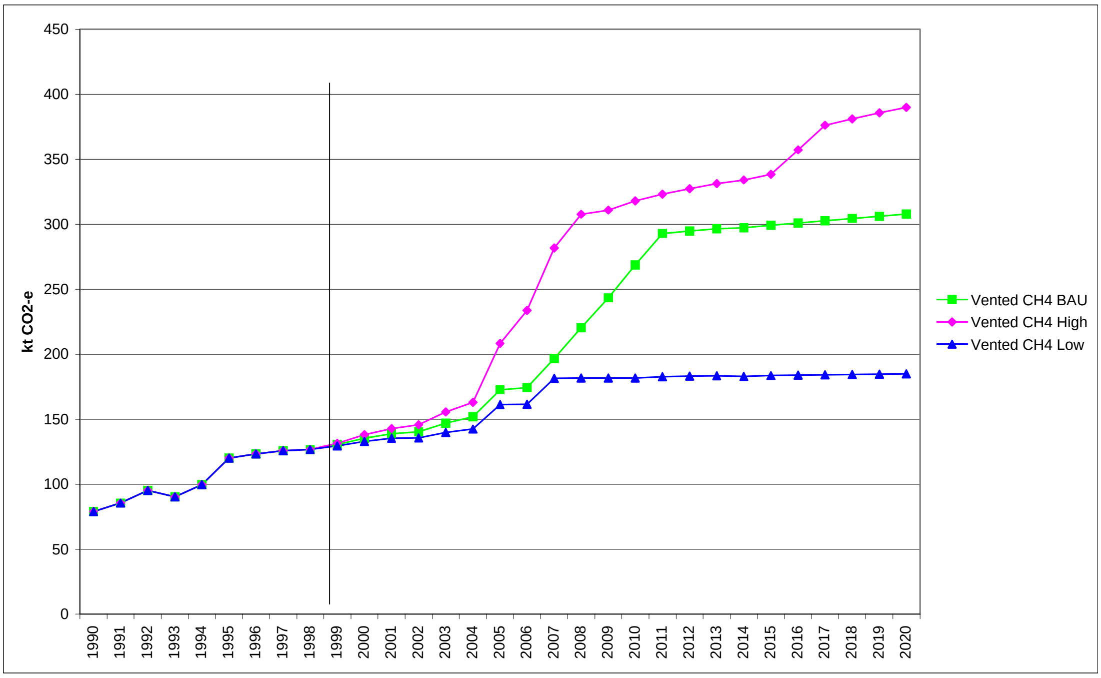
Total vented CO_2 emissions are calculated as the sum of emissions from all the fields and projects discussed. The three projections are shown in Figure 13.

Figure 13: Actual and projected emissions of vented CO_2, 1990-2020



Total vented methane emissions are calculated as the sum of emissions from the two source categories discussed above. The three projections are shown in Figure 14.

Figure 14: Actual and projected emissions of vented methane, 1990-2020



It is not possible to attach probability distributions to these projections, for the following reasons.

- The largest source of uncertainty is whether particular projects will, or will not, be developed. Major investment decisions of this kind are determined in part by objective factors, such as product prices, some of which can be known a few years ahead, though not with great certainty. However, investment decisions are also affected by a host of quite unknown and unpredictable factors, relating to corporate strategies and the like.
- As explained, there is virtually no information available in the public domain relating to other important factors, such as field by field CO_2 concentrations in Cooper/Eromanga Basin gas fields.

3.2.7 Options for emission reduction

The principle option for reducing venting emissions is reinjection of CO_2 into suitable underground geological formations, which may include the producing reservoirs themselves, adjacent depleted reservoirs, or other, non-hydrocarbon bearing formations. Under some circumstances, CO_2 reinjection may be used as a technique for maintaining reservoir pressure and hence production rates of oil, in which case it would be undertaken for straightforward commercial reasons..

In the great majority of cases, however, there is no commercial rationale for reinjecting CO_2. There are substantial fixed costs associated with reinjection, which means that it affords economies of scale. Thus for any given development, reinjection of CO2 would be an essentially all or none activity: if it is undertaken, then virtually all stripped CO2 would be reinjected. This means that, in terms of the emissions projection scenarios developed in this Section, reinjection of CO2 for any project would be equivalent to the project not proceeding.

Reinjection of CO_2 is a relatively costly process. We have been advised that overseas experience suggests that the cost may lie between A$15 and A$30 per tonne of CO_2, assuming that CO_2 has to be stripped for LNG operations, i.e. excluding the cost of stripping itself (P. Cook, Australian Petroleum CRC, *pers. comm.*). A recent Dutch study of the cost of sequestering CO_2 in depleted gas fields estimates a cost of NLG20-22 per tonne of CO_2 for injection and storage in offshore fields, equivalent to around A$15-16 per tonne (Netherlands Institute for Applied Geoscience TNO, 1999).

None of the three scenarios we have developed assume that reinjection would be undertaken. Governments could, if they wish, mandate the reinjection of CO2 for any petroleum development, but would need to consider whether this was the most cost effective way to reduce national GHG emissions. We return to this point in Chapter 4.

3.3 Flaring from oil and gas production facilities

Broadly speaking, flaring at oil and gas production facilities is associated with two different types of activity.

- At every production and processing facility small quantities of volatile hydrocarbons arise as waste streams from various activities; flaring is the standard safe way of disposing of these waste hydrocarbon streams.
- Some oil fields with associated gas are developed for oil production only. If it is decided not to reinject the associated gas (for cost or other reasons) and if economically feasible opportunities to develop the gas resource are not available (because the gas resource is too small or too remotely located), then the gas is flared. Around the world, flaring under such circumstances is a major source of fugitive emissions, e.g. from oilfields in Nigeria and some Persian Gulf countries. In Australia it occurs at some small offshore oil fields in WA.

Flaring gives rise mainly to emissions of CO_2. Small quantities of methane are also emitted as a result of incomplete combustion.

No data are available to allow flaring from these two source categories to be separately identified. It is therefore very difficult to postulate any plausible relationship between production of either oil or gas and the level of flaring emissions. While it might be supposed that emissions in the first category could be related, in approximate terms, to the levels of either gas, or gas plus oil, production, that is certainly not the case with the second category of emissions, which come from a small number of individual fields. It is entirely possible that many of the oil fields which could be sources of flaring in the later part of the study period have not yet even been discovered.

It is relevant that the WA Government is strongly encouraging oil producing companies not to flare associated gas, but to reinject instead. In general terms, the industry is committed to reduce fugitive emissions by reducing the quantity of hydrocarbons flared. Nevertheless, there may be future oil developments which involve flaring. It is also important to note that ABARE projections show Australian crude oil production staying roughly constant over the study period.

We have used the following assumptions in constructing the three cases for CO_2 emissions.

- For the Middle case, CO_2 emissions from flaring fall by 2% per year from the 1997 level.
- For the High case, CO_2 emissions from flaring fall by 1.5% per year from the 1997 level.
- For the Low case, CO_2 emissions from flaring fall by 2.5% per year from the 1997 level.

For the reasons explained above, these assumptions are essentially arbitrary. They assume a policy environment of general awareness about greenhouse gas emissions, but no specific policy measures, such as a requirement to reinject associated gas.

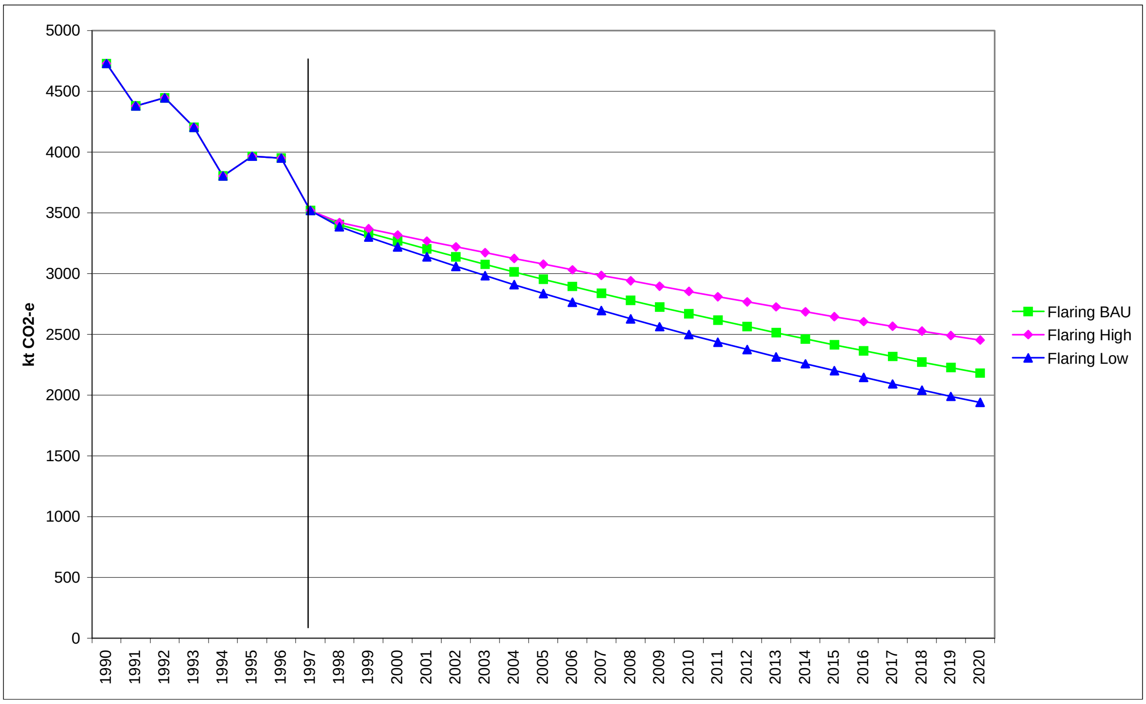
Emissions of methane are related to those of CO_2 by the ratio of their respective emission factors. The ratio of 0.0127 t CH_4 per tonne of CO_2 is the figure used in compiling the NGGI (National Greenhouse Gas Inventory Committee, 1996) and has been used for these projections. This means that CO_2 accounts for 79% of total emissions on a CO_2-e basis.

Total emissions from flaring at oil and gas production and processing facilities are shown in Figure 15 on a CO_2-e basis.

Reinjection of unwanted methane into suitable reservoir formations is the most effective way of reducing flaring emissions. Methane reinjection is often undertaken for commercial reasons. In many oil and gas fields, where the field production rates of oil and gas yields volumes of gas in excess of available market demand, methane is reinjected as a means of storing it for later re-extraction and sale. Methane reinjection is also used as a means of maintaining reservoir pressure and oil production rates.

If there is no commercial justification for reinjection, governments could, as in the case, make reinjection mandatory for oil field developers who were otherwise planning to flare. The policy issues are explored further in Chapter 4.

Figure 15: Actual and projected total emissions from flaring at oil and gas production and processing facilities, 1991-2020



Reinjection for later extraction is often undertaken as a means of storing gas for later extraction, in developments where the rate of production is set by the demand for liquid hydrocarbons.

3.4 Crude oil refining and storage

Flaring at oil refineries is a source of CO_2 and methane. The reasons for flaring are essentially the same as at oil and gas production and processing facilities, viz. safe disposal of hydrocarbon waste streams. Oil refineries are also a significant source of volatile hydrocarbon emissions (NMVOCs). However, since these are not direct greenhouse gases, they are not included in this study.

Emissions from flaring have decreased in the last few years, as oil refineries have invested to improve the efficiency of their operations and reduce greenhouse gas emissions. Aside from the effect of such improvements in technology, quantities flared are, in broad terms, related to the volume of crude oil processed.

The recent release of the Action Agenda report for the downstream petroleum industry (Department of Industry, Science and Resources, 1999) has clarified the likely future of Australian oil refineries. It is most unlikely that there will be any major new investment to increase processing capacity; new investment will be directed towards the production of higher grade products, such as low sulfur diesel. Indeed, the report confirms speculation, current for some time, that two of Australia's eight major refineries may be closed over the next two years. The candidates for closure are Port Stanvac, in SA, and Clyde, in NSW. If they are closed, products which they currently supply would for the most part be supplied by imports from refineries in Singapore and elsewhere in Asia, i.e. there would be little change in the total capacity of the remaining six refineries. These two refineries account for approximately 20% of current Australian refinery capacity.

