A review of regional and global estimates of unconventional gas resources

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Executive summary

It is increasingly claimed that the world is entering a ‘golden age of gas’, with the exploitation of unconventional resources expected to transform gas markets around the world. But the future development of these resources is subject to multiple uncertainties, particularly with regard to the size and recoverability of the physical resource. Even in regions such as the United States where production is relatively advanced, estimates of recoverable resources are contested and are frequently the subject of radical revisions. But this is eclipsed by the much greater uncertainty surrounding unconventional gas resources in the rest of the world.

This report assesses the currently available evidence on the size of unconventional gas resources at the regional and global level. Focusing in particular on shale gas, it provides a comprehensive summary and comparison of the estimates that have been produced to date. It also examines the methods by which these resource estimates have been produced the strengths and weaknesses of those methods, the range of uncertainty in the results and the factors that are relevant to their interpretation.

Taking the best currently available estimates, we find that the global *technically recoverable resource* of shale gas may be in the region of 200 trillion cubic metres (Tcm), with an additional 70 Tcm from tight gas and coal bed methane. For comparison, the global technically recoverable resource of conventional gas is estimated at 425 Tcm of which around 190 Tcm are currently classified as proved reserves. However, the main conclusion of the report is the very high level of uncertainty in these estimates, the inadequate treatment of this uncertainty by the majority of studies, the difficulties in comparing and combining estimates from different studies, and the limitations of currently available estimation methodologies. Future studies should use probabilistic techniques to report on the confidence of estimates and/or produce a range of estimates. Attention must also focus upon a limited number of variables that have a critical influence on the results –such as the anticipated rate of production decline from shale gas wells.

Definitions

This report focuses upon estimates of the *technically recoverable resources* (TRR) of unconventional gas, which are the resources estimated to be potentially recoverable with current technology, regardless of economics. The distinction between *technically recoverable*, *ultimately recoverable* and *economically recoverable* resources is not standardised in the literature and there is considerable overlap between estimates of each from different sources. While technical improvements could increase the amount of gas that is recoverable from a region, numerous economic and other factors (e.g. land access) could lead the ultimately recoverable resource to be substantially less than the TRR.

A major problem with comparing estimates of unconventional gas resources is the use of imprecise or ambiguous terminology. This often results from employing terminology that has been developed for conventional hydrocarbons but is not necessarily appropriate for unconventional resources. For example, the term 'undiscovered resources', is much less appropriate for continuous shale gas formations than for discrete reservoirs of conventional gas, since the existence of those formations is usually well-known and most of the formation may be expected to contain at least some recoverable gas.

Resource estimates are also different from *reserve* estimates, since the latter refer to a subset of discovered resources that have a specified probability of being produced. Shale gas resources are only classified as proved reserves in North America and these currently comprise only a small proportion of the estimated technically recoverable resource. Hence, it is essential to distinguish between resources and reserves when comparing estimates. In general, the controversy and confusion about shale gas resources could be significantly reduced through more careful and consistent use of terms and definitions and through the development of an appropriate standard.

Methods of estimating shale gas resources

Four broad approaches have been used to provide aggregate estimates of regional and global shale gas resources, namely: expert judgement; adaptation of existing literature; bottom up analysis of geological parameters; and extrapolation of production experience. Crossover between these approaches is common, with several studies employing and combining more than one approach. Different studies provide different degrees of explanation as to the methods and assumptions employed and many provide little or no information – a major weakness. At present, the differences in resource estimates between institutions using a similar methodological approach are as significant as those between institutions using different approaches.

The geological approach uses information about the extent and geological characteristics of the rock in an area to estimate the volume of gas that is present and then applies an assumed 'recovery factor' to estimate the TRR. The results are sensitive to the recovery factor assumed and this varies widely from one study to another. While estimation of recovery factors is challenging, little progress appears to have been made in this area for shale gas, even when the geology is relatively well understood.

The extrapolation approach relies upon analysing the production experience to date in a region (termed a 'play') and extrapolating this experience to undeveloped areas of the same region. A similar approach can be used to estimate resource size in separate but geologically similar regions (analogues), but given the wide variations in productivity within and between shale plays, the results are sensitive to the particular analogue that is chosen.

Regional resource estimates using the extrapolation approach are dependent upon the assumed ultimately recoverable resources (URR) from individual wells. These are estimated by fitting a curve to the historical production from a well or group of wells and extrapolating this forward into the future. The appropriate shape of this 'production decline curve' has become a focus of controversy in United States. While production initially declines very rapidly, it remains unclear whether production will continue to decline at the same rate in the future or whether (as is commonly assumed) the rate of decline will fall. Several commentators have suggested that future decline rates have been underestimated and hence both the longevity of wells and the URR per well have been overestimated. To the extent that regional resource estimates are based upon URR estimates for individual wells, this creates the risk that the regional URR will be overestimated as well. Other commentators have contested this interpretation, but the empirical evidence remains equivocal to date owing to the relatively limited production experience.

A second difficulty with the extrapolation approach is the wide variations in the productivity of wells within a single shale play. Production to date has focused upon core areas with the highest productivity and the practice of some sources to assume that comparable production rates will be experienced across the remainder of the play is likely to lead to significant overestimates of the TRR. Similarly, the practice of simply delineating shale areas into more and less productive areas may not adequately reflect their heterogeneity. The large areal extent of many shale plays means that inadequate delineation could have a major effect on the results. However, this source of uncertainty should reduce as drilling continues and the extent to which different areas can be grouped together becomes better defined.

An example of these uncertainties can be seen in the controversy surrounding two recent resource estimates for the Marcellus Shale in the United States. The United States Geological Survey (USGS) estimate the technically recoverable resources of the Marcellus to be 2.4 Tcm while the consultancy INTEK estimated a much higher figure of 11.6 Tcm. There are three major reasons for this difference. First, the two organisations delineated the Marcellus in different ways. Second, the USGS excluded the shale gas in less productive areas of the play, despite this making up 57% of the total INTEK estimate. Third, INTEK assumed that the ultimately recoverable resources from wells in the most productive areas would be three times greater than was assumed by the USGS.

In principle, the reliability of the extrapolation method should improve as production experience increases. Hence, we would expect approaches based upon extrapolation methods to provide more reliable estimates in the medium term. At present, however, the level of uncertainty from this approach appears to be comparable to that from the bottom-up geological approach. Hence, studies of regional TRR should seek to use and compare different approaches and to explore the sensitivity of the results to particular assumptions.

Regional and global resource estimates

Owing in part to the early stage of development of the resource, there are multiple and substantial uncertainties in assessing the recoverable volumes of shale gas at both the regional and global level. Even in United States, there is significant uncertainty over the size of the resource for currently producing regions and considerable variation in the available estimates for those regions. For undeveloped regions where less research has been conducted there may only be a single estimate of resources available, making it impossible to characterise the range of uncertainty. For several regions of the world there are no estimates at all, but this does not necessarily mean that such regions contain only insignificant resources.

The numerous caveats in interpreting regional and global estimates of technically recoverable shale gas resources are described in detail in the report. Our review of current best estimates (Table E.1) suggests that the United States holds around 10% of the global TRR of shale gas, while Europe holds around 8%. These estimates also suggest that shale gas provides around 30% of the global TRR of all natural gas. But shale gas is much more important at the regional level: for example, using our best central estimates of shale gas and current estimates of the other conventional and unconventional gases, shale gas is estimated to represent 46% of the remaining TRR of natural gas in China, 42% in Canada, 52% in Europe and 31% in the United States. As an illustration of the uncertainty in these estimates, the high and low US shale gas estimates are 230% and 64% of the best central estimate respectively – and this is the best characterised resource.

Improvements in technology and geological knowledge could potentially increase these estimates over time. While previous forecasts failed to anticipate the revolutionary developments of the last five years, the technology of shale gas extraction and the geology of the relevant regions are now much better understood. Nevertheless, small increases in the URR/well or the recovery factor could significantly increase estimates of technically recoverable resources.

Overall, given the absence of production experience in most regions of the world, and the number and magnitude of uncertainties that currently exist, estimates of recoverable unconventional gas resources should be treated with considerable caution.

Table E.1 Summary of current best estimates of regional shale gas resources (Trillion cubic metres)

	High	Central	Low
Africa		29.5	
Australia		6.3	
Canada	28.3	12.5	4.7
China	39.8	21.2	1.6
Central and South America		34.7	
Eastern Europe		4.3	
Former Soviet Union	61.2	*32*[1]	2.7
India		1.8	
Middle East	28.7	*16*[1]	2.8
Mexico		11.6	
Other developing Asia	22.1	*12*[1]	1.3
United States	47.4	20.0	13.1
Western Europe		11.6	
Implied global		***213.5***	

Notes:

1. *In some regions it was not possible to develop a central estimate due to an absence of sufficient information, but we provide here a mid-point of high and low estimates for these regions*
2. *All estimates refer to technically recoverable resources, they take no account of economic viability or any other constraints on resource recovery*
3. *The reasons for choosing these particular estimates and/or manner in which they were derived are discussed in detail in the report*

1. Introduction

The development of unconventional gas resources is having an increasing influence on regional and global gas markets, most notably in the United States. But the future potential for unconventional gas production remains contentious, with questions over the size and recoverability of the physical resource being central to the debate. Whilst estimates of unconventional gas resources in the United States remain very uncertain, this is eclipsed by the much greater uncertainty surrounding unconventional gas resources in the rest of the world. This report assesses the available evidence on the size of unconventional gas resources at a global and regional level, including the estimates made to date, the methods by which they have been produced, the range of uncertainty in these estimates and the factors that are relevant to their interpretation. Key messages include the very wide range of uncertainty that exists at this early stage of development of the resource, the confusion created by competing resource definitions and the existence of several notable controversies in unconventional gas resource assessments.

Unconventional gas is frequently defined in terms of the permeability of the source rock. Rock permeability is measured in units called millidarcies (md) and in the past gas in rocks with a permeability of <0.1md had been classified as unconventional [1]. The rate of gas flow into a well is a function of permeability, but also of other variables such as reservoir pressure, well radius and gas viscosity. The use of one measure to define unconventional is therefore of limited usefulness. An alternative approach defines unconventional gas in terms of the technologies needed to produce it at economically viable rates. In this vein the US National Petroleum Council (NPC) define unconventional gas as:

> *'natural gas that cannot be produced at economic flow rates nor in economic volumes unless the well is stimulated by a large hydraulic fracture treatment, a horizontal wellbore, or by using multilateral wellbores or some other technique to expose more of the reservoir to the wellbore.'* [1]

In this report we consider three separate types of unconventional gas:

- **Tight gas** – is gas trapped in relatively impermeable hard rock, limestone or sandstone, sometimes with quantified limit of permeability in md;
- **Coal Bed Methane (CBM)** – is gas trapped in coal seams, adsorbed[1] in the solid matrix of the coal; and

[1] Adsorbed gas refers to gas molecules which have formed some adhesion to the solid surface of the medium in which it is contained.

- **Shale gas** – is gas trapped in fine grained sedimentary rock called shale which has a characteristic 'flaky' quality.

Shale gas and CBM are clearly defined based on the nature of their occurrence in either coal seams or shale. The case of tight gas is more ambiguous since it exists in very similar geological formations to conventional gas, but exhibits relatively slow flow rates. The recent interest in unconventional gas has been spurred mainly by the rapid emergence of shale gas in the United States and so this report, while discussing all of the unconventional gases, will focus in particular on shale gas resources.

The approach adopted throughout this report is informed by a range of techniques that go under the heading of *Evidence-Based Policy and Practice* (EBPP), including in particular the practice of systematic reviews [2]. Core features of the systematic review methodology include exhaustive searching of the available literature and reliance upon the more rigorous studies when drawing conclusions. The report addresses the following four questions:

- *What estimates have been made of unconventional gas resources?* Chapter 2 examines the range of literature on all three types of unconventional gas resources in both Europe and the rest of the world, with a particular focus on shale gas resources. It also discusses the different classifications and definitions of resource estimates, indicating where these are comparable, where they differ, and in which reports these definitions are used.
- *How do we explain the variability in shale gas resource estimates?* Chapter 3 explores the differing methods used to derive shale gas resource estimates and provides an assessment of their relative strengths and weaknesses.
- *What does experience in the Unites States tell us about the resource estimation?* Chapter 4 examines the relevance of production decline rates from individual wells for the estimation of recoverable resources of shale gas. It summarises the recent controversies over this method in the United States and assesses the implications for the robustness of resource estimates.
- *What is the range of uncertainty over unconventional gas resources?* Chapter 5 draws together the evidence in preceding chapters and attempts to characterise the uncertainty surrounding estimates of global unconventional gas, and particularly shale gas, resources. Table 7-1 in Annex 1 provides a breakdown of the evidence base, classifying reports by region, types of gas covered and whether they have been peer reviewed.

2. Estimates: the global unconventional gas resource

2.1 Introduction

This section provides an overview of the literature providing resource estimates for the three unconventional gases. These estimates are presented in a variety of ways that are not always comparable, so it is first important to establish the meaning of the various terms and definitions that are employed. These definitional issues are discussed in detail in Section 2.2.

Section 2.3 provides a breakdown of the various types of literature that exist, categorising studies by date, region, unconventional gases covered and whether they have been peer reviewed. This is followed by a closer examination of the upward trend in shale gas resource estimates over the last two decades, which serves to demonstrate how rapidly knowledge is growing in this area. Section 2.4 examines the various regional and global estimates of shale gas resources, focusing in particular on those made in the last three years, while Section 2.5 puts these into context by comparing them with global estimates of conventional, tight and CBM resources. Using the mean of recoverable resource estimates, it is shown that shale gas may comprise some 30% of the global technically recoverable resource of natural gas. However, the main lesson is the wide variability and large uncertainty in unconventional gas resource estimates.

2.2 Definitions

Resource definitions

Estimates for unconventional gas resources may be provided for different levels of spatial aggregation (e.g. country, region, 'geological play'[2], fields, well), and may either refer to quantities of gas that are estimated to be present or quantities of gas that are estimated to be technically or economically recoverable. In the latter case, these estimates may be expressed probabilistically and/or given to different levels of confidence (e.g. 'probable' or 'possible'). Clear definitions and appropriate interpretation of the figures stated is important as confusion or problems frequently arise when different estimates are incorrectly

[2] A geological play is defined as *'A set of known or postulated oil and gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type.'* [3]

compared. Within this report we will use the specific definitions given below. However, the wide ranging nature of the evidence means that not all of the reports use the same definitions. In some cases the definition being used is not stated explicitly or at all, in others similar terms are used but with slightly different interpretations, while in others ambiguous terms that could refer to any of the definitions are employed (e.g. 'recoverable resources'). This often compounds the problem mentioned above of comparing different estimates. Wherever possible, we compare definitions only when they are equivalent or are judged to be effectively equivalent.

A problem that frequently occurs is the use of terms applicable to conventional gas resources to refer to unconventional gas resources when it would be clearer and less ambiguous to use alternative terms. An example of this is the use of the terms 'discovered' and 'undiscovered'. In contrast to conventional oil and gas resources, the location of the petroleum source for unconventional gas is usually known and so they are not 'undiscovered' in the traditional sense: a well drilled into an area holding unconventional gases will probably yield some volumes of gas. However, if these regions have not been extensively drilled, the precise characteristics of the geology may not be well known and there may be corresponding uncertainty regarding the technical and economic feasibility of gas production.

The Society of Petroleum Engineers (SPE) Petroleum Resources Management System (PRMS) indicates that 'discovered' shale gas resources require *'collected data [that] establish [es] the existence of a significant quantity of potentially moveable hydrocarbons.'* [4] To meet this criterion, the SPE indicates that there must be sufficient evidence of the existence of hydrocarbons from well tests, core and log data, together with evidence that areas which are similar to that under investigation ('analogues') can support commercially viable gas production. This appears to be reasonable requirement, especially given the heterogeneity found in many unconventional gas plays (see Section 3). However it does not allow one to distinguish between geological areas containing *'Resources postulated from geologic information and theory to exist outside of known oil and gas fields'* (the 'traditional' definition of undiscovered conventional hydrocarbons used by the United States Geological Survey ('USGS') [3]) and those areas that are known but do not meet the above requirement. Unless otherwise stated, use of the term 'undiscovered' in this report refers only to the traditional definition – i.e. gas that is estimated to exist outside of known formations.

When reporting unconventional gas volumes, the largest figure that can be given is the initial or *original gas in place ('OGIP')*; this is the total volume of natural gas that is estimated to be present in a given field, play or region. This figure only conveys part of the necessary information to estimate recoverable resources however. The fraction of the OGIP that is estimated to be recoverable – the *recovery factor* – is equally important and can vary substantially depending on the geological conditions, technology used and prevailing gas prices.

The *ultimately recoverable resource ('URR')* of a field or region is the sum of all gas that is expected to be recovered from that field or region over all time. This figure includes any gas that is estimated to be undiscovered (using both of the above interpretations), is not recoverable with current technology, and/or is not currently economic but which is expected to become so before production ceases. The fraction of the gas in place that can be classified as URR therefore takes into account anticipated technological developments, changes in market conditions and/or exploration effort. Estimates of URR will therefore be sensitive to the assumptions used and are likely to be particularly uncertain during the early stages of development of a region. The relationship between URR and the frequently used industry term *'Estimated Ultimate Recovery'* ('EUR') is discussed in Box 1.

Given this inherent uncertainty, an alternative estimate that can be given is the *technically recoverable resources ('TRR').* TRR is the resource figure most frequently provided by the literature, however complete and clear definitions of TRR are rarely provided. Sources reviewed in this report agree that TRR is the fraction of the gas in place that is estimated to be recoverable only with current technology; however ambiguity remains over whether sources include undiscovered volumes of gas from their definitions, and what they mean by the term 'undiscovered'. The US Energy Information Administration ('EIA') [5], for example, first introduces a figure suggesting that TRR excludes undiscovered volumes of gas, but later in the main body of text suggests that it includes undiscovered volumes.

Despite this confusion, the majority of the sources that provide explicit definitions appear to include undiscovered volumes of gas within their estimates of TRR. We therefore employ a definition whereby TRR is gas that is estimated to be recoverable with current technology in: a) discovered formations that are considered to meet the SPE/PRMS requirements; b) discovered formations that are not considered to meet the SPE/PRMS requirements; and c) undiscovered formations.