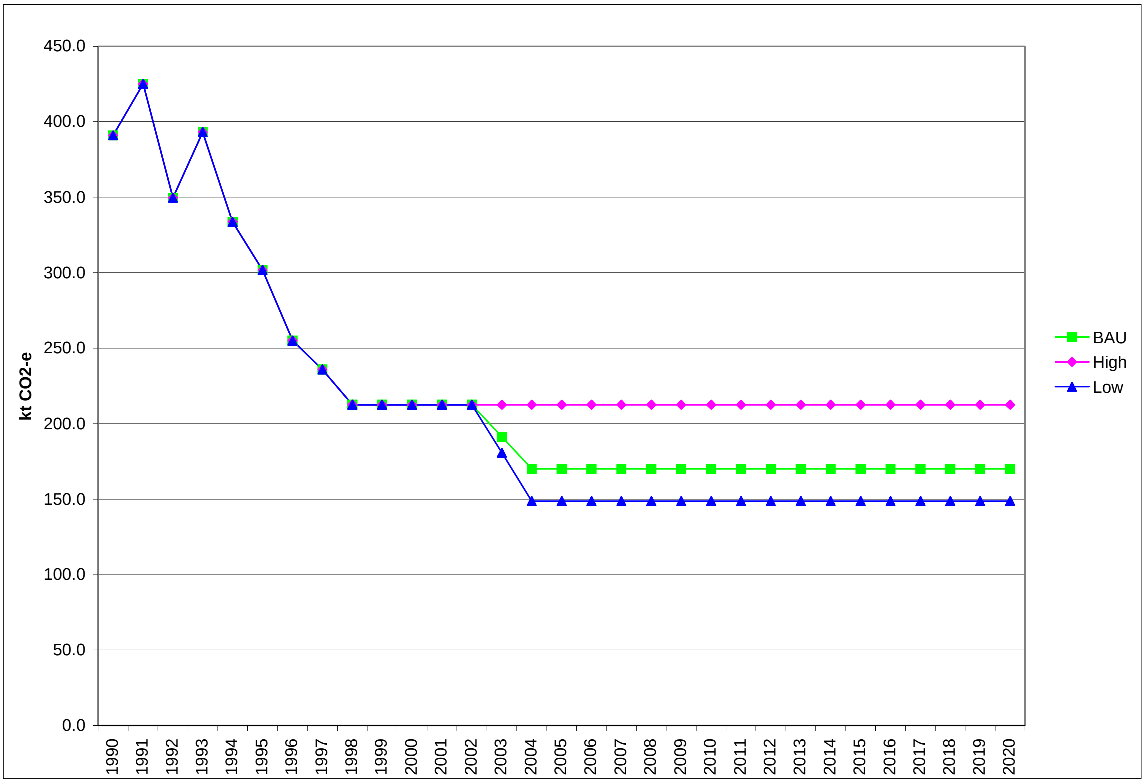
The following assumptions have therefore been used in constructing the three cases:

- Emissions of CO_2 fall from 222 kt in 1997 to 200 kt in 1998, reflecting further efficiency gains, and then remain at that level up to 2002 under all three cases;
- In the Middle case, emissions then fall to 160 kt by 2004, implying closure of Port Stanvac and Clyde, with no change to operations at the remaining refineries;
- In the High case emissions stay at 200 kt for the whole study period;
- In the Low case emissions fall to 140 kt by 2004, implying both closures and some further efficiency improvements at the remaining refineries.

Emissions of methane are related to those of CO_2 by the ratio of their respective emission factors. The ratio of 0.0025 t CH_4 per tonne of CO_2 is the figure used in compiling the NGGI (National Greenhouse Gas Inventory Committee, 1996) and has been used for these projections. This means that CO_2 accounts for 95% of total emissions on a CO_2-e basis. Note that this is significantly lower than the ratio for flaring at gas processing facilities, because in the latter case methane is the main hydrocarbon flared, whereas at refineries higher hydrocarbons account for most of the flare stream, and emissions of unburnt methane are consequently lower.

Emissions of CO_2 from flaring at oil refineries are shown in Figure 16.

Figure 16: Actual and projected total emissions from flaring at oil refineries, 1990-2020



3.5 Gas distribution

3.5.1 Estimating methane emissions

Most of the gas lost from gas distribution systems is by way of leakage from the low pressure network. The amount of leakage depends on the number and condition of joints in the pipes, and the operating pressures. Leakage from the high pressure and trunk mains is negligible. The pipes are welded steel, so flanged joints are typically only at valves and compressors. Pressures are so high that any leaks that might occur are obvious, dangerous and quickly attended.

According to Hutchinson et al (1993), other causes of fugitive emissions from gas distribution systems (up to and including the customer meter) are:

- third party damage (eg excavators);
- purging of new mains;
- unburnt gas from gas compressors (if there are any on the distribution system);
- gas lost to atmosphere on start up and shut down of compressors;
- regulating and relief valves.

There may also be fugitive emissions on the customer's side of the meter:

- leaking lines at fittings;
- purging of lines during appliance installation and maintenance;

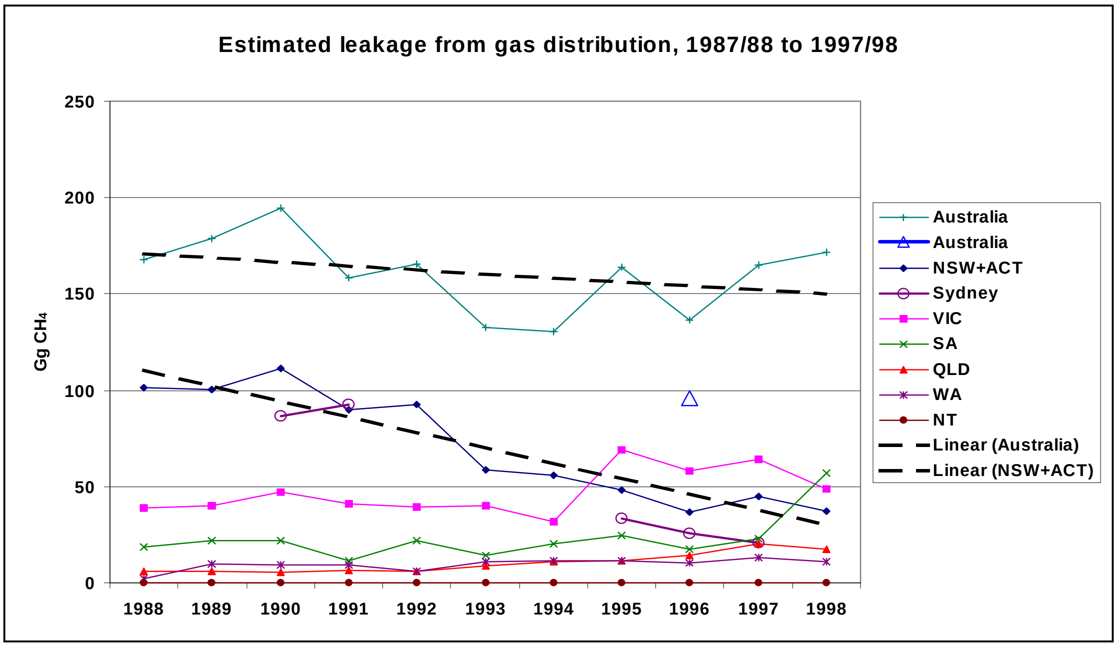
- leaking appliance valves;
- leakage when intermittently operated appliances (eg cookers) are ignited and extinguished.

There are no Australian data on emissions from the customer side of the meter. Emissions from the distributor side of the meter are not measured directly, but must be based on estimates of unaccounted for gas (UAG). While emissions account for the majority of UAG in Australia (Hutchinson et al, 1993), other elements include: meter inaccuracies; use of gas within the system itself; theft of gas; variations in temperature and pressure; and differences between billing cycles and accounting procedures between companies delivering and receiving the gas.

The methodology in Workbook 2.1 (National Greenhouse Gas Inventory Committee, 1997) assumes leakage from utility distribution systems in each year is equal to 90% of the amount of UAG that can be calculated from the data for published for each utility in the Australian Gas Association (AGA) annual *Gas Statistics Australia*. The 0.9 ratio of leakage to UAG is somewhat higher than estimates from industry studies: 80% (Dixon, 1990) and 70-80% (Hutchinson et al, 1993). The higher ratio adopted in Workbook 2.1 (National Greenhouse Gas Inventory Committee, 1997) was intended to make some allowance for the additional emissions from the customers' side of the meter, which were not covered in the two studies. The methodology takes into account the composition of each utility's pipeline gas, which varies slightly from year to year. While small quantities of CO_2 and NMVOCs are also vented, methane accounts for over 99.7% of the greenhouse impact of natural gas leakage from the distribution system. The 1997 NGGI reports 165.2 Gg CH_4 and 9.4 kt CO_2, making a total of about 3.5 Mt CO_2-e.

Figure 17 illustrates the trend in leakage from 1988 to 1998, calculated using the NGGI methodology. It also plots leakage estimates published from time to time by individual utilities and the AGA.

Figure 17 Estimated leakage from gas distribution by State, 1988 - 1998



In 1996 the AGA published an estimate of national distribution leakage based on information provided by AGA member companies which supply 97% of all gas issued by distributors in Australia. The AGA (1996) estimate was 99.1 kt CH_4, compared with 136.5 kt CH_4 estimated for 1996 using the NGGI methodology. This would imply that leakage was 65% of UAG in that year, rather than 90% as assumed in the NGGI.

However, single year estimates should be treated with caution, since the non-leakage components of UAG can change considerably from year to year. A change to a new computer billing system, for example, can shift UAG from one financial year to another. Trends are more reliable: if a future AGA survey also returns a lower leakage estimate, then the NGGI methodology should by adjusted – keeping in mind that some allowance should still be made for losses on the customer side of the meter. However, it may be more appropriate to base the latter element on either a percentage of consumption by residential and commercial customers, or on the number of customers or appliances.

Figure 17 illustrates the trends for the distribution systems in each State. The marked reduction in NSW + ACT leakage is due largely to the "Goldline" project: the relining with nylon pipe of the entire Sydney low-pressure distribution system, some of which is now over 150 years old. The Australian Gas Light Company (AGL) has from time to time published leakage estimates for Sydney and for NSW as a whole in its *Greenhouse Challenge* reports. These points are plotted on Figure 17. The AGL trend corresponds reasonably well with the value estimated in the NGGI. The Sydney relining project was completed in the mid 1990s. Another old system in Newcastle is also being relined, but after that no further gains are expected. AGL Canberra has a relatively new system laid in nylon from the start, so leakage is already minimal.

The trends for the other States are more difficult to relate to known physical changes. There have been no large scale rehabilitation projects comparable to "Goldline" in other States. The marked increase for Victoria between 1994 and 1995 is due to a change in UAG data collection methodology, which introduced a discontinuity in the series. There was an unexplained jump in South Australian UAG in 1998, which is likely to have been due to accounting or meter-reading factors rather than physical changes, but this will not be known until new data become available for subsequent years.

Given the variability of UAG from year to year, it may be advisable to revise the NGGI methodology to report distribution system leakage as a 3 year moving average (see difference between Figure 18 and Figure 19).

3.5.2 Projections of methane emissions

Distribution system leakage is largely independent of throughput, so projections of gas consumption are not a useful indicator of likely rends in leakage.

Figure 17 shows that now that the NSW system has been rehabilitated, the Victorian distribution system is the largest single contributor to national fugitive emissions (assuming that the 1998 value for SA is an aberration).

It is not likely that a comprehensive project such as “Goldline” would be economic in Victoria. The revenue impact of losses on Victorian gas utilities is far lower than on AGL. It is estimated that prior to Goldline, AGL was losing over 8% of the gas it purchased from its suppliers, and after Goldline it is down to about 2%. For Victoria, it is already 2% (although the absolute losses are now higher than in NSW, sales are also higher, so the ratio of leakage to sales is similar). Furthermore, the wholesale price for natural gas paid by the distributors to the producers has historically been much lower in Victoria than in NSW, further undermining the economic incentive for rehabilitation. Wholesale gas prices are likely to rise in the future, but whether this would be sufficient to increase rehabilitation activity in the States with the older distribution systems (Victoria and SA) remains to be seen.

Given that there appears to be no further imperative for large scale rehabilitation, the Business as Usual projection assumes a gradual increase in leakage as the distribution systems age. (It is also assumed that SA returns to the longer term trend line after 1998). The projection is illustrated in Figure 18 (unsmoothed) and 19 (smoothed).

The NGGI estimate for fugitive emissions from gas distribution was 165.2 kt CH_4 (3.47 Mt CO_2-e). It is projected that this will rise by about 5% to about 174 kt CH_4 (3.65 Mt CO_2-e) by 2020 in the BAU case.

Figure 18 Historical and projected gas distribution leakage, 1990 – 2020

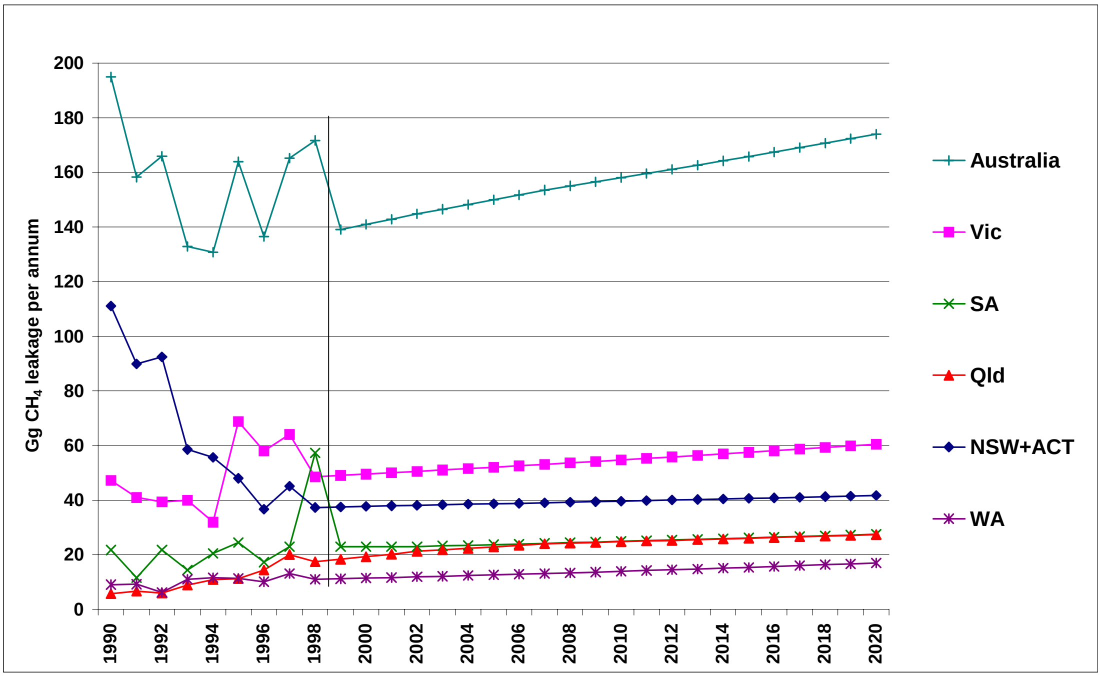


Figure 19 Historical and projected gas distribution leakage, 1990 – 2020 (Smoothed – 3 year moving average)

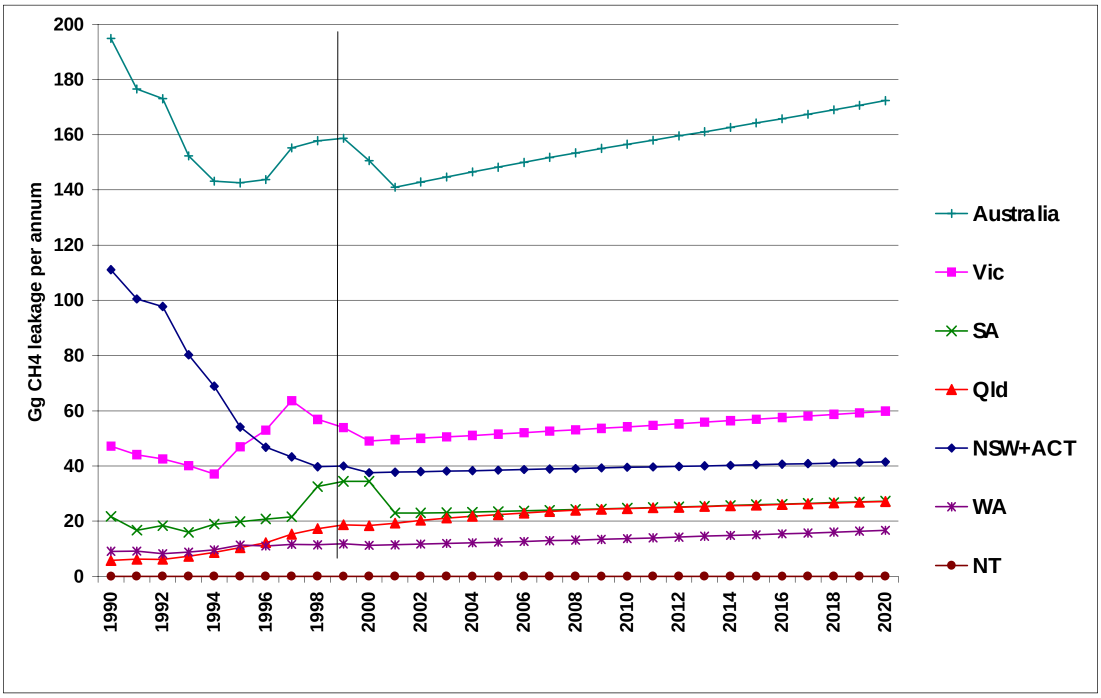


Figure 20 Historical and projected gas distribution leakage, as a percentage of gas consumption 1990 – 2020 (leakage smoothed – 3 year moving average)

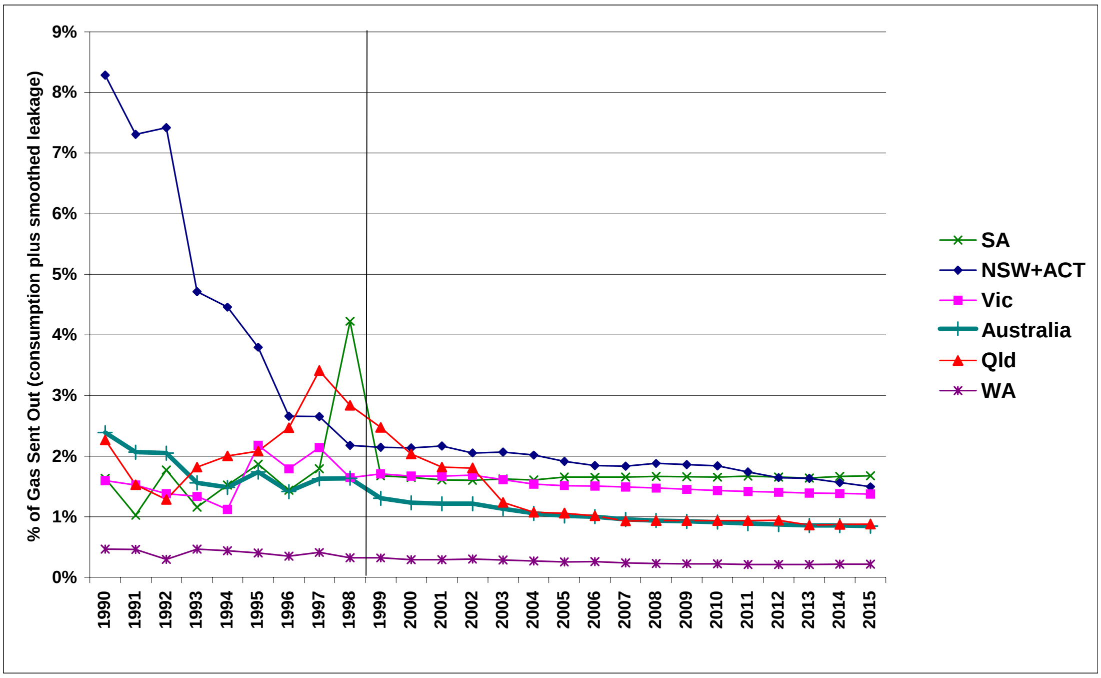


Figure 20 expresses leakage as a percentage of the gas sent out into the distribution networks. ABARE (1999) projects natural gas consumption in Australia to double, from 639 PJ in 1997 to 1248 PJ by 2015. Therefore, if gas leakage increased by 5% the leaked share of gas sent out would decline from more than 2% in 1990 to well below 1% in 2015. Note that leakage as a percentage of gas sent out is calculated *after* leakage is estimated: there is no necessary relationship between gas issues and leakage rates.

Figure 21 illustrates three scenarios for methane leakage from natural gas distribution (expressed as Mt CO_2-e). The High scenario has been set arbitrarily at 15% above the BAU scenario. The Low scenario set at 70% of the BAU value, in effect represents the uncertainty associated with the methodology: if future surveys were to return similar leakage estimates in the AGA’s 1996 survey, and the NGGI methodology were revised accordingly. The range between the High and Low scenarios in 2020 is about 1.7 Mt CO_2-e. Even under the High scenario emissions in 2020 would be little higher than in 1990, because of the large reduction in leakage in the early 1990s due to the “Goldline” rehabilitation project.

Figure 21 Projected emissions from natural gas distribution, 1990-2020

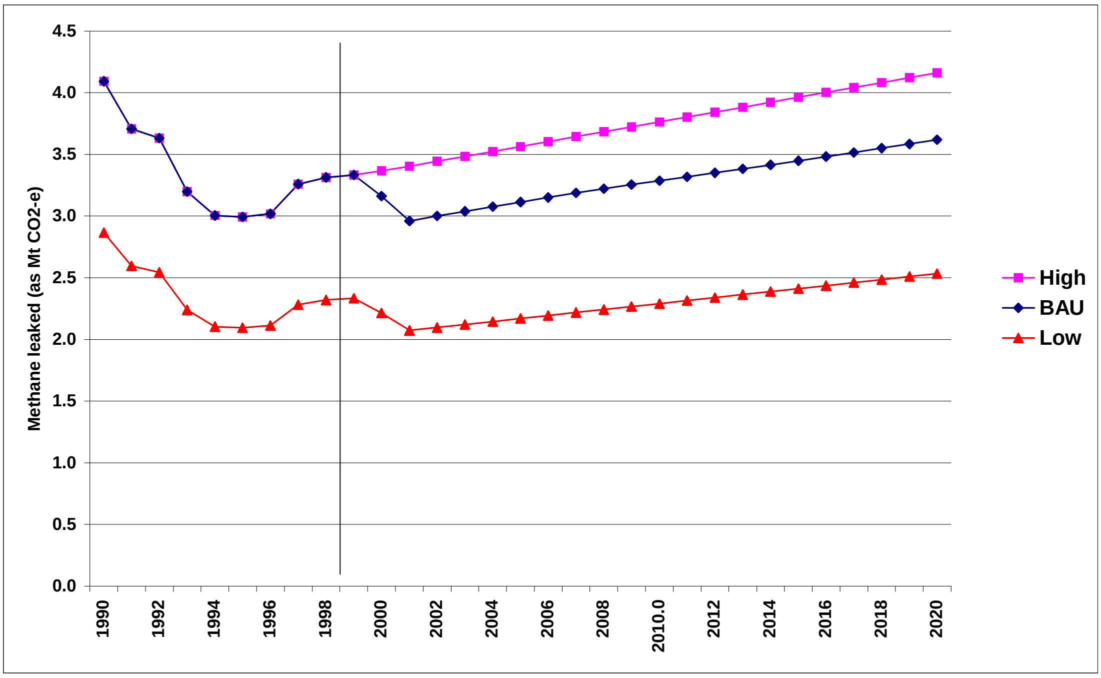


Table 10 Summary of projection scenarios

Scenarios	1990 Mt CO_2-e	2010 Mt CO_2-e	2020 Mt CO_2-e	Change, 1990-2020	
				Mt CO_2-e	%
Highest	4.1	3.8	4.2	0.1	2%
BAU	4.1	3.3	3.6	-0.5	-11%
Lowest (a)	2.9	2.3	2.5	-0.3	-12%
Highest cf Midpoint	0	0.5 (+14%)	0.6 (+15%)		
Lowest cf Midpoint	0	-1.0 (-30%)	- 1.1 (-30%)		
Maximum range	0	1.5	1.7		

(a) This involves a change in methodology, which would also have to applied retrospectively

3.5.3 Carbon dioxide emissions "at the burner tip"

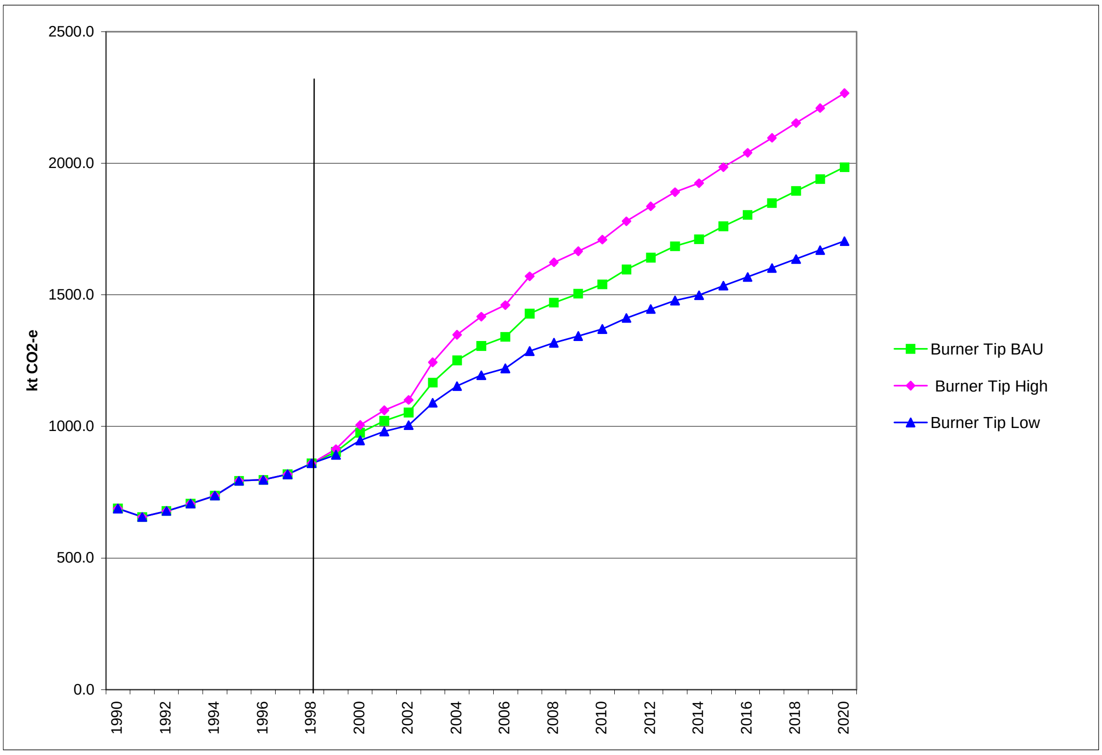
Raw natural gas, typically contains CO_2, in addition to methane and other hydrocarbons. Complete removal of CO_2 is a costly and relatively energy intensive process, and it is technically acceptable for pipeline gas to contain small concentrations of CO_2. For Australia as a whole, the concentration of CO_2 in pipeline gas has averaged about 1.0% on a molecular (or volume) basis over the past decade or so, being slightly higher in some pipeline systems, and slightly lower in others. This CO_2 is emitted at the burner when the gas is burnt. Up to now it has not been accounted in the NGGI, but this omission will be remedied in the 1998 NGGI.