If cumulative production to date is subtracted from the estimated TRR, the residual is referred to as the *remaining technically recoverable resources (RTRR)*. Sources are also generally poor at indicating whether they report total or remaining technically recoverable resources. In practice, given the infancy of unconventional gas production outside a few areas in North America, these two terms are effectively equivalent in the majority of regions. Where relevant and possible, estimates can be converted to the definition stated (TRR, URR etc.) using the cumulative production data shown in Figure 2-5.

Since not all of the technically recoverable resources will be economic to recover, for example in fields with low production rates and high costs, a further subset of the technically recoverable resources is often given: the *economically recoverable resources ('ERR')*. Similar to TRR, this estimate typically includes any gas that is in: a) discovered formations that are considered to meet the SPE/PRMS requirements; b) discovered formations that are not considered to meet the SPE/PRMS requirements; and c) undiscovered formations. However, unlike TRR, the ERR must be considered to be both technically <u>and</u> economically recoverable. In principle, if the market price was to increase or the production costs decrease, the estimated volume of economically recoverable resources would be expected to increase (and vice versa).

The concept of economically recoverable resources of unconventional gas in undiscovered areas is strange: there appears to be little basis for assumptions about the economic viability of resources within regions which have not yet been found, have not been drilled, and about which very little information is available. Few organisations state explicitly whether undiscovered gas is included within ERR. However when assessing conventional hydrocarbon deposits, the US Bureau of Ocean Energy Management ('BOEM') [6], formerly the Mineral Management Service, and the USGS (for example [7]) report the economically recoverable resources for conventional oil and gas in undiscovered areas on the US Offshore Continental Shelf and in onshore regions respectively. Ejaz [8-9] and Whitney [10], also both report or discuss undiscovered economically recoverable resources, although these appear to be in part based upon data from the US BOEM and USGS. While it is not clear whether undiscovered <u>unconventional</u> gas should be included in ERR, in order to provide consistency with conventional deposits we also include gas in undiscovered areas within our definition of ERR, although it could equally be argued that it should be excluded.

Box 1: Relationship between EUR and URR

The industry standard term for discussing the ultimate recovery from an individual well is the 'Estimated Ultimate Recovery' (EUR) usually denoted EUR/well and also sometimes referred to as the 'productivity'. EUR is essentially identical to URR, although URR is usually preferred when referring to areas or regions larger than a well. As described in detail in Chapters 3 and 4, a common procedure for estimating the recoverable resources from a country or region is through extrapolating values of EUR/well across an area. Confusion can occur over whether these recoverable resources should be interpreted as the <u>ultimately</u> recoverable or the <u>technically</u> recoverable.

It is important to remember that estimates of recoverable resources derived in this way rely upon the extrapolation of existing estimates of EUR/well not just to areas currently being produced but often into new areas which have experienced little or no previous production. The estimates of EUR/well are based upon the use of current technology and so extrapolating them into new areas would be expected to give the recoverable resources in those areas using current technology. Our interpretation is therefore that estimates derived using EUR/well should be seen as the technically recoverable resources (which assume current technology only), unless it is explicitly stated that future technological advances have been incorporated into the analysis. If, by whatever means, economic factors are taken into account, for example if an author estimates that some areas will have very low rates of production or will require excessively complex drilling procedures, and hence discounts resources in these areas, the remaining resources are the economically recoverable resources.

Since EUR and URR are identical terms, we will use the notation of URR/well instead of EUR/well to avoid confusion.

Reserve definitions

The final subset of resources is *reserves.* The exact definition of reserves varies from one source to another, but they are generally those portions of the economically recoverable resources that have been discovered (i.e. fulfil the SPE/PRMS criterion described above) and are estimated to have a specified probability of being produced. Reserve estimates are frequently given to three levels of confidence, namely: *proved reserves* (1P), *proved and probable reserves* (2P) and *proved, probable and possible reserves* (3P). In principle, an estimate of economically recoverable resources includes both reserves and the estimated volumes of undiscovered gas that is considered to be economically recoverable. However, estimates of ERR are rarely given a probabilistic interpretation, so typically it is not clear whether they are based upon 1P, 2P or 3P reserves estimates.

Definitions of the 1P, 2P and 3P reserves vary widely from one country to another and from one company to another, with some employing a deterministic definition (certain qualitative criteria must be satisfied) and others using a probabilistic definition (reserve estimates are based upon a probability distribution of resource recovery). For example, the SPE/PRMS allows one to associate 1P, 2P and 3P with either deterministic or probabilistic definitions. Descriptions of the deterministic definitions are given with, for example, 1P reserves: *'those quantities of petroleum which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable.'*

Under the SPE/PRMS probabilistic definitions 1P, 2P and 3P, reserve estimates are commonly expressed as P90, P50 and P10 respectively. P90 (1P) estimates are then interpreted as the volume of gas production that is estimated to have a 90% probability of being exceeded by the time production ceases. Similarly, P50 (2P) and P10 (3P) estimates refer to volumes of gas production that are estimated to have a 50% and 10% probability respectively of being exceeded. Under this interpretation, 2P (P50) is equivalent to a *median* estimate of reserves. This leads to two additional problems however. The first is whether available reserve estimates, actually correspond to these precise statistical definitions [11]. The second relates to the aggregation of reserve estimates: for example, in deriving regional reserve estimates by summing the reserve estimates of individual fields.

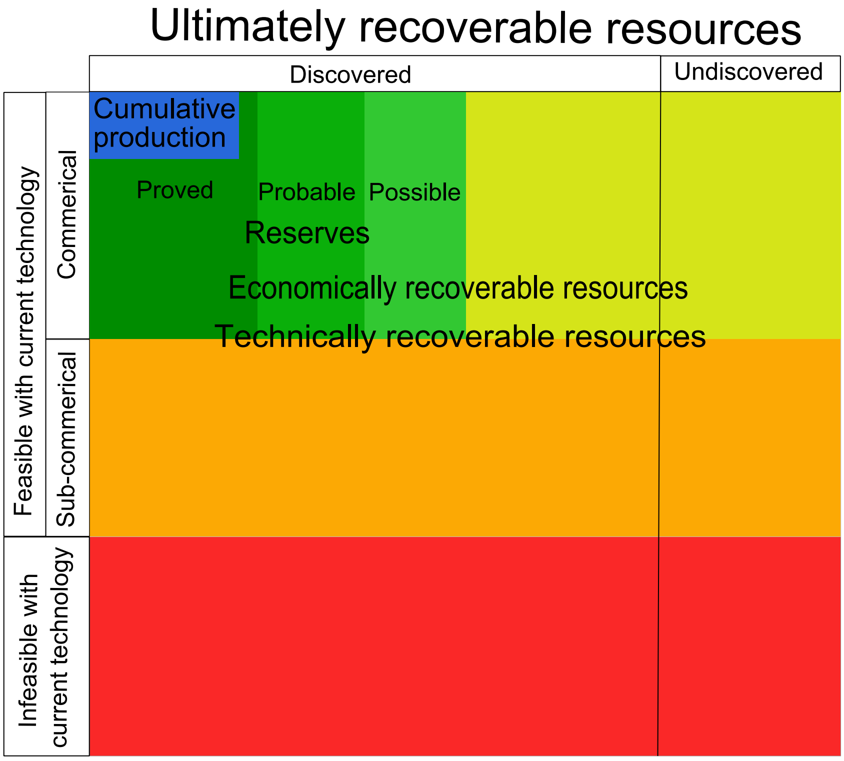
Statistically, it is only valid to arithmetically sum reserve estimates if these correspond to *mean* estimates of recoverable resources. If instead 1P (P90) reserve estimates are arithmetically summed, the aggregate figure will *underestimate* total reserves. Similarly, if 3P (P10) reserve estimates are arithmetically summed, the aggregate figure will *overestimate* total reserves [11-12]. Aggregation of 2P reserve estimates should lead to smaller errors, but the magnitude and sign of these errors will depend upon the difference between *mean* and *median* estimates and hence the precise shape of the underlying probability distribution (which is rarely available). In practice, aggregation of 1P estimates is more common, thereby leading to underestimation of regional reserves.

A comparison of the different resource definitions is presented in Table 2-1 and in the form of a modified 'McKelvey box' in Figure 2-1 [13] . It should be clear from the above, however, that the use of resource and reserve terminology is inconsistent, imprecise and in need of standardisation. Given the early stage production of this resource and the very large uncertainty in all resource estimates, we may anticipate considerable overlap between URR, TRR and ERR estimates - despite the conceptual distinction between them.