In 1997 the national average concentration was 1.0 Gg/PJ, as it had been for most of the 1990s. Total emissions in 1997 were therefore 819 Gg.

Emissions have been projected by assuming that the concentration will remain at 1.0% by volume. Emissions will therefore be directly proportional to the quantity of natural gas consumed in the domestic economy, including gas used at gas processing plants.

The three domestic gas demand scenarios used to project venting emissions have been used to project emissions from this source, i.e. for the Middle case, the ABARE projections of Australian consumption of natural gas, and for the High and Low cases demand growth from 1997 approximately 25% higher and 25% lower respectively. Projected emissions are shown in Figure 22.

Figure 22: Actual and projected emissions of fugitive CO_2 from gas consumption, 1990 to 2020.



3.6 Other sources of fugitive emissions

3.6.1 Exploration

Emissions from petroleum exploration activities are associated with the flaring of natural gas released in the course of production testing of successful wells. While emissions will tend to be higher with higher levels of exploration activity, there is of course no simple relationship between exploration activity and emissions, since the latter will depend on the outcomes of exploration activity.

Emissions were 10 kt of CO_2 in 1997. We have assumed emissions of 10 kt in each year from 1998 to 2020 under all three cases.

3.6.2 Crude oil production

Small quantities of methane are emitted during the loading of crude oil at production facilities. These emissions have averaged around 0.5 kt p.a. since 1991 and were 0.4 kt in 1997. We have assumed emissions of 0.4 kt in each year from 1998 to 2020 under all three cases.

3.6.3 Crude oil transport

Further small quantities of methane are emitted during the seaborne transport of crude oil. These emissions are, in broad terms, proportional to the volume of crude oil being transported. They have been about 0.3 kt p.a. in recent years and, having regard to the expected roughly constant level of domestic crude oil production over the study period, we have assumed this constant level throughout the study period in all three cases.

3.6.4 Natural gas production and processing (other than venting and flaring)

Relatively small quantities of methane are emitted as a result of miscellaneous leaks in pipe systems at gas production and processing facilities. During recent years these emissions have ranged from 1.3 to 2.1 kt and averaged about 0.0017 kt per PJ of natural gas produced. We have assumed a ratio of 0.0016 kt/PJ produced for the purpose of projection, and used the three production cases defined in Section 3.2 above. This results in emissions from this source roughly doubling under the Low case and trebling under the High case.

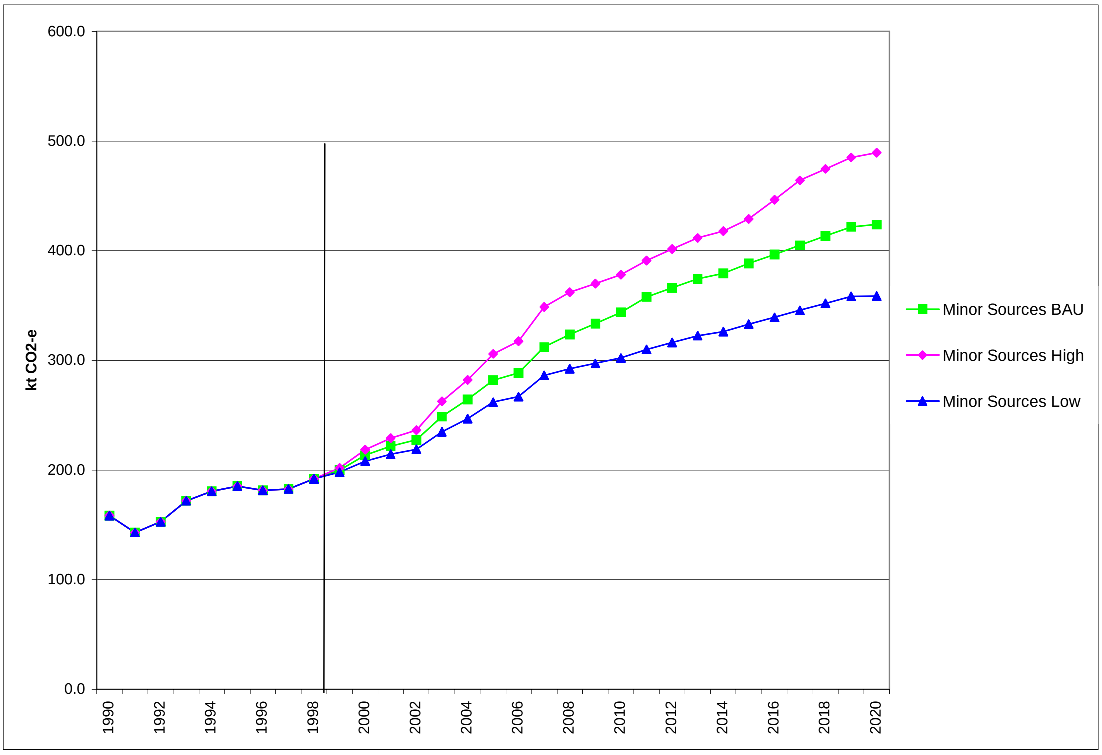
3.6.5 Natural gas transmission

Small quantities of methane escape from gas transmission pipelines, mainly as a result of blowdowns and other maintenance activities at compressor stations. In broad terms, the quantity released is proportional to the throughput of the pipeline system. A factor of 0.007 kt/PJ of gas transported was used for the NGGI in 1997, and this ratio has been used for projections. The three cases are defined by the three scenarios of domestic gas consumption, which are defined in Section 3.2. This sees emissions from this source rise from just under 6 kt in 1997 to nearly 15 kt in 2020 under the BAU case.

3.6.6 Overview of emissions from minor sources

Projected emissions from the minor sources discussed in this Section are shown in Figure 23 in CO_2-e terms. As will be seen from the discussion, methane accounts for the overwhelming proportion of these emissions.

Figure 23: Actual and projected emissions of fugitive CO_2 and methane from minor oil and gas related sources, 1990 to 2020



3.7 Overview of petroleum (oil and gas) emissions

Figure 23 shows emissions from each of the five main categories or sources of emissions discussed in the preceding Sections, expressed in CO_2-e units, under the Middle case assumptions. It can be seen that at present venting is the largest source, with flaring and gas distribution leakage also major sources. However, over the projection period, venting comes to dominate emissions.

The dominance of venting, which is mainly a source of CO_2, can also be seen in Figure 24, which shows emissions of the two gases separately. Although CO_2 and methane contribute roughly equal shares of total emissions over most of the period, this is not the case over the period 2007-10, where CO_2 grows more rapidly. Both the dominance of venting and the rapid growth in total emissions over that period arise mainly from the assumptions made in the Middle scenario about the Gorgon LNG project. Under the assumptions used, venting emissions from this project will account for 24% of total petroleum emissions, and 34% of CO_2 emissions from petroleum related activities, in 2011, the year in which the project is assumed to reach full production. If the assumed North West Shelf expansion is also included, the share of total emissions attributable to venting from the two new projects rises to 28%.

This effect can also be seen in Figure 25, which shows total petroleum sector emissions under the three scenario assumptions. Under the Low case, it is assumed that Gorgon does not proceed within the time frame of this study; consequently emissions are much lower than in either of the other two cases.

It is important to emphasise that the projection scenarios have been prepared by assuming no new policy initiatives relating to GHG emissions. We discuss policy issues in the next Chapter. The projections are summarised in Table 11.

Table 11 Summary of petroleum projection scenarios

Scenarios	**1990 Mt CO_2-e**	**2010 Mt CO_2-e**	**2020 Mt CO_2-e**	**Change, 1990-2020**	
				Mt CO_2-e	**%**
Highest	13.7	23.3	25.9	12.2	89%
Midpoint	13.7	20.0	22.2	8.5	62%
Lowest [(a)]	12.5	13.4	13.2	0.7	6%
Highest cf Midpoint	0	3.3 (+17%)	3.7 (+17%)		
Lowest cf Midpoint	-1.2	-6.6 (-33%)	-8.0 (-36%)		
Maximum range	1.2	9.9	11.7		

(a) This involves a change in methodology relating to gas distribution, which would also have to be applied retrospectively

Figure 24: Actual and projected combined emissions of CO_2 and methane from each petroleum related sources, by source, 1990-2020

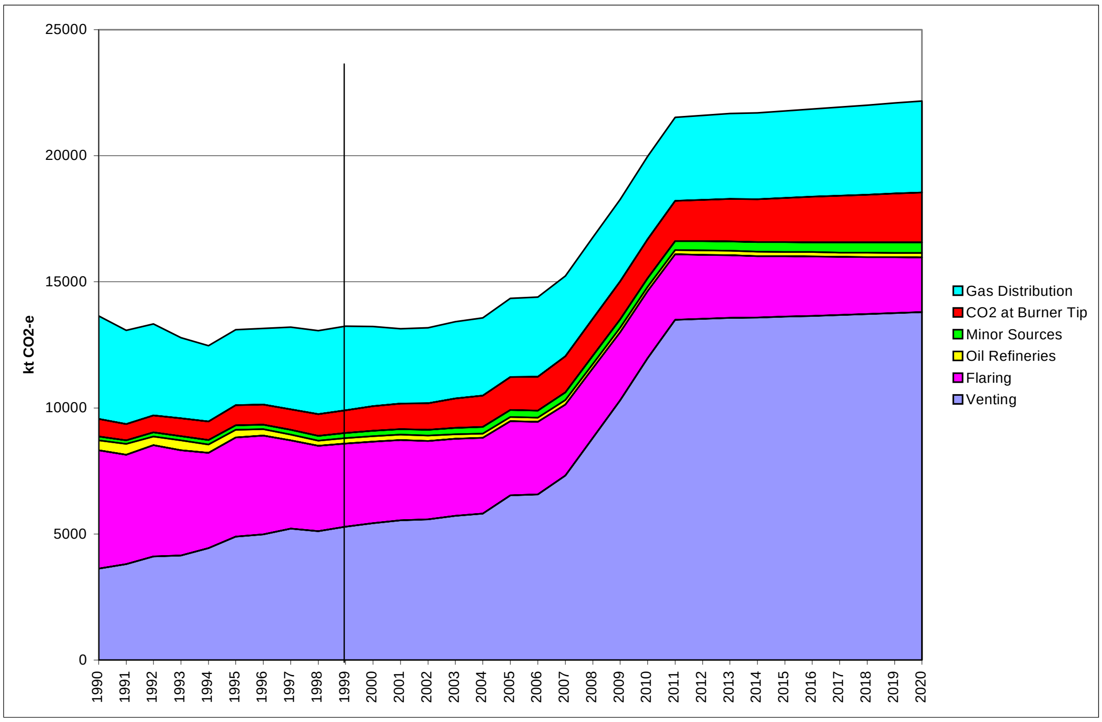


Figure 25: Actual and projected emissions of CO_2 and methane from petroleum related sources, by greenhouse gas, 1990-2020