Table 2-1: Brief descriptions of resource and reserves for natural gas used in this report

Name	Short description	Includes gas in undiscovere d formations	Includes gas not economically recoverable with current technology	Includes gas that is not recoverable with current technology	Includes gas that is not expected to become recoverable
Original gas in place	Total volume present	✓	✓	✓	✓
Ultimately recoverable resources	Total volume recoverable over all time	✓	✓	✓	
Technically recoverable resources	Recoverable with current technology	✓	✓		
Economically recoverable resources	Economically recoverable with current technology	✓			
1P/2P/3P reserves	Specific probability of being produced				

Figure 2-1: Resources and reserves



Source: Modified from McKelvey [13]

Resources, reserves and the USGS definitions

Although the majority of existing literature uses one or more of the above categories of resources, there is one important exception: the United States Geological Service. The USGS states that it provides estimates of *'undiscovered'* volumes of unconventional gases in different geological areas of the United States. Two of its most recent studies for example provided the *'undiscovered'* resources in areas of the Marcellus, Haynesville and Eagle Ford shales [14-15]. These reports do not have a clear definition of the term *'undiscovered'.*

One interpretation of the resources figures given by the USGS is given in a paper on its methods for estimating unconventional gas[3] resources [16]. The USGS states that *'essentially all of the moveable oil or gas in almost any* [unconventional] *accumulation that can be envisioned has become recoverable from a purely technical standpoint... more restrictive conditions are imposed, to the extent that assessed petroleum volumes must not only be technically recoverable but must also have the potential to be added to reserves'.* This indicates that the criteria required for gas to be included in the resource figures are more stringent than simply requiring the gas to be technically recoverable. Although an updated methodological paper issued in 2010 appears to contradict this by stating *'USGS oil and gas estimates are of technically recoverable resources'* , it later refers to figures being *'potential additions to reserves'* on the required data forms [17]. Both of these methodology papers therefore suggest that figures provided by the USGS should be interpreted as *'potential additions to reserves'*.

A potential confusion that remains is whether the *'potential additions to reserves'* estimates provided by the USGS for shale plays include undiscovered unconventional gas in areas outside known formations. Contacts with the USGS indicate that it does not.

To provide an equal basis for comparing the USGS figures to the estimates provided by other organisations, the USGS figures are hence interpreted as being a subset of remaining technically recoverable resources that exclude both: a) resources that have already been classified as reserves; and b) resources in undiscovered areas. An estimate of reserves and undiscovered resources must therefore be <u>added</u> to the USGS figures in order to determine an estimate of the remaining technically recoverable resources of the US.

Similar to aggregating reserve figures, it is only statistically correct to arithmetically sum estimates of reserves and resources if these correspond to the mean estimates. As indicated above, an estimate of 2P reserves is closest, although not identical, to the mean estimate of

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[3] The USGS uses the term 'continuous' for unconventional oil and gas resources to emphasise the geological difference between these and conventional oil and gas deposits. These terms are essentially identical however.

reserves and so these should be added together to mean estimates of 'potential additions to reserves' and resources in undiscovered areas.

1P reserve estimates within the United States are publically available, while INTEK [18] also provide estimates of US *'inferred reserves'*. The definition of the term *'inferred reserves'* is unclear as it is used by different organisations to mean different things. The USGS in 1995 for example used it to refer to reserve growth in conventional fields[4] [19], while the EIA indicated that it most likely corresponds to 'probable reserves' [5]. We prefer this later definition since it is more recent and more applicable to unconventional gas resources. 'Probable reserves' are different from the description of 'proved and probable' 2P reserves given above in that those reserves classified as proved reserves have been subtracted. 'Probable reserves' would appear, therefore, to be equivalent to 2P minus 1P reserves.

We therefore conclude that an estimate of the remaining technically recoverable resources for the US may be derived from the sum of:

- US proved reserves;
- US inferred reserves;
- the USGS mean estimates of potential additions to reserves in known formations; and
- mean estimates of undiscovered technically recoverable resources.

The addition of contemporaneous estimates of total cumulative production gives an estimate of the total technically recoverable resource of the US.

In addition to the competing definitions of resources and reserves, some other definitions are relevant to the interpretation of published estimates. These are summarised and explained in Box 2.

[4] Reserve growth and hence 'inferred reserves' is indicated by the USGS [19] to be *'resources expected to be added to reserves as a consequence of extension of known fields, through revisions of reserve estimates, and by additions of new pools in discovered fields. Also included in this category are resources expected to be added to reserves through application of improved recovery techniques'*

Box 2: Measurement of natural gas volumes and energy content

Natural gas is generally reported on a volumetric basis either in imperial (cubic feet) or metric (cubic meters) units. In the imperial system, a prefix of 'M' usually denotes a thousand (so MMcf is a million cubic feet) while in the metric system 'm' corresponds to a million (so mcm is a million cubic meters). For resource estimates, the most common prefixes are 'B' for a billion and 'T' for a trillion, both of which are commonly used with cubic meters and feet.

It is also important to know the temperature and pressure at which natural gas volumes are reported. The EIA and API (the American Petroleum Institute) indicate that volumes of gas in the United States are measured at 60°F (15.56°C) and 14.73 psi (1 atmosphere or 101.325kPa) [20–21]. The UK's Department of Energy and Climate Change ('DECC') on the other hand indicates that European natural gas data is generally reported again at atmospheric pressure but at a slightly lower temperature of 15°C [22]. These different definitions correspond to a volumetric difference of around 4%. The majority of the evidence base presented below has been produced by North American institutions or by organisations relying upon North American data and so the volumes presented are most likely to correspond to the EIA and API definitions. At these conditions, cubic feet can be derived by multiplying cubic metres by 35.3 i.e. 1 Tcm = 35.3 Tcf.

Gas can also be reported in terms of 'dry' or 'wet' volumes: dry gas is the volume of gas that remains after any liquefiable or non-hydrocarbon portions of the gas stream has been removed, while wet gas includes both dry gas and these liquefiable or non-hydrocarbon components [23]. Very little of the evidence base states whether dry or wet volumes of the unconventional gases have been reported. SPE/PRMS indicates however that when the gas is used in the end sector separately from any liquefiable fractions contained within it, reported resource figures should be of dry gas [24]. For this reason, it is likely that most of the evidence base reports dry natural gas figures, which will be assumed throughout this report.

Gas can also be measured in terms of energy content. The most common unit as used on the New York Mercantile Exchange (the Henry Hub pricing point) is the British Thermal Unit (BTU), usually reported in MMBTU (million British Thermal Units). An alternative unit used to price gas in the UK on the IntercontinentalExchange ('ICE') at the National Balancing Point ('NBP') is the 'therm', equivalent to 100,000 BTU. One BTU of dry natural gas at 60°F corresponds to around 1,055J.

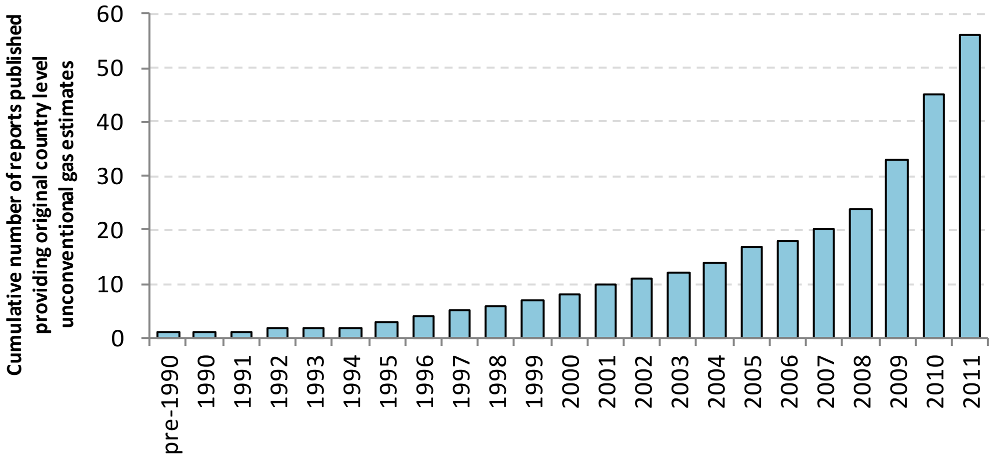
Conversion between volumes and energy depends on the calorific value of the natural gas, which varies over time and with the 'wetness' of the gas. Yearly data from the United States since 1949 indicates that there are around 1,029 BTU in a cubic foot of dry natural gas with a standard deviation of 4 BTU, while wet gas has an energy content around 7.5% higher than dry gas [23][Appendix A4]. One cubic foot of dry natural gas at 60°F is therefore equivalent to around 1.08MJ.

2.3 Sources of data

The focus of this report is *original* estimates of OGIP, TRR or ERR for any of the unconventional gases – although with a particular focus on shale gas. An original estimate for any country or region is one from a source that has either *developed* the estimate itself using recognised methodologies, or *adapted* the estimate from existing sources. Original estimates do not need to come from independent or distinct organisations – indeed, several individuals and organisations have produced multiple estimates. However, the estimates must be *different* in order to be counted as original.