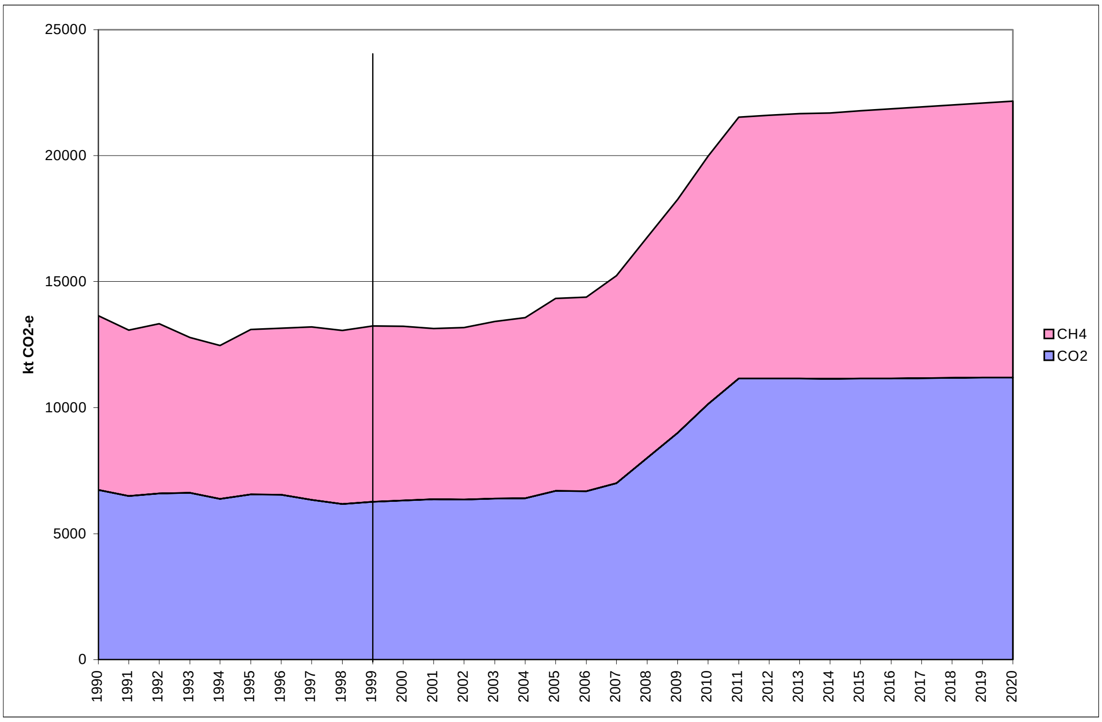
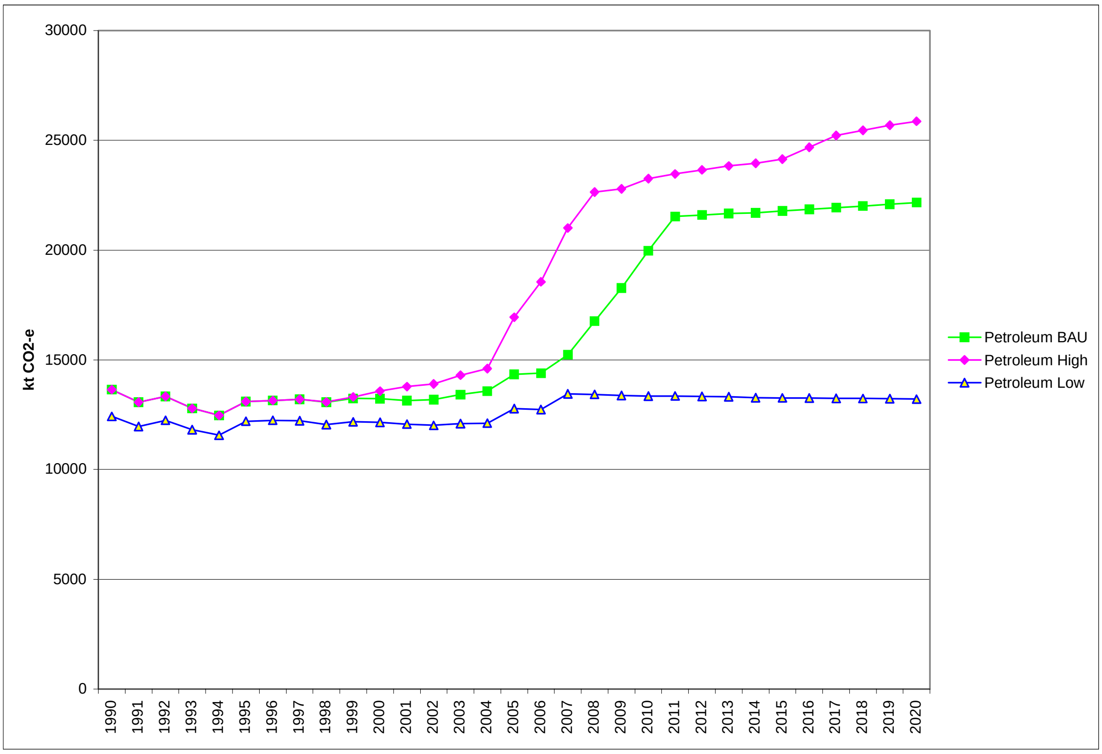


Figure 26: Actual and projected combined emissions of CO_2 and methane from petroleum related sources under the three scenarios, 1990-2020



4. FUGITIVE EMISSION SCENARIOS

4.1 Relationship to greenhouse policy options

The two largest sources of fugitive emissions are WCMG and oil and gas production. These sectors are likely to be influenced by the greenhouse policy environment, but in significantly different ways.

4.1.1 Waste Coal Mine Gas

For WCMG, past and present greenhouse policy settings are built into the BAU case. The current level of WCMG generation, including the increase projected to result from recent developments, was partly influenced by the value placed on gaining experience with the technology and in demonstrating corporate responsiveness to the greenhouse issue. However, it is likely that mine safety considerations, and the expected value of the electricity generated (which in the event have proved incorrect) had a greater influence.

Whether the “medium generation” or the “maximum generation” scenarios are realised will depend largely on future greenhouse policy settings.

The “medium” estimate of new WCMG generation may correspond to a scenario in which electricity prices are relatively low, there is a moderate level of incentive for reducing GHG emissions, and mitigation (i.e. flaring) options take precedence over utilisation. The “maximum” estimate presupposes higher electricity prices and/or more vigorous greenhouse policies, such as higher financial incentives for capture, emissions permits covering coal miners or regulated limits on discharges.

Energy Strategies et al (1999) concluded that:

> Inclusion of underground coal mines along with electricity generators within the initial scope of an emissions trading scheme would have a strong impact on WCMG development, possibly making other incentives unnecessary. Permits should be required for both fugitive methane emissions as well as combustion CO_2 emissions.
>
> A grant, subsidy or tax-based mitigation incentive scheme would increase the incentive for mine operators to invest in WCMG abatement, which in some cases would be generation and in other cases lower-cost mitigation only.

4.1.2 Oil and gas production

As already noted, the major direct policy option available to governments is to eliminate venting and/or flaring by making reinjection a condition of project development. In the Norwegian sector of the North Sea, the developers of the

Sleipner gas and condensate field were required to reinject The CO_2 content of the Sleipner field is 4.5 to 9.3 mole % of the raw gas, which is stripped to a content of 2.5 mole %. The CO_2 stripped from the well stream is being injected into a water-bearing structure in Utsira formation sands about 1000 m below the seabed. Since production commenced in 1996, over 1 Mt p.a.of CO_2 has been injected into to the reservoir (Sleipner Carbon Dioxide Storage Workshop, 25-26 November 1997, Trondheim, Norway).

As previously explained, mandating emission control by means of reinjection is an all or nothing policy. The effect of the policy on emissions can therefore be seen by simply eliminating the projected emissions for whichever fields are assumed to be affected. Of course, mandating reinjection may increase costs to the extent that the development was no longer a commercial proposition and therefore does no proceed. The effect on projected emissions would be identical. In other words, the two possible outcomes of such a policy would appear identical in terms of their effect on emissions, though not in many other respects.

4.2 Cost estimates

Energy Strategies et al. (1999) found that the costs of greenhouse mitigation through electricity generation using WCMG were sensitive to national electricity market pool prices. The cost estimate ranged from A$5 to 10 per tonne CO_2-e at a price of 1.2 c/kWh to A$ -2 to +2 at 4.8 c/kWh.[7]

For oil and gas production, cost estimates of between A$15 and A$30 per tonne of CO_2, assuming that CO_2 has to be stripped for LNG operations, have already been mentioned.

While these costs are high, they are lower than the estimated costs of reducing emissions through the use of renewable forms of energy, which the Government itself has effectively capped at about A$40/tonne.[8]

Other large scale reduction opportunities in the economy include increasing the operating efficiency of large scale power generation, the costs of which are estimated at + A$10 per tonne at 10% discount rate from the proposed efficiency standards for electricity generators (Efficiency Standards Working Group, 1999).

The average cost of proposed national energy efficiency programs for appliances and equipment use, such as minimum energy performance standards

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[7] A negative value for CO_2 reduction means that the operating or energy cost savings are greater than the cost of the measure, so the option is cost-effective in its own right.

[8] Press release on the 2% Renewables target by Senator Hill, 29 November 1999, stated that "Certainty for industry to plan for the measure has been provided by fixing the target at 9,500 gigawatt hours and capping penalties for liable parties who fail to meet their purchase obligation at $ 40 per megawatt hour". Assuming a general greenhouse-intensity of 1 tonne per MWh, this implies a reduction cost to liable parties of $ 40 per tonne. The regulatory penalty sets a market limit on the cost of renewables, since a liable party facing a price of greater than A$40/MWh will be better off paying the fine.

and enhanced and expanded energy labelling are estimated at about – A$ 30 per tonne CO_2-e (George Wilkenfeld and Associates, 1999)

These cost estimates are summarised in Table 11.

Table 11 Estimated costs of greenhouse gas reduction options

Options	**Estimated cost per tonne CO_2-e avoided**
Energy efficiency programs for appliances and equipment	-30
Electricity generation from waste coal mine gas	-2 to +10
Increasing efficiency of existing electricity generation	+10
Sequestering CO_2	+15 to +30
Electricity Generation from Renewables	Up to +40

How the costs impact on fugitive emissions outcomes will depend on many factors, such as how emission costs are internalised in investment decisions and the scope for lower cost mitigation options to be taken up first in the economy.

For example, by choosing to implement the 2% Renewables target the Government has in effect implemented a high-cost measure (though one with significant benefits over and above the direct benefit of emission reduction) in addition to lower-cost measures.

A similar approach could be applied to oil and gas producers, e.g. by incorporating a greenhouse trigger in development applications, and granting project approvals subject to the use of reinjection. This could significantly reduce the rate of growth in vented CO_2 emissions, either by making new projects unviable (if the additional cost cannot be recovered through the product sales) or ensuring that reinjection does take place where projects proceed.

Alternatively, oil and gas producers could be included within the scope of a national emissions trading scheme. In that case, they may be able to purchase permits from power generators (who face reduction costs of A$10 per tonne) at less cost than undertaking reinjection at A$15 to 30 per tonne. Under this scenario, fugitive emissions may rise at a higher rate than in other sectors, but still within an overall national constraint.

The major companies with interest in LNG projects are closely following developments in both emissions trading and the other Kyoto flexibility mechanisms (Clean Development Mechanism and Joint Implementation). Should they participate strongly in these activities, fugitive emissions would increase, as with emissions trading, but so too would national emissions, all else being equal.

Clearly, the responsiveness of the growth in fugitive emissions to greenhouse policy initiatives depends on the precise form of the initiatives, and the relative mitigation costs which they impose, or imply, for the fugitive and other sectors.

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APPENDIX: NUMERICAL VALUES USED IN TEXT FIGURES

Table A

Figure 1 data: Projected fugitive emissions under Business as Usual, by source sub-sector and gas, 1990 to 2020

		1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**
Kt CO_2	Coal	458.7	463.9	477.8	495.2	454.5	429.0	451.6	459.1	490.3	496.0	501.8
	Petroleum	6736.0	6493.7	6603.8	6621.9	6376.9	6559.5	6549.8	6340.2	6180.6	6262.4	6319.2
kt CH_4	Coal	16760.0	17002.2	17735.6	18005.2	17097.1	16823.9	17639.6	16974.5	18027.6	18101.9	17581.2
	Petroleum	6911.1	6579.0	6727.7	6159.7	6086.3	6539.8	6599.2	6863.8	6883.7	6973.8	6906.3

		2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
kt CO_2	Coal	507.7	513.7	520.6	527.5	534.6	541.8	549.1	556.4	563.8	571.4
	Petroleum	6365.3	6346.5	6391.9	6408.1	6696.4	6684.9	7007.6	8005.7	8996.2	10139.1
kt CH_4	Coal	17356.3	17137.5	16920.0	16708.1	16502.1	16838.3	17180.6	17487.3	17798.6	18114.5
	Petroleum	6769.9	6834.3	7021.6	7161.2	7639.0	7702.4	8224.4	8755.5	9270.8	9831.7

		2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
kt CO_2	Coal	579.0	586.8	594.5	602.3	610.2	618.2	626.3	634.6	642.9	651.4
	Petroleum	11153.4	11157.8	11161.1	11149.0	11159.0	11165.0	11173.5	11182.8	11192.8	11203.5
kt CH_4	Coal	18435.0	18760.4	19061.3	19366.1	19674.7	19987.2	20303.7	20624.2	20948.8	21277.4
	Petroleum	10374.1	10442.5	10508.2	10550.8	10623.9	10690.6	10759.8	10829.1	10898.5	10961.7

Figure 2 data: Contributions to total fugitive emissions of each greenhouse gas, 1990 to 2020

		1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
kt CO_2	Total	7194.7	6957.6	7081.6	7117.1	6831.4	6988.5	7001.3	6799.3	6670.9	6758.4	6821.1	6873.0	6860.2	6912.5	6935.6	7231.0	7226.7	7556.7	8562.1	9560.0	10710.4	11732.4	11744.6	11755.6	11751.3	11769.1	11783.2	11799.9	11817.4	11835.7	11854.9
kt CH_4	Total	23671.9	23581.1	24463.3	24164.9	23183.4	23363.7	24238.8	23838.3	24911.3	25075.7	24487.5	24126.2	23971.9	23941.6	23869.4	24141.0	24540.7	25405.0	26242.9	27069.4	27946.2	28809.1	29202.9	29569.5	29916.9	30298.7	30677.9	31063.5	31453.3	31847.3	32239.2

Table C

Figure 3 data: Projected total fugitive emissions under BAU, High and Low scenarios, 1990 to 2020

Coal and Petroleum kt CO_2-e	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**
BAU	30901.0	30571.8	31579.0	31314.9	30044.0	30382.7	31270.8	30659.2	31606.3	31857.8	31331.9
High	30787.97	30418.2	31410.3	31152.3	29914.1	30237.9	31179.6	30625.7	31802.0	32111.1	32572.6
Low	29560.2	29305.8	30320.5	30192.7	29012.4	29340.2	30274.1	29647.8	30773.4	30974.7	30052.2

	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
BAU	31022.1	30854.5	30875.9	30826.2	31392.9	31787.8	32981.8	34824.6	36648.8	38675.6
High	33143.2	33649.4	34492.7	35251.3	38069.5	40160.9	43105.6	45251.0	45914.6	46923.5
Low	29136.0	28257.2	27435.5	26560.8	26324.2	26462.5	27354.6	27489.6	27612.0	27739.9

	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
BAU	40560.1	40965.8	41343.1	41685.8	42085.1	42478.1	42880.1	43287.0	43699.0	44109.8
High	47681.3	48417.9	49148.0	49839.5	50611.1	51738.2	52884.0	53739.2	54608.4	55433.0
Low	27907.8	28059.0	28221.7	28358.2	28535.0	28706.2	28882.8	29062.0	29243.6	29421.3

Table D

Figure 4 data: Fugitive methane emissions related to coal production (kg methane per tonne of black coal produced)

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**
Underground Class A	18.28	18.47	18.57	19.02	18.74	18.36	17.20	17.15	17.20	17.2	17.2
Underground Class B	0.52	0.52	0.50	0.51	0.46	0.50	0.54	0.53	0.54	0.5	0.5
Open Cut	1.26	1.26	1.28	1.28	1.30	1.30	1.29	1.33	1.34	1.3	1.3
Post mining (Class A only)	0.7714	0.7714	0.7714	0.7720	0.7714	0.8219	0.7702	0.7715	0.77	0.771	0.771
Underground (weighted)	11.18	10.78	11.16	11.11	10.25	9.12	9.27	8.78	8.74	8.69	8.63
All coal (gross)	4.28	4.17	4.09	4.13	3.88	3.55	3.60	3.48	3.49	3.47	3.44
All coal (net)	4.08	3.95	3.86	3.83	3.64	3.37	3.45	3.08	3.12	3.06	2.97

	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Underground Class A	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2
Underground Class B	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Open Cut	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Post mining (Class A only)	0.771	0.771	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Underground (weighted)	8.58	8.52	8.48	8.44	8.40	8.36	8.32	8.29	8.26	8.23
All coal (gross)	3.41	3.39	3.37	3.35	3.34	3.32	3.30	3.29	3.28	3.28
All coal (net)	2.95	2.93	2.93	2.92	2.91	2.90	2.89	2.89	2.88	2.88

	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Underground Class A	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.20
Underground Class B	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.54
Open Cut	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.34
Post mining (Class A only)	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.77
Underground (weighted)	8.20	8.17	8.18	8.18	8.19	8.19	8.19	8.20	8.20	8.20
All coal (gross)	3.27	3.26	3.26	3.26	3.27	3.27	3.27	3.27	3.27	3.27
All coal (net)	2.88	2.88	2.88	2.89	2.89	2.90	2.90	2.91	2.91	2.92

Table E

Figure 5 data: Current production and capacity of mines and projects, by mining method

	1997	**1998**	**1999**	**Projects**
Underground	28.7%	29.0%	28.9%	28.6%
NSW Open Cut	27.4%	27.6%	27.9%	38.4%
QLD Open Cut	43.9%	43.4%	43.3%	33.1%
	100.0%	100.0%	100.0%	100.0%

Table F

Figure 6 data: Current production and capacity of mines and projects by region, underground mines

	1997	**1998**	**1999**	**Projects**
Southern U/G	20.9%	19.4%	17.0%	4.0%
Newcastle U/G	21.7%	20.5%	21.4%	11.8%
Hunter U/G	33.0%	34.2%	35.1%	35.6%
Bowen U/G	24.4%	25.9%	26.6%	48.6%
	100.0%	100.0%	100.0%	100.0%

Table G

Figure 7 data: Historical and projected rates of change in black coal production, 1990-2020

	1990-1998 (Historical)	**1998-2002**	**2002-2007**	**2007-2012**	**2012-2020**
Underground Class A	1.4%	1.1%	1.3%	1.3%	1.3%
Underground Class B	7.1%	2.5%	2.3%	2.1%	1.2%
Open Cut	4.6%	2.5%	2.2%	1.7%	1.2%
All NSW	4.6%	2.52%	2.32%	1.82%	1.49%
All Qld	4.5%	2.10%	1.97%	1.60%	0.95%
Total production	4.3%	2.29%	2.13%	1.71%	1.24%

Table H

Figure 8 data: Historical and projected coal production from main regions, 1990-2020 (Mt run of mine coal)

	1990	**1995**	**2000**	**2005**	**2010**	**2015**	**2020**
NSW Underground A	32.03	26.65	34.17	36.13	38.35	40.71	43.21
NSW Underground B	17.74	22.05	26.43	29.46	32.66	35.84	39.19
NSW Open Cut	42.85	59.08	78.96	91.54	102.66	111.69	120.32
Qld Underground A	2.36	4.99	5.20	5.74	6.34	7.00	7.73
Qld Underground B	4.61	11.52	14.85	16.97	19.03	20.00	20.20
Qld Open Cut	87.96	103.46	121.00	133.20	144.63	153.51	161.34
All others	7.66	9.48	6.48	6.97	7.53	8.19	8.95

Table I

Figure 9 data: Production scenarios for black coal, 1990-2020 (Mt run of mine coal)

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**
BAU	195.22	204.54	218.07	223.34	223.12	237.23	243.12	261.21	274.4	280.7	287.1
Higher growth	195.22	204.54	218.07	223.34	223.12	237.23	243.12	261.21	274.4	280.7	287.1
Lower growth	195.22	204.54	218.07	223.34	223.12	237.23	243.12	261.21	274.4	280.7	287.1
	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	
BAU	293.7	300.4	306.6	312.9	319.4	325.9	332.7	338.1	343.5	349.1	
Higher growth	293.7	300.4	307.1	313.9	320.9	328.1	335.4	342.3	349.4	356.6	
Lower growth	293.7	300.4	305.2	310.0	314.9	319.8	324.9	328.8	332.8	336.8	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	
BAU	354.8	360.5	364.8	369.1	373.5	378.0	382.5	387.0	391.6	396.3	
Higher growth	364.0	371.5	378.2	384.9	391.9	398.9	406.1	413.5	420.9	428.6	
Lower growth	340.9	345.0	348.1	351.2	354.4	357.5	360.7	364.0	367.3	370.6	

Table J

Figure 10 data: Methane intensity scenarios for black coal, 1990-2020 (kg CH_4 per tonne of run of mine coal produced)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
BAU (constant intensity)	4.28	4.17	4.09	4.13	3.88	3.55	3.60	3.48	3.49	3.47	3.44	3.41	3.39	3.37	3.35	3.34	3.32	3.30	3.29	3.28	3.28	3.27	3.26	3.26	3.26	3.27	3.27	3.27	3.27	3.27	3.27
Increasing intensity	4.28	4.17	4.09	4.13	3.88	3.55	3.60	3.48	3.49	3.47	3.45	3.44	3.42	3.41	3.41	3.40	3.40	3.39	3.39	3.39	3.39	3.40	3.40	3.41	3.42	3.43	3.43	3.44	3.45	3.46	3.47
Decreasing intensity	4.28	4.17	4.09	4.13	3.88	3.55	3.60	3.48	3.49	3.45	3.41	3.37	3.33	3.31	3.28	3.26	3.23	3.21	3.19	3.18	3.16	3.15	3.13	3.13	3.13	3.12	3.12	3.12	3.11	3.11	3.11

Table K

Figure 11 data: Projected net fugitive methane emissions (Mt CO_2-e) from coal mining, 1990-2020 (Mt CO_2-e)

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**
Gross High	17.5	17.9	18.8	19.4	18.2	17.7	18.4	19.1	20.1	20.5	20.8
Gross BAU	17.5	17.9	18.8	19.4	18.2	17.7	18.4	19.1	20.1	20.4	20.7
Gross Low	17.5	17.9	18.8	19.4	18.2	17.7	18.4	19.1	20.1	20.3	20.6
Recovered (BAU)	-0.8	-0.9	-1.0	-1.3	-1.1	-0.8	-0.7	-2.1	-2.1	-2.3	-2.3
Recovered (Med Gen)	-0.8	-0.9	-1.0	-1.3	-1.1	-0.8	-0.7	-2.1	-2.1	-2.3	-3.2
Recovered (Max Gen)	-0.8	-0.9	-1.0	-1.3	-1.1	-0.8	-0.7	-2.1	-2.1	-2.3	-3.2
HIGHEST Net High (BAU Gen)	16.8	17.0	17.7	18.0	17.1	16.8	17.6	17.0	18.0	18.1	18.5
Net High (Med Gen)	16.8	17.0	17.7	18.0	17.1	16.8	17.6	17.0	18.0	18.1	17.7
Net High (Max Gen)	16.8	17.0	17.7	18.0	17.1	16.8	17.6	17.0	18.0	18.1	17.7
Net BAU (BAU Gen)	16.8	17.0	17.7	18.0	17.1	16.8	17.6	17.0	18.0	18.1	18.4
MIDPOINT Net BAU (Med Gen)	16.8	17.0	17.7	18.0	17.1	16.8	17.6	17.0	18.0	18.1	17.6
Net BAU (Max Gen)	16.8	17.0	17.7	18.0	17.1	16.8	17.6	17.0	18.0	18.1	17.6
Net Low (BAU Gen)	16.8	17.0	17.7	18.0	17.1	16.8	17.6	17.0	18.0	18.0	18.2
Net Low (Med Gen)	16.8	17.0	17.7	18.0	17.1	16.8	17.6	17.0	18.0	18.0	17.4
LOWEST Net Low (Max Gen)	16.8	17.0	17.7	18.0	17.1	16.8	17.6	17.0	18.0	18.0	17.4

	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Gross High	21.2	21.6	22.0	22.5	22.9	23.4	23.9	24.4	24.9	25.4
Gross BAU	21.1	21.4	21.7	22.0	22.4	22.7	23.1	23.4	23.7	24.0
Gross Low	20.8	21.0	21.2	21.4	21.5	21.7	21.9	22.1	22.2	22.4
Recovered (BAU)	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3
Recovered (Med Gen)	-3.7	-4.2	-4.8	-5.3	-5.9	-5.9	-5.9	-5.9	-5.9	-5.9
Recovered (Max Gen)	-4.2	-5.3	-6.4	-7.5	-8.5	-8.5	-8.5	-8.5	-8.6	-8.6
HIGHEST Net High (BAU Gen)	18.9	19.2	19.7	20.1	20.6	21.1	21.6	22.1	22.6	23.1
Net High (Med Gen)	17.5	17.3	17.2	17.1	17.0	17.5	18.0	18.5	19.0	19.5
Net High (Max Gen)	17.0	16.3	15.6	15.0	14.4	14.9	15.3	15.8	16.3	16.9
Net BAU (BAU Gen)	18.7	19.1	19.4	19.7	20.0	20.4	20.7	21.0	21.4	21.7
MIDPOINT Net BAU (Med Gen)	17.4	17.1	16.9	16.7	16.5	16.8	17.2	17.5	17.8	18.1
Net BAU (Max Gen)	16.8	16.1	15.3	14.6	13.8	14.2	14.5	14.8	15.1	15.5
Net Low (BAU Gen)	18.5	18.7	18.9	19.0	19.2	19.4	19.6	19.7	19.9	20.1
Net Low (Med Gen)	17.1	16.8	16.4	16.0	15.7	15.8	16.0	16.2	16.3	16.5
LOWEST Net Low (Max Gen)	16.6	15.7	14.8	13.9	13.0	13.2	13.4	13.5	13.7	13.8