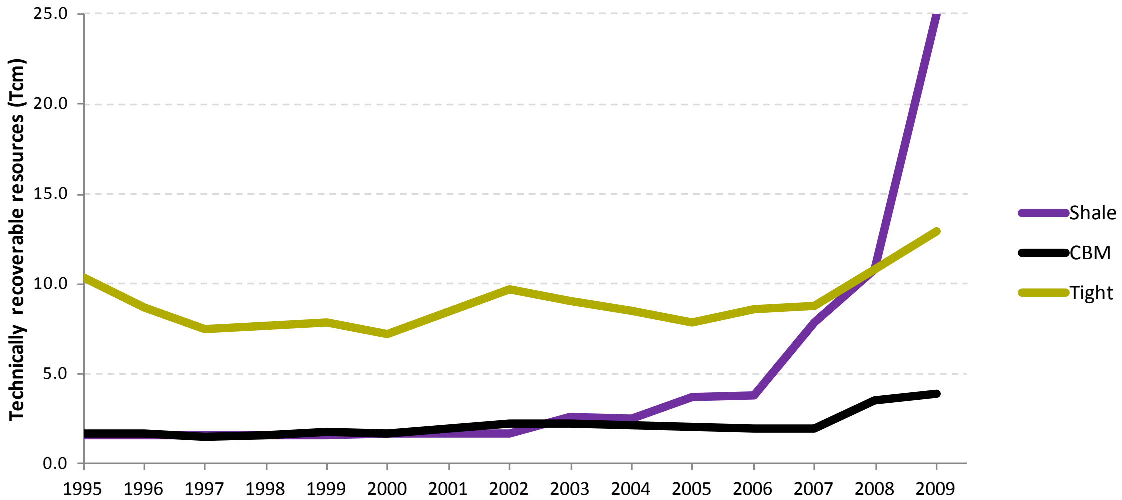
As can be seen in Figure 2-2, there are 56 reports providing original country-level estimates of unconventional gas resources, with 38 of these (~70%) published since the beginning of 2007. The primary motivation for these studies has been the rapid development of US shale gas resources (Figure 2-4), with 52 of the 56 reports providing resource estimates for the United States and/or Canada. Figure 2-4 provides a breakdown of estimates by gas type and region, and indicates whether the reports have been peer reviewed.

Figure 2-2: Cumulative number of reports published providing original country level estimates of any of the unconventional gases



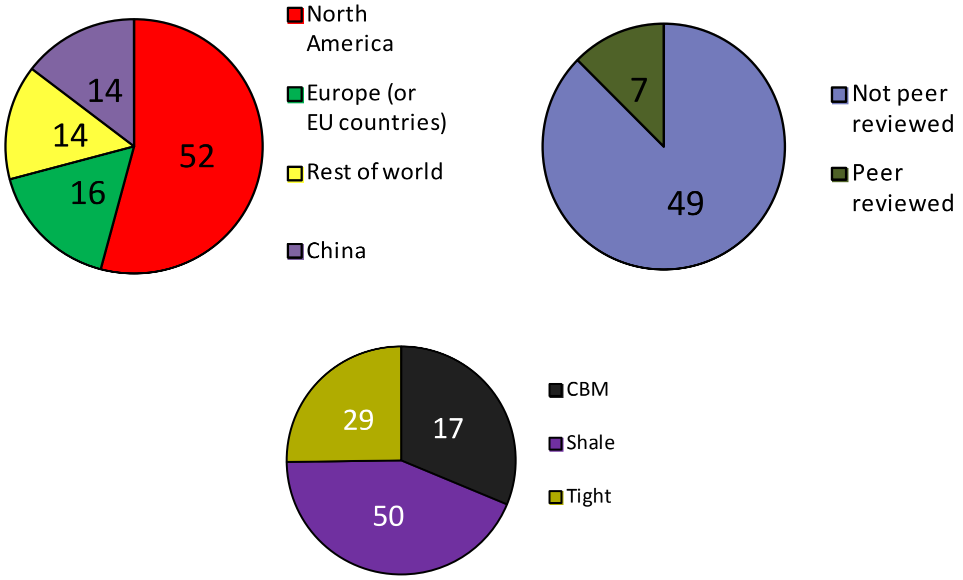
Relatively few organisations or individuals provide periodic resource estimates for all three of the unconventional gases on a consistent basis. One notable exception is the EIA, whose Annual Energy Outlooks ('AEO') have provided estimates of remaining technically recoverable unconventional gas resources in the United States since 1997. Each AEO reports the remaining recoverable resources from two years prior to publication, so the first estimate of remaining recoverable resources is for 1995. Figure 2-3 demonstrates that the estimates of remaining technically recoverable tight gas and CBM have increased by 25% and 134% since 1995, while the estimates for shale gas have increased by a factor of 15. The majority of the increase in tight gas and CBM resource estimates has occurred since 2007, with estimated volumes increasing by around 50% and 100% respectively. Shale gas estimates have increased by 200% in the same time frame.

Figure 2-3: Estimates of remaining recoverable resources for unconventional gases in the United States in successive Annual Energy Outlooks from the US Energy Information Administration



Source: EIA [25]. The 1998 and 1997 AEOs provided estimates of remaining ERR while all others provided estimates of remaining TRR.

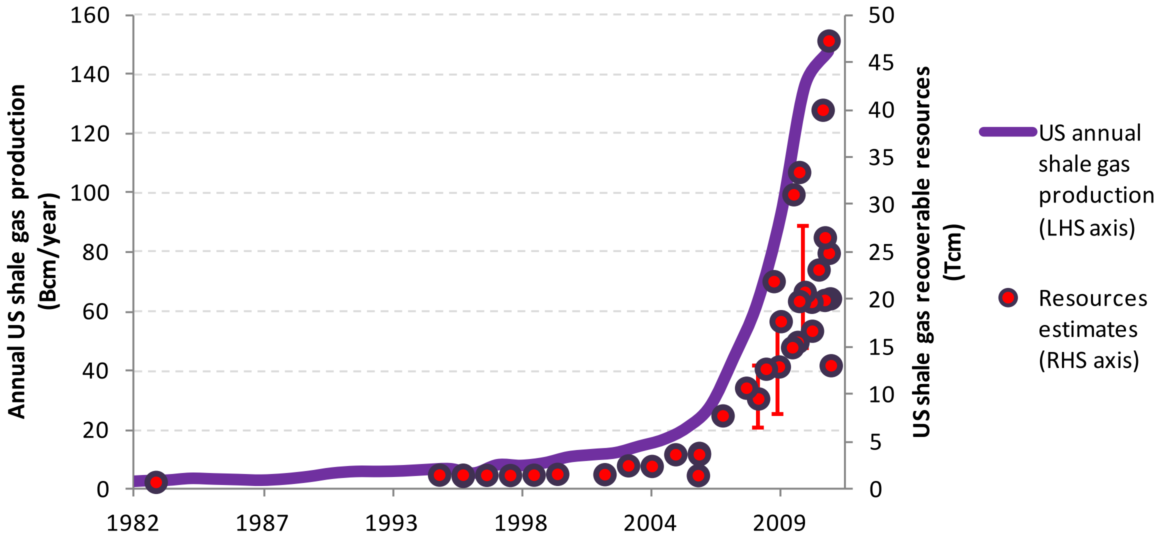
Figure 2-4: Distribution of literature providing original resource estimates by region, source and gas type



Note: A number of reports provide estimates for more than one country or gas type. These are reported separately in each category and so the absolute numbers within each chart will not be identical.

As indicated in Figure 2-4, 52 of the 56 reports have provided estimates for shale gas resources in North America. There is however a huge variation between these estimates and US estimates have risen dramatically in the past six years. Figure 2-5 illustrates the trend in US shale gas resource estimates since 1982. These increased from an average of 1.8 Tcm between 1983 and 2005 to an average of 18.4 Tcm between 2006 and 2010. This rise coincided with a roughly tenfold increase in annual shale gas production over same period. Since the rapid increase in the estimated volume of recoverable resources has coincided with a dramatic increase in drilling across the United States, and therefore a greater knowledge and understanding of the resource base, the more recent estimates are likely to prove more accurate.

Figure 2-5: US shale gas resource estimates and annual production



Source: Production data from 1982- 1989 taken from Slutz [26]; data from 1990 onwards taken from EIA AEO 2011. Graph includes both TRR and ERR resource estimates from all sources. The USGS figure combines all of its latest resource assessments for shale plays of various dates but is plotted at August 2011, the date of the most recent USGS assessment of the Marcellus shale [15].

2.4 Estimates of shale gas resource

Global estimates

This section provides a more detailed look at the estimates made for shale gas resources or shale gas-in-place. It begins with a look at those reports that have considered either global shale gas resources or the shale gas potential in a number of regions worldwide. This is followed by an examination of the estimates that have been made in North America, Europe and in China. For all other regions it was found that only one or two, if any, resource estimates were available and so it was not possible to provide meaningful analysis or comparisons of these.

A total of 50 sources provide original country or regional-level estimates of shale gas resources and these are listed in Table 2-2. No distinction is made between whether total or remaining technically recoverable resources have been reported, as the difference is relatively minor and can be easily transformed from one to the other.

As indicated previously, a number of sources do not indicate whether they have included estimates of undiscovered volumes of shale gas in their estimates of TRR. We can deduce whether this is likely however by examining whether they only consider individual, discovered shale plays, and/or make any reference to the potential for shale gas to be found outside these plays. INTEK [18] estimates that there are 1.6 Tcm of undiscovered shale gas resources in the United States. Hence, it is possible to convert estimates of 'discovered TRR' in the United States to estimates of 'full TRR' by adding in the INTEK figure. There are no estimates of undiscovered shale gas outside the United States since the focus to date has been on those shale plays that are known to exist.