	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Gross High	26.0	26.5	27.1	27.6	28.2	28.8	29.4	30.0	30.6	31.2
Gross BAU	24.3	24.7	25.0	25.3	25.6	25.9	26.3	26.6	26.9	27.3
Gross Low	22.5	22.7	22.9	23.1	23.3	23.4	23.6	23.8	24.0	24.2
Recovered (BAU)	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3
Recovered (Med Gen)	-5.9	-5.9	-5.9	-5.9	-5.9	-5.9	-6.0	-6.0	-6.0	-6.0
Recovered (Max Gen)	-8.6	-8.6	-8.6	-8.6	-8.6	-8.6	-8.6	-8.6	-8.6	-8.6
HIGHEST Net High (BAU Gen)	23.6	24.2	24.7	25.3	25.9	26.4	27.0	27.6	28.3	28.9
Net High (Med Gen)	20.0	20.6	21.1	21.7	22.2	22.8	23.4	24.0	24.6	25.3
Net High (Max Gen)	17.4	17.9	18.5	19.0	19.6	20.2	20.8	21.4	22.0	22.6
Net BAU (BAU Gen)	22.0	22.3	22.7	23.0	23.3	23.6	23.9	24.3	24.6	24.9
MIDPOINT Net BAU (Med Gen)	18.4	18.8	19.1	19.4	19.7	20.0	20.3	20.6	20.9	21.3
Net BAU (Max Gen)	15.8	16.1	16.4	16.7	17.0	17.3	17.6	18.0	18.3	18.6
Net Low (BAU Gen)	20.2	20.4	20.6	20.7	20.9	21.1	21.3	21.5	21.7	21.9
Net Low (Med Gen)	16.6	16.8	17.0	17.1	17.3	17.5	17.7	17.8	18.0	18.2
LOWEST Net Low (Max Gen)	14.0	14.1	14.3	14.5	14.7	14.8	15.0	15.2	15.4	15.6

Table L

Figure 12 data: Actual and projected production, domestic consumption, exports and total production of natural gas (kt CO_2-e), 1990-2020

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Domestic Consumption											
BAU	688.0	655.4	678.6	707.0	736.8	793.1	797.1	818.5	860.0	903.2	976.0
High	688.0	655.4	678.6	707.0	736.8	793.1	797.1	818.5	860.0	914.0	1005.0
Low	688.0	655.4	678.6	707.0	736.8	793.1	797.1	818.5	860.0	892.4	947.0
LNG Exports											
BAU	109.34	185.0	235.6	276.6	320.6	384.1	412.5	401.5	412.5	408.0	408.0
High	109.34	185.0	235.6	276.6	320.6	384.1	412.5	401.5	412.5	408.0	408.0
Low	109.34	185.0	235.6	276.6	320.6	384.1	412.5	401.5	412.5	408.0	408.0
Total											
BAU	797.34	840.4	914.2	983.6	1057.4	1177.2	1209.6	1220.0	1272.5	1311.2	1384.0
High	797.34	840.4	914.2	983.6	1057.4	1177.2	1209.6	1220.0	1272.5	1322.0	1413.0
Low	797.34	840.4	914.2	983.6	1057.4	1177.2	1209.6	1220.0	1272.5	1300.4	1355.0

	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Domestic Consumption										
BAU	1021.1	1052.4	1166.4	1250.4	1305.7	1340.4	1428.1	1470.4	1504.4	1539.8
High	1061.4	1100.5	1243.0	1348.0	1417.1	1460.5	1570.1	1623.0	1665.5	1709.8
Low	980.8	1004.3	1089.8	1152.8	1194.3	1220.3	1286.1	1317.8	1343.3	1369.9
LNG Exports										
BAU	408.0	408.0	408.0	408.0	625.6	625.6	843.2	952.0	1060.8	1169.6
High	408.0	408.0	408.0	408.0	734.4	843.2	1169.6	1278.4	1278.4	1278.4
Low	408.0	408.0	408.0	408.0	625.6	625.6	843.2	843.2	843.2	843.2
Total										
BAU	1429.1	1460.4	1574.4	1658.4	1931.3	1966.0	2271.3	2422.4	2565.2	2709.4
High	1469.4	1508.5	1651.0	1756.0	2151.5	2303.7	2739.7	2901.4	2943.9	2988.2
Low	1388.8	1412.3	1497.8	1560.8	1819.9	1845.9	2129.3	2161.0	2186.5	2213.1

	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Domestic Consumption										
BAU	1595.7	1641.0	1684.3	1711.5	1759.8	1803.5	1848.9	1894.3	1939.7	1985.0
High	1779.6	1836.3	1890.4	1924.4	1984.8	2039.4	2096.1	2152.8	2209.6	2266.3
Low	1411.8	1445.8	1478.2	1498.6	1534.9	1567.6	1601.7	1635.7	1669.7	1703.8
LNG Exports										
BAU	1278.4	1278.4	1278.4	1278.4	1278.4	1278.4	1278.4	1278.4	1278.4	1278.4
High	1278.4	1278.4	1278.4	1278.4	1278.4	1496.0	1713.6	1713.6	1713.6	1713.6
Low	843.2	843.2	843.2	843.2	843.2	843.2	843.2	843.2	843.2	843.2
Total										
BAU	2874.1	2919.4	2962.7	2989.9	3038.2	3081.9	3127.3	3172.7	3218.1	3263.4
High	3058.0	3114.7	3168.8	3202.8	3263.2	3535.4	3809.7	3866.4	3923.2	3979.9
Low	2255.0	2289.0	2321.4	2341.8	2378.1	2410.8	2444.9	2478.9	2512.9	2547.0

Table M

Figure 13 data: Actual and projected emissions of vented CO_2 (kt CO_2-e), 1990-2020

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**
BAU	1966.1	1998.5	2106.1	2243.8	2339.0	2367.8	2387.8	2570.2	2445.2	2537.0	2573.0
High	1966.1	1998.5	2106.1	2243.8	2339.0	2367.8	2387.8	2570.2	2445.2	2537.0	2573.0
Low	1966.1	1998.5	2106.1	2243.8	2339.0	2367.8	2387.8	2570.2	2445.2	2537.0	2573.0

	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
BAU	2625.0	2625.0	2625.0	2625.0	2905.0	2905.0	3185.0	4185.0	5185.0	6335.0
High	2625.0	2652.6	2680.3	2707.9	4015.5	5043.2	6350.8	7378.4	7406.1	7683.7
Low	2625.0	2597.4	2569.7	2542.1	2794.5	2766.8	3019.2	2991.6	2963.9	2936.3

	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
BAU	7335.0	7335.0	7335.0	7335.0	7335.0	7335.0	7335.0	7335.0	7335.0	7335.0
High	7711.3	7738.9	7766.6	7794.2	7821.8	7889.5	7957.1	8024.7	8092.4	8120.0
Low	2908.7	2881.1	2853.4	2825.8	2798.2	2770.5	2742.9	2715.3	2687.6	2660.0

Table N

Figure 14 data : Actual and projected emissions of vented methane (kt CO_2-e), 1990-2020

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**
BAU	78.9	85.5	95.2	90.2	99.6	120.1	123.3	125.6	126.7	130.5	135.4
High	78.9	85.5	95.2	90.2	99.6	120.1	123.3	125.6	126.7	131.6	138.2
Low	78.9	85.5	95.2	90.2	99.6	120.1	123.3	125.6	126.7	129.5	133.0

	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
BAU	138.8	140.3	147.1	151.9	172.7	174.2	196.8	220.4	243.4	268.7
High	142.8	145.8	155.6	162.9	208.3	233.7	281.7	307.7	311.0	318.1
Low	135.4	135.6	139.8	142.4	161.3	161.5	181.4	181.8	181.8	181.8

	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
BAU	292.9	294.8	296.5	297.3	299.3	300.9	302.7	304.5	306.2	307.9
High	323.1	327.3	331.3	334.0	338.5	357.3	376.2	381.0	385.8	389.9
Low	182.7	183.1	183.4	183.0	183.5	183.8	184.1	184.4	184.7	184.9

Table O

Figure 15 data: Actual and projected total emissions (kt CO_2-e) from flaring at oil and gas production and processing facilities, 1990-2020

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**
BAU	4729.2	4380.3	4446.7	4205.5	3804.2	3966.4	3950.0	3520.3	3403.5	3335.5	3268.8
High	4729.2	4380.3	4446.7	4205.5	3804.2	3966.4	3950.0	3520.3	3420.9	3369.6	3319.0
Low	4729.2	4380.3	4446.7	4205.5	3804.2	3966.4	3950.0	3520.3	3386.2	3301.5	3219.0

	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
BAU	3203.4	3139.3	3076.5	3015.0	2954.7	2895.6	2837.7	2780.9	2725.3	2670.8
High	3269.3	3220.2	3171.9	3124.3	3077.5	3031.3	2985.8	2941.1	2896.9	2853.5
Low	3138.5	3060.0	2983.5	2909.0	2836.2	2765.3	2696.2	2628.8	2563.1	2499.0

	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
BAU	2617.4	2565.1	2513.8	2463.5	2414.2	2365.9	2318.6	2272.2	2226.8	2182.3
High	2810.7	2768.5	2727.0	2686.1	2645.8	2606.1	2567.0	2528.5	2490.6	2453.2
Low	2436.5	2375.6	2316.2	2258.3	2201.9	2146.8	2093.1	2040.8	1989.8	1940.0

Table P

Figure 16 data: Actual and projected total emissions (kt CO_2-e) from flaring at oil refineries, 1990-2020

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**
Middle	391.0	425.0	349.6	393.2	333.7	301.8	255.0	235.9	212.5	212.5	212.5
High	391.0	425.0	349.6	393.2	333.7	301.8	255.0	235.9	212.5	212.5	212.5
Low	391.0	425.0	349.6	393.2	333.7	301.8	255.0	235.9	212.5	212.5	212.5

	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Middle	212.5	212.5	191.3	170.0	170.0	170.0	170.0	170.0	170.0	170.0
High	212.5	212.5	212.5	212.5	212.5	212.5	212.5	212.5	212.5	212.5
Low	212.5	212.5	180.6	148.8	148.8	148.8	148.8	148.8	148.8	148.8

	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Middle	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
High	212.5	212.5	212.5	212.5	212.5	212.5	212.5	212.5	212.5	212.5
Low	148.8	148.8	148.8	148.8	148.8	148.8	148.8	148.8	148.8	148.8

Table Q

Figure 17 data: Estimated leakage from gas distribution by State, 1988 – 1998 (kt methane)

	NSW+ACT	VIC	QLD	SA	WA	NT	Australia	Australia (AGA)	Sydney (AGL)
1988	101.61	39.13	5.96	18.59	2.43	0.00	167.72		
1989	100.35	40.11	6.17	22.05	9.94	0.00	178.63		
1990	111.11	47.22	5.74	21.74	9.07	0.00	194.88		86.4
1991	89.82	40.96	6.69	11.60	9.18	0.00	158.26		92.5
1992	92.39	39.36	6.02	21.80	6.26	0.00	165.83		
1993	58.55	39.97	8.92	14.43	10.97	0.00	132.84		
1994	55.70	31.93	10.94	20.53	11.60	0.00	130.69		
1995	47.98	68.82	11.29	24.48	11.39	0.00	163.96		33.3
1996	36.69	58.01	14.36	17.27	10.17	0.00	136.51	96.1	25.5
1997	45.05	64.03	20.09	22.95	13.10	0.00	165.21		21.1
1998	37.35	48.56	17.49	57.29	11.00	0.00	171.68		

Table R

Figure 18 data: Historical and projected gas distribution leakage (Gg CH_4), 1990 – 2020

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**
NSW+ACT	111.1	89.8	92.4	58.6	55.7	48.0	36.7	45.0	37.4	37.5	37.7
Vic	47.2	41.0	39.4	40.0	31.9	68.8	58.0	64.0	48.6	49.0	49.5
Qld	5.7	6.7	6.0	8.9	10.9	11.3	14.4	20.1	17.5	18.4	19.3
SA	21.7	11.6	21.8	14.4	20.5	24.5	17.3	22.9	57.3	22.9	23.0
WA	9.1	9.2	6.3	11.0	11.6	11.4	10.2	13.1	11.0	11.2	11.4
NT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Australia	194.9	158.3	165.8	132.8	130.7	164.0	136.5	165.2	171.7	139.1	141.0

	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
NSW+ACT	37.9	38.1	38.3	38.5	38.7	38.9	39.1	39.3	39.5	39.7
Vic	50.0	50.5	51.0	51.5	52.1	52.6	53.1	53.6	54.2	54.7
Qld	20.2	21.3	21.8	22.3	22.9	23.5	24.1	24.3	24.5	24.8
SA	23.0	23.0	23.2	23.5	23.7	24.0	24.2	24.4	24.7	24.9
WA	11.7	11.9	12.1	12.4	12.6	12.9	13.1	13.4	13.7	13.9
NT										
Australia	142.9	144.8	146.5	148.2	150.0	151.8	153.6	155.0	156.5	158.0

	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
NSW+ACT	39.9	40.1	40.3	40.5	40.7	40.9	41.1	41.3	41.5	41.7
Vic	55.3	55.8	56.4	56.9	57.5	58.1	58.7	59.2	59.8	60.4
Qld	25.0	25.3	25.5	25.8	26.0	26.3	26.6	26.8	27.1	27.4
SA	25.2	25.4	25.7	25.9	26.2	26.5	26.7	27.0	27.3	27.5
WA	14.2	14.5	14.8	15.1	15.4	15.7	16.0	16.3	16.7	17.0
NT										
Australia	159.5	161.1	162.6	164.2	165.8	167.4	169.0	170.7	172.3	174.0