Table 2-2: Shale gas reports providing original country level estimates by date, countries or regions covered and type of resource estimate

Author/organisation	Date of report	Countries/regions covered	Resource estimate
Mohr & Evans [27]	Sep-11	Continental regions	URR
USGS[1]	Aug-11	United States	'Potential additions to reserves'
Medlock *et al.* [28]	Jul-11	9 North American, European and Pacific countries	TRR[2]
INTEK (for EIA) [18]	Jul-11	United States	'Unproved, discovered TRR'[3]
ICF (Petak) [29]	May-11	United States. Canada	ERR[4]
ARI (Kuuskraa) [30]	May-11	United States	TRR
EIA (AEO) [25]	Various[5]	United States	TRR (2010 – 1999) ERR (1998 & 1997)
Potential Gas Committee [31]	Apr-11	United States	TRR
ARI (for EIA) [32]	Apr-11	32 individual countries	OGIP and TRR
ICF (Henning) [33]	Mar-11	United States, Canada	ERR[4]
ARI (Kuuskraa) [34]	Jan-11	United States	TRR
Caineng *et al.* [35]	Dec-10	China	OGIP
Medlock & Hartley [36]	Oct-10	United States, Canada	TRR
ARI (Kuuskraa) [37]	Oct-10	United States	TRR
World Energy Council[38]	Sep-10	Nine continental regions	OGIP
Mohr & Evans [39]	Jul-10	United States, Canada	URR
MIT (Moniz) [40]	Jun-10	United States	TRR
Dawson [41]	May-10	Canada	ERR
Skipper [42]	Mar-10	United States, Canada	TRR
Hennings [43]	Mar-10	United States	OGIP and TRR
ARI (Kuuskraa) [44]	Mar-10	United States, Canada	TRR
Petrel Robertson Consulting [45]	Mar-10	Canada	OGIP
IHS CERA (Downey) [46]	Jan-10	United States, Canada	TRR
DECC (Harvey and Gray) [47]	Jan-10	UK	TRR
ARI (Kuuskraa) [48]	Dec-09	United States, Canada, Poland, Sweden, Austria, South Africa	'Recoverable resources'
Potential Gas Committee [49]	Jun-09	United States	TRR
Theal [50]	May-09	United States, Canada	OGIP and TRR
ICF (reported by [8])	Mar-09	United States	ERR[4]
IHS CERA [51]	Feb-09	Europe	TRR
Wood Mackenzie [52]	Jan-09	Europe	TRR
ICF (Vidas & Hugman) [53]	Nov-08	United States, Canada	OGIP and TRR
Navigant Consulting [54]	Jul-08	United States	TRR
ARI (Kuuskraa) [55]	Jul-07	United States	URR
Sandrea [56]	Dec-05	United States, Global	'Recoverable reserves'
Laherrere [57]	Jun-04	Global	URR
Kuuskraa [58]	Jan-04	United States	TRR and URR
Rogner [59]	Jan-97	Continental regions	OGIP
Kuuskraa & Meyers [60]	Jan-83	United States, Canada, ROW	TRR

1. **USGS estimate based on Coleman *et al.* [15], Higley *et al.* [61], Houseknecht *et al.* [62], Schenk *et al.* [63], Swezey *et al.* [64], Swezey *et al.* [65], Pollastro *et al.* [66] Higley *et al.* [67], Milici *et al.* [68] and USGS [69].**
2. **Medlock indicates that resource should be commercially viable so his definition, although described as technically recoverable resources, could be closer to ERR. This is discussed in further detail in Section 3.2.**
3. **TRR can be derived through adding the EIA and INTEK figures for contemporaneous proved and inferred reserves, undiscovered resources, and 'unproved discovered technically recoverable resources', all of which are reported separately.**
4. **ICF's 2011 report [29] indicates that there is a total of 61.5 Tcm of economically recoverable resource in the US and Canada. It provides a supply cost curve indicating that this volume is only recoverable at gas prices greater than \$14/Mcf. Since this price is four times higher than current gas prices (around \$3.5/Mcf on 15th December 2011), we consider that all of ICF's estimates are better interpreted as TRR.**
5. **There have been a total of 15 Annual Energy Outlooks between 1997 and 2011. The AEO in 2003 used the same unconventional gas figures as 2002, while the 2011 estimate was based entirely on INTEK (2011) and so is reported separately. There are therefore a total of 13 AEOs included in this row.**

On a global scale, the estimate made by Rogner [59] formed the basis of nearly all estimates of the shale gas resource base outside North America until around 2009. As discussed in more detail in Chapter 3, Rogner estimated the original gas in place for each unconventional gas within eleven continental regions as shown in Table 2-4. Rogner's estimate of the global OGIP for unconventional gas was 920 Tcm, of which 50% was shale gas. Rogner did not provide a breakdown of OGIP in any individual countries, nor did he suggest or provide a fraction of these values that he considered recoverable, however numerous organisations have derived technically recoverable resources by taking certain percentages of Rogner's figures. Some values suggested or used include 15% by Mohr and Evans [39], 10-35% by MIT [8], and 40% by ARI [48] and the IEA [70].[5] To put these recovery factors in context, ARI [32] uses a range of 15% - 35% for the recovery of shale gas from each geological area analysed while recovery from conventional gas wells is often around 70-80% [71].

Table 2-3: Estimates of original shale gas in place by Rogner [59]

Region	Original shale gas in place (Tcm)
North America	108.3
Latin America and the Caribbean	59.7
Western Europe[6]	14.4
Central and Eastern Europe[7]	1.1
Former Soviet Union	17.7
Middle East & North Africa	71.8
Sub-Saharan Africa	7.7
Centrally Planned Asia & China	99.4
South Asia	65.2
Other Pacific Asia	8.8
Pacific OECD	0
Total	**454.1**

Using Rogner's OGIP estimates, a 15% recovery factor would give a global estimate of 68 Tcm for the TRR of shale gas, while a 40% recovery factor would increase this to 181.3 Tcm. Hence, the range of 15-40% in the recoverable fraction of Rogner's OGIP corresponds to an uncertainty of around 113.3 Tcm on a global scale. This approximates to

[5] The IEA does not explicitly state the recovery factor used for each of the three unconventional gases, but provides figures from which it can be calculated.

6 Western Europe is described as consisting of: Andorra, Austria, Azores, Belgium, Canary Islands, Channel Islands, Cyprus, Denmark, Faeroe Islands, Finland, France, Germany, Gibraltar, Greece, Greenland, Iceland, Ireland, Isle of Man, Italy, Lichtenstein, Luxembourg, Madeira, Malta, Monaco, Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, Turkey and the United Kingdom.

7 Central and Eastern Europe is described as consisting of: Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Czech Republic, FYR Macedonia, Hungary, Poland, Romania, Slovak Republic, Slovenia, and Yugoslavia.

one third of the Bundesanstalt für Geowissenschaften und Rohstoffe (BGR)'s estimate remaining global technically recoverable resource of conventional gas (~425 Tcm) [72].[8]

A more recent report by the World Energy Council ('WEC') in 2010 also provided OGIP figures for regions similar to those used by Rogner [38], although combined South Asia, Other Pacific Asia and OECD Pacific into one region. Some of the estimates provided are significantly different to Rogner's, with the estimated OGIP for Latin America and Centrally Planned Asia & China decreasing to 10.6 Tcm and 10.5 Tcm (a reduction of around 80% and 90% respectively from Rogner's figures) while the OGIP estimated for the Former Soviet Union is 153 Tcm (an increase greater than eightfold). Regarding recovery factors, it is mentioned that *'nearly 40% of this endowment would be economically recoverable'*, corresponding to a global ERR of around 170 Tcm. Given that the costs of extraction and market conditions at the time when the resource will be extracted is highly uncertain, particularly in areas where there is currently no shale gas production, it is likely that the WEC's estimate actually corresponds more closely to TRR rather than ERR.

Two other recent independent reports have been undertaken which estimate technically recoverable shale gas resources on a global scale [28, 32]. Nevertheless, even these do not attempt to assess all shale plays and indicate that there is limited geological information available for a number of plays anticipated to hold shale gas.

ARI [32] for example ignores regions where there are large quantities of conventional gas reserves (Russia and the Middle East) or where there is insufficient information to carry out an assessment. Similarly, Medlock *et al.* [28] only assess the shale gas potential in six countries[9] outside North America and justify the exclusion of unassessed shales by suggesting that they are unlikely to be economically recoverable. Hence, neither review provides a global estimate of technically recoverable shale gas resources.

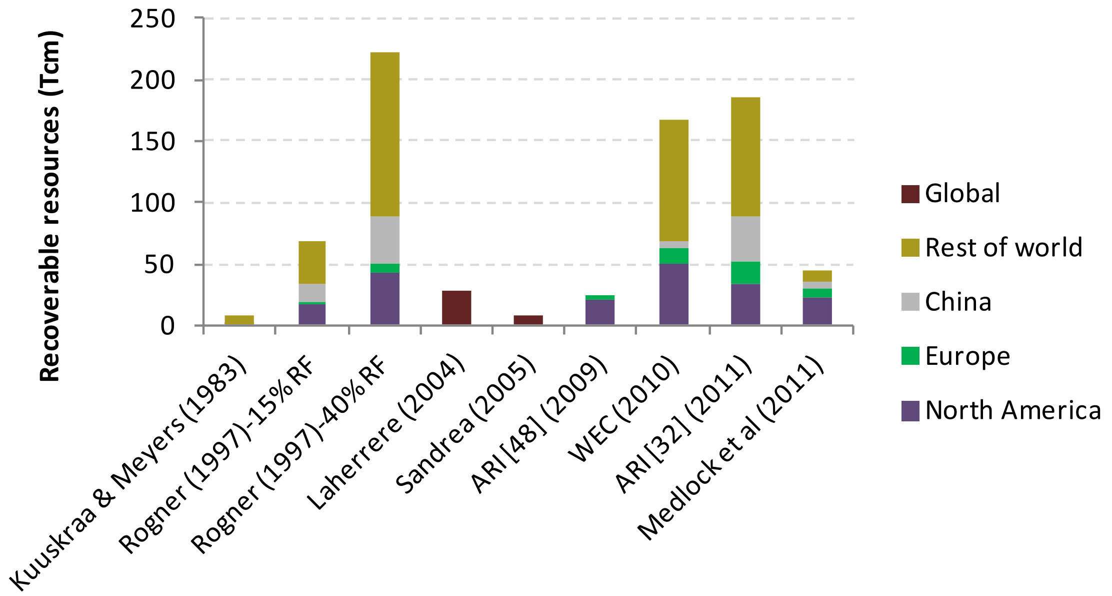
ARI [48] produced an earlier and much smaller estimate in 2009 but noted a number of other shale plays were likely to contain resources and had not been quantitatively assessed and that its estimate was therefore anticipated *to 'grow with time and new data'* [48]. The majority of the increase between ARI's estimate in 2009 and 2011 comes from this increase in the geographical coverage of the later survey (see Figure 2-6). Finally, three other estimates of global shale resources have been made [56-57, 60], but these were produced

[8] 187 Tcm, or 44% of the total remaining technically recoverable resources of conventional gas, is classified as proved reserves in the 2011 BP statistical review [73]. Note however that this 'proved' figure covers all four types of gas (conventional, tight CBM and shale) to differing degrees in different countries, depending upon the state of development of the resource.

[9] The nine countries analysed are: the United States, Canada, Mexico, Austria, Germany, Poland, Sweden, China and Australia.

some time before the recent increase in US production, and are predominantly based upon expert judgment.

Figure 2-6: Estimates of global shale gas resources by sources considering regions outside North America

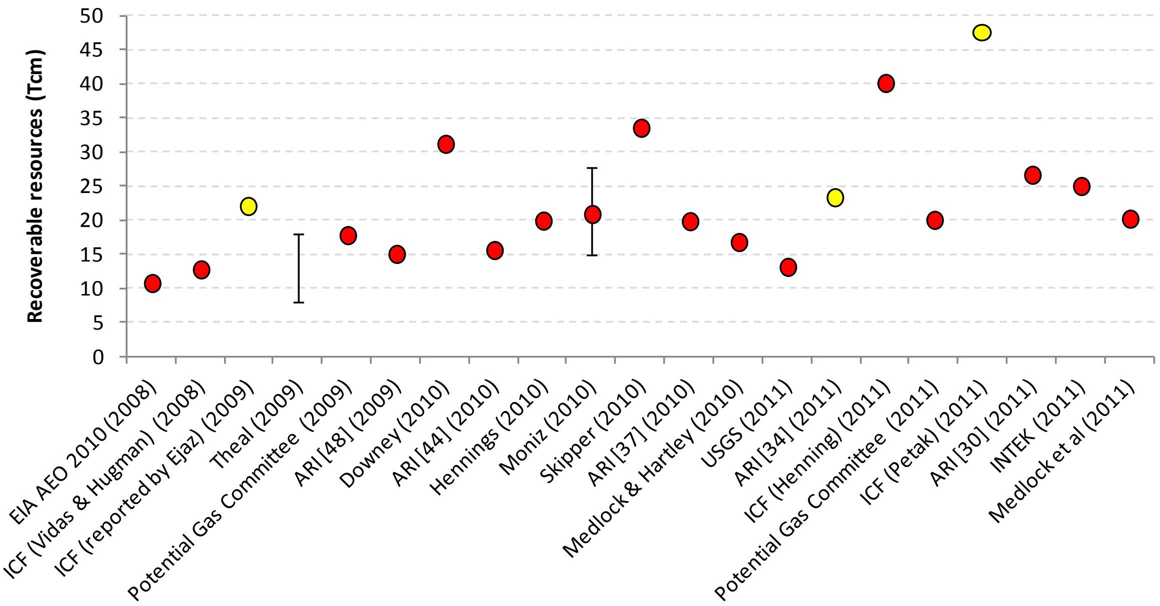


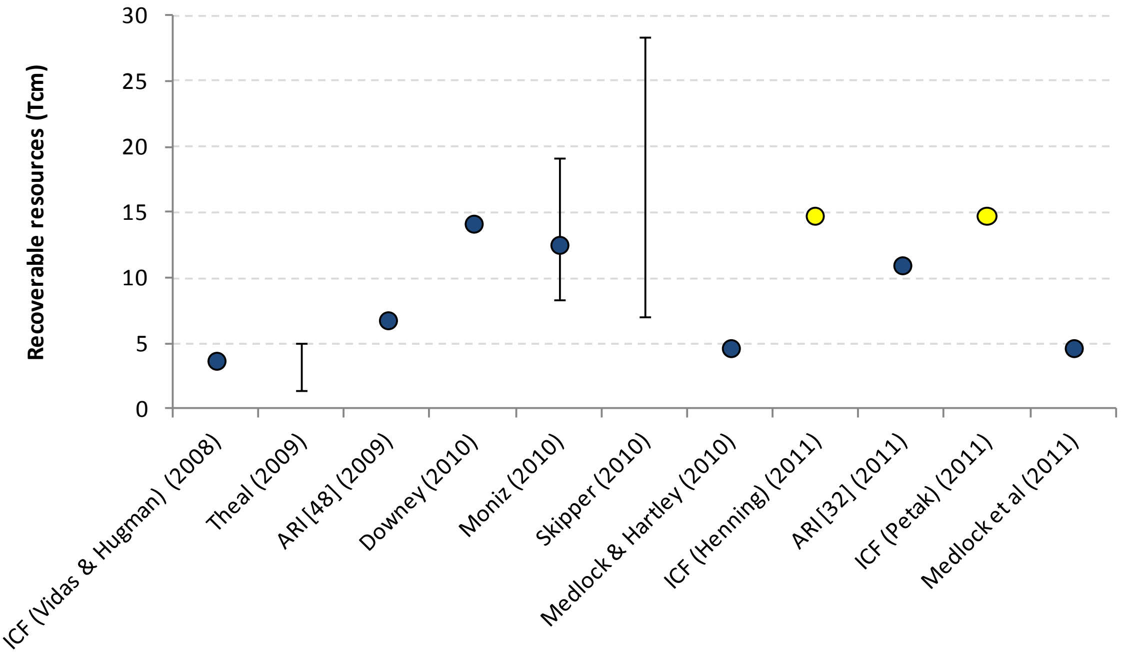
Note: Different studies cover different countries and regions and none provide a truly global estimate. Resource definitions also differ; both in terms of what is reported and how this is defined and estimated (see Table 2-2). Laherrere's estimate is URR, while Medlock's are likely to be closer to ERR. The OGIP estimate by Rogner is converted to TRR using 15% and 40% recovery factors and the WEC's estimate to ERR using a 40% recovery factor.

North America

As can be seen from Figure 2-5, estimates of the recoverable resources of shale gas within United States have been increasing rapidly, with the more recent reports likely to provide more accurate estimates. Figure 2-7 therefore presents the more recent reports, chosen here to be those produced since 2008, that provide estimates of the recoverable resources of shale gas within the United States and Canada. There have been a total of eighteen reports providing estimates for the United States and twelve for Canada over this period. Some of these, for example those by ICF [29] or ARI [37] are updates of older reports but are reported here separately. It is noticeable that despite the variation in resource estimates between these reports (even those of similar dates), only three of these give a range of uncertainty in the values quoted. Even within this short timeframe, the estimates made in the past year are higher on average than those made in 2008.

Figure 2-7: Estimates made since 2008 of the technically recoverable shale gas resources in the United States (top) and Canada (bottom). Points in yellow correspond to estimates that were stated as referring to economically recoverable resources.



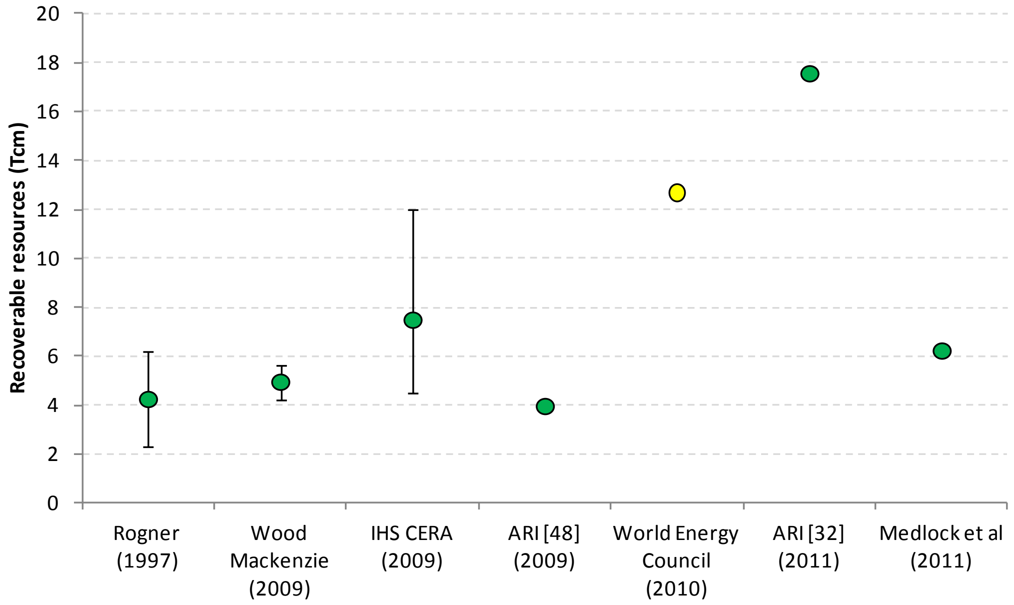


Note: Some sources did not report a central estimate, only giving a range of values. The WEC [38] did not provide a split between the United States and Canada and so is not included.