Table S

Figure 19 data: Historical and projected gas distribution leakage (Gg CH_4), 1990 – 2020   (Smoothed – 3 year moving average)

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**
NSW+ACT	111.1	100.5	97.8	80.3	68.9	54.1	46.8	43.2	39.7	40.0	37.5
Vic	47.2	44.1	42.5	40.1	37.1	46.9	52.9	63.6	56.9	53.9	49.0
Qld	5.7	6.2	6.1	7.2	8.6	10.4	12.2	15.2	17.3	18.6	18.4
SA	21.7	16.7	18.4	15.9	18.9	19.8	20.8	21.6	32.5	34.4	34.4
WA	9.1	9.1	8.2	8.8	9.6	11.3	11.1	11.6	11.4	11.8	11.2
NT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Australia	194.9	176.6	173.0	152.3	143.1	142.5	143.7	155.2	157.8	158.7	150.6

	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
NSW+ACT	37.7	37.9	38.1	38.3	38.5	38.7	38.9	39.1	39.3	39.5
Vic	49.5	50.0	50.5	51.0	51.5	52.1	52.6	53.1	53.6	54.2
Qld	19.3	20.3	21.1	21.8	22.3	22.9	23.5	23.9	24.3	24.5
SA	23.0	23.0	23.1	23.2	23.5	23.7	24.0	24.2	24.4	24.7
WA	11.4	11.7	11.9	12.1	12.4	12.6	12.9	13.1	13.4	13.7
NT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Australia	141.0	142.9	144.7	146.5	148.2	150.0	151.8	153.4	155.0	156.5
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
NSW+ACT	39.7	39.9	40.1	40.3	40.5	40.7	40.9	41.1	41.3	41.5
Vic	54.7	55.3	55.8	56.4	56.9	57.5	58.1	58.7	59.2	59.8
Qld	24.8	25.0	25.3	25.5	25.8	26.0	26.3	26.6	26.8	27.1
SA	24.9	25.2	25.4	25.7	25.9	26.2	26.5	26.7	27.0	27.3
WA	13.9	14.2	14.5	14.8	15.1	15.4	15.7	16.0	16.3	16.7
NT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Australia	158.0	159.5	161.1	162.6	164.2	165.8	167.4	169.0	170.7	172.4

Table T

Figure 20 data: Historical and projected gas distribution leakage, as a percentage of gas consumption 1990 – 2020 (leakage smoothed – 3 year moving average)

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**
NSW+ACT	0.083	0.073	0.074	0.047	0.045	0.038	0.027	0.027	0.022	0.021	0.021
Vic	0.016	0.015	0.014	0.013	0.011	0.022	0.018	0.021	0.016	0.017	0.017
Qld	0.023	0.015	0.013	0.018	0.020	0.021	0.025	0.034	0.028	0.025	0.020
SA	0.016	0.010	0.018	0.012	0.015	0.019	0.014	0.018	0.042	0.017	0.016
WA	0.005	0.005	0.003	0.005	0.004	0.004	0.004	0.004	0.003	0.003	0.003
NT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Australia	0.024	0.021	0.021	0.016	0.015	0.017	0.014	0.016	0.016	0.013	0.012

	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
NSW+ACT	0.022	0.021	0.021	0.020	0.019	0.018	0.018	0.019	0.019	0.018
Vic	0.017	0.017	0.016	0.015	0.015	0.015	0.015	0.015	0.015	0.014
Qld	0.018	0.018	0.012	0.011	0.011	0.010	0.009	0.009	0.009	0.009
SA	0.016	0.016	0.016	0.016	0.017	0.017	0.017	0.017	0.017	0.017
WA	0.003	0.003	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002
NT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Australia	0.012	0.012	0.011	0.011	0.010	0.010	0.010	0.009	0.009	0.009

	2011	**2012**	**2013**	**2014**	**2015**
NSW+ACT	0.017	0.016	0.016	0.016	0.015
Vic	0.014	0.014	0.014	0.014	0.014
Qld	0.009	0.009	0.009	0.009	0.009
SA	0.017	0.017	0.016	0.017	0.017
WA	0.002	0.002	0.002	0.002	0.002
NT	0.000	0.000	0.000	0.000	0.000
Australia	0.009	0.009	0.009	0.009	0.008

Table U

Figure 21 data: Projected emissions (as Mt CO_2-e) from natural gas distribution, 1990-2020

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**
BAU	4.09	3.71	3.63	3.20	3.01	2.99	3.02	3.26	3.31	3.33	3.16
High	4.1	3.71	3.63	3.20	3.01	2.99	3.02	3.26	3.31	3.33	3.37
Low	2.9	2.60	2.54	2.24	2.10	2.09	2.11	2.28	2.32	2.33	2.21

	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
BAU	2.96	3.00	3.04	3.08	3.11	3.15	3.19	3.22	3.26	3.29
High	3.40	3.44	3.48	3.52	3.56	3.60	3.64	3.68	3.72	3.76
Low	2.07	2.10	2.12	2.15	2.17	2.19	2.22	2.24	2.27	2.29

	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
BAU	3.32	3.35	3.38	3.42	3.45	3.48	3.52	3.55	3.58	3.62
High	3.80	3.84	3.88	3.92	3.96	4.00	4.04	4.08	4.12	4.16
Low	2.32	2.34	2.36	2.39	2.41	2.44	2.46	2.49	2.51	2.53

Table V

Figure 22 data: Actual and projected emissions of fugitive CO_2 (kt) from gas consumption, 1990 to 2020.

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**
BAU	688.0	655.4	678.6	707.0	736.8	793.1	797.1	818.5	860.0	903.2	976.0
High	688.0	655.4	678.6	707.0	736.8	793.1	797.1	818.5	860.0	914.0	1005.0
Low	688.0	655.4	678.6	707.0	736.8	793.1	797.1	818.5	860.0	892.4	947.0

	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
BAU	1021.1	1052.4	1166.4	1250.4	1305.7	1340.4	1428.1	1470.4	1504.4	1539.8
High	1061.4	1100.5	1243.0	1348.0	1417.1	1460.5	1570.1	1623.0	1665.5	1709.8
Low	980.8	1004.3	1089.8	1152.8	1194.3	1220.3	1286.1	1317.8	1343.3	1369.9

	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
BAU	1595.7	1641.0	1684.3	1711.5	1759.8	1803.5	1848.9	1894.3	1939.7	1985.0
High	1779.6	1836.3	1890.4	1924.4	1984.8	2039.4	2096.1	2152.8	2209.6	2266.3
Low	1411.8	1445.8	1478.2	1498.6	1534.9	1567.6	1601.7	1635.7	1669.7	1703.8

Table W

Figure 23 data: Actual and projected emissions of fugitive CO_2 and methane (kt CO_2-e) from minor oil and gas related sources, 1990 to 2020

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**
BAU	158.5	142.9	152.8	171.9	180.7	185.1	181.6	182.7	192.0	199.9	213.4
High	158.5	142.9	152.8	171.9	180.7	185.1	181.6	182.7	192.0	201.8	218.6
Low	158.5	142.9	152.8	171.9	180.7	185.1	181.6	182.7	192.0	197.9	208.2

	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
BAU	221.8	227.6	248.8	264.4	282.0	288.4	312.0	323.6	333.5	343.8
High	229.1	236.3	262.6	282.0	305.8	317.4	348.7	362.1	369.9	378.1
Low	214.5	218.9	235.0	246.8	261.9	266.7	286.4	292.4	297.1	302.1

	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
BAU	357.8	366.2	374.3	379.3	388.3	396.4	404.9	413.3	421.7	423.9
High	391.0	401.5	411.5	417.8	428.9	446.4	464.1	474.6	485.1	489.3
Low	310.0	316.4	322.4	326.3	333.1	339.2	345.6	352.0	358.4	358.5

Table X

Figure 24 data: Actual and projected combined emissions of CO_2 and methane (kt CO_2-e) from each petroleum related sources, by source, 1990-2020

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**
Venting	3623	3794.2	4105.0	4138.4	4431.6	4890.8	4977.8	5208.3	5106.5	5276.8	5415.9
Flaring	4698.2	4350.9	4415.7	4176.1	3777.9	3938.6	3921.5	3500.8	3381.2	3313.6	3247.3
Oil refineries	386.9	421.4	346.6	389.8	330.8	299.2	252.8	233.9	210.7	210.7	210.7
Minor Sources	158.452	142.9	152.8	171.9	180.7	185.1	181.6	182.7	192.0	199.9	213.4
CO2 from the Burner Tip	688	655.4	678.6	707	736.8	793.1	797.1	818.5	860	903.2	976
Gas Distribution	4092.6	3708.0	3632.8	3198.5	3005.6	2992.5	3018.1	3259.8	3313.8	3332.0	3162.2
Total	13647.12	13072.7	13331.5	12781.6	12463.2	13099.2	13148.9	13204.0	13064.2	13236.2	13225.5

	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Venting	5538.9	5571.1	5713.1	5813.9	6530.8	6563.6	7317.2	8813.6	10297.3	11978.3
Flaring	3182.4	3118.7	3056.4	2995.2	2935.3	2876.6	2819.1	2762.7	2707.5	2653.3
Oil refineries	210.7	210.7	189.6	168.5	168.5	168.5	168.5	168.5	168.5	168.5
Minor Sources	221.8	227.6	248.8	264.4	282.0	288.4	312.0	323.6	333.5	343.8
CO2 from the Burner Tip	1021.1	1052.4	1166.4	1250.4	1305.7	1340.4	1428.1	1470.4	1504.4	1539.8
Gas Distribution	2960.4	3000.3	3039.2	3076.8	3113.0	3149.7	3187.0	3222.4	3255.7	3287.0
Total	13135.2	13180.9	13413.5	13569.3	14335.3	14387.3	15232.0	16761.2	18267.0	19970.7

	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Venting	13486.6	13525.8	13562.1	13577.6	13619.3	13654.8	13691.9	13728.5	13764.7	13800.4
Flaring	2600.2	2548.2	2497.3	2447.3	2398.4	2350.4	2303.4	2257.3	2212.2	2167.9
Oil refineries	168.5	168.5	168.5	168.5	168.5	168.5	168.5	168.5	168.5	168.5
Minor Sources	357.8	366.2	374.3	379.3	388.3	396.4	404.9	413.3	421.7	423.9
CO2 from the Burner Tip	1595.7	1641	1684.3	1711.5	1759.8	1803.5	1849	1894.3	1939.7	1985.0
Gas Distribution	3318.6	3350.5	3382.8	3415.5	3448.6	3482.0	3515.7	3549.9	3584.5	3619.4

Total	21527.4	21600.4	21669.3	21699.8	21782.9	21855.6	21933.3	22011.9	22091.3	22165.2

Table Y

Figure 25 data: Actual and projected emissions of CO_2 and methane (kt CO_2-e) from petroleum related sources, by greenhouse gas, 1990-2020

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**
CO_2	6736.0	6493.7	6603.8	6621.9	6376.9	6559.5	6549.8	6340.2	6180.6	6262.4	6319.2
CH_4	6911.8	6579.0	6727.7	6159.7	6086.3	6539.8	6599.2	6863.8	6883.7	6973.8	6906.3

	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
CO_2	6365.3	6346.5	6391.9	6408.1	6696.4	6684.9	7007.6	8005.7	8996.2	10139.1
CH_4	6769.9	6834.3	7021.6	7161.2	7639.0	7702.4	8224.4	8755.5	9270.8	9831.7

	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
CO_2	11153.4	11157.8	11161.1	11149.0	11159.0	11165.0	11173.5	11182.8	11192.8	11203.5
CH_4	10374.1	10442.5	10508.2	10550.8	10623.9	10690.6	10759.8	10829.1	10898.5	10961.7

Table Z

Figure 26 data: Actual and projected combined emissions of CO_2 and methane (kt CO_2-e) from petroleum related sources under the three scenarios, 1990-2020

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**
BAU	13682.2	13105.8	13365.6	12814.5	12492.5	13129.8	13179.7	13225.6	13088.4	13259.9	13248.8
High	13682.2	13105.8	13365.6	12814.5	12492.5	13129.8	13179.7	13225.6	13105.7	13330.5	13597.8
Low	12454.5	11993.4	12275.7	11854.9	11590.8	12232.0	12274.2	12247.6	12076.8	12193.6	12165.9

	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
BAU	13158.0	13203.3	13435.3	13590.5	14356.2	14407.7	15252.1	16780.9	18286.3	19989.7
High	13799.6	13928.3	14321.3	14619.4	16966.5	18576.1	21027.8	22662.9	22805.1	23281.2
Low	12086.5	12038.4	12114.9	12135.7	12792.0	12752.7	13464.3	13439.2	13400.0	13364.7

	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
BAU	21546.1	21618.7	21687.3	21717.4	21800.2	21872.6	21950.0	22028.2	22107.3	22181.0
High	23494.6	23674.8	23849.2	23972.9	24164.6	24699.1	25239.5	25476.3	25713.5	25892.5
Low	13367.8	13352.7	13335.1	13289.6	13283.0	13269.2	13259.3	13250.2	13242.0	13228.3