Europe

In contrast to the evidence base for United States, very few estimates of the recoverable resource of shale gas within Europe are available. A number of reports have been published since 2009, however, that focus specifically on the technically recoverable resources in Europe. These are presented in Figure 2-8, and range from 2.3 Tcm to 17.6 Tcm, with a mean of 7.1 Tcm. Note that ARI's estimate from 2009 ignored a number of plays.

Figure 2-8: All estimates of the technically recoverable resources of shale gas within Europe. The point in yellow corresponds to an estimate that was stated as referring to economically recoverable resources.

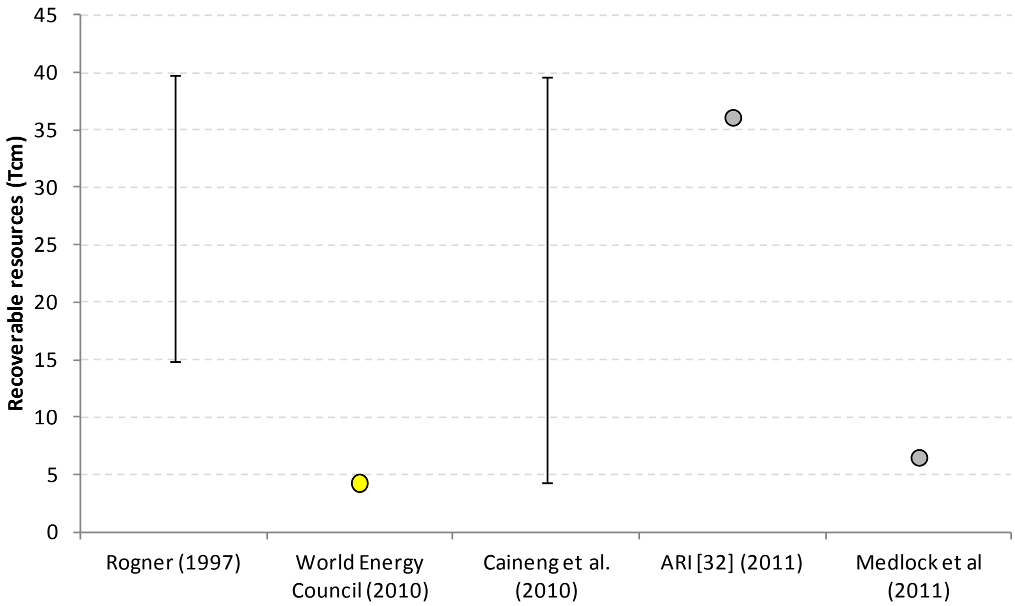


Note: **The range for Rogner's estimate is derived using a 15 – 40% recovery factor within Western and Eastern Europe. Values for Wood Mackenzie and IHS CERA come from Weijermars *et al.* [74].**

China

Relatively few estimates of the Chinese shale gas resource are available and even fewer provide an estimate of the TRR or ERR, preferring instead to estimate the OGIP. ARI [32] estimates an OGIP of 144.5 Tcm and a TRR of 36.0 Tcm, which suggests a recovery factor of around 25%. Since there is little agreement on this factor, we have again converted any estimates of OGIP into TRR using a range of recovery factors between 15-40%. The range in the estimate of Caineng *et al.* [35] results from applying this variation in recovery factor to the range of OGIP provided by the authors (28.3-99.1 Tcm). The World Energy Council's estimate is for 'Centrally Planned Asia' (which includes Cambodia, Hong Kong, PDR Korea, Laos, Mongolia and Vietnam) as well as China but for illustrative purposes we assign all of the resource to China. The variation in currently available estimates for TRR in China is therefore even larger than that in Europe and North America.

Figure 2-9: All estimates of the technically recoverable resources of shale gas within China. The point in yellow corresponds to an estimate that was stated as referring to economically recoverable resources.



2.5 Shale gas estimates in context

Table 2-5 summarises the ranges and mean estimates of the technically recoverable shale gas in the above regions and globally. Within each region, the shale gas estimates are derived using the sources shown in Figures 2-7 to 2-9. As explained previously, it is considered that the estimates of shale gas ERR given by ICF [29] and WEC [38] are better described as TRR and so their figures are included when calculating the mean resource estimates. In addition, when sources have provided multiple estimates (e.g. ARI/Kuuskraa), only the latest update is included in the calculation of the mean resource estimate.

This table also includes estimates of the remaining technically recoverable resources of conventional gas, CBM and tight gas held by each of the regions. The conventional estimates come from BGR [75], while the tight and CBM estimates come from a variety of sources with a different number of reports or articles available for each of the regions.

As mentioned in Section 2.4, given the focus on the resource potential of those shale plays that are known to exist, there have been no estimates of shale gas resources from shale plays outside the United States that are estimated, but not known, to exist. It is therefore difficult to determine what the relative magnitude of shale gas in undiscovered shale plays worldwide is likely to be compared to those in known shale plays. Stevens [76] indicates that shale gas plays tend to overlie conventional oil and gas wells. He therefore concludes that countries with a history of onshore oil and gas production (e.g. the United States), will have a higher degree of knowledge of the shale gas resource, and hence less potential for undiscovered shale plays, compared to countries with relatively little history of onshore production (e.g. most European countries). This can be demonstrated by observing that within the United States estimated volumes of technically recoverable resources of undiscovered shale gas only make up 7% of the total shale gas TRR.

Nevertheless, there has been extensive geological mapping of the rocks underlying many countries worldwide. Despite limited onshore drilling in the UK, for example, various geological studies provide a complete cross section of the rocks throughout the UK [47]. There is therefore unlikely to be any undiscovered shale gas plays in the UK. While this may not be case for all countries, it suggests that the volumes of gas in currently undiscovered shale plays will likely be overshadowed by volumes in discovered but undeveloped plays.

Table 2-4: Mean estimates of remaining technically recoverable resources of conventional gas, CBM, tight gas and shale gas provided by the evidence base (Tcm)

Region	Conventional	Tight	CBM	Shale		
				Lowest estimate	Mean of estimates	Highest estimate
United States	27.2	12.7	3.7	8.0	23.5	47.4
Canada	8.8	6.7	2.0	1.4	11.1	28.3
Europe	11.6	1.4	1.4	2.3	8.9	17.6
China	12.5	9.9	2.8	4.2	19.2	39.8
(Implied rest of world)	(364.9)	(14.6)	(15.6)		(34.7)	
Global	**424.9**	**45.4**	**25.5**	**7.1**	**97.4**	**186.4**

Sources: Shale gas reports in Figures 2-7 to 2-9 and [25, 27, 31, 34, 38, 40-41, 48, 54, 56, 59, 75, 77]
Notes: Implied rest of world figures derived by subtracting each mean regional estimate from the mean global estimate.

As noted previously, the global estimates do not all cover the same regions, do not use the same definitions and are based on a number of different methodologies and assumptions (e.g. for recovery factor) which helps to explain the significant variation in estimates. The mean estimate is also skewed by the low estimates of Sandrea [56] and Laherrere [57] which are both relatively old and based on expert judgment alone. If these are excluded, the mean estimate increases to 130 Tcm. The lowest global estimate then becomes that provided by Medlock *et al.* [28] at 42.9 Tcm.

Focusing on the mean estimates within Table 2-5, the figures suggest that the United States holds around 25% of the global TRR of shale gas, while Europe holds around 10%. Similar percentages are obtained in both regions if the highest estimates are compared.

It is also of interest to place global shale gas resources into context with the global remaining recoverable resources of conventional gas. The mean estimate given by the current literature of the global TRR for shale gas is around 23% of the remaining recoverable resources of conventional gas, which increases to 30% if Sandrea's and Laherrere's shale gas estimates are excluded.

The remaining global TRR of all natural gas consists of the sum of the mean estimates of conventional gas and the three unconventional gases. On a global scale, shale gas is estimated to make up 16% of the total figure of 593.2 Tcm. On a regional basis, however, shale gas can form a much larger proportion of the remaining TRR. For example, using the mean estimates, shale gas is estimated to represent 43% of the remaining TRR of natural gas in China, 39% Canada, 38% in Europe and 35% in the United States. This suggests that the impact of shale gas is likely to be greater at the regional level than at the global level.

3. Methods for estimating the recoverable resources of shale gas

3.1 Introduction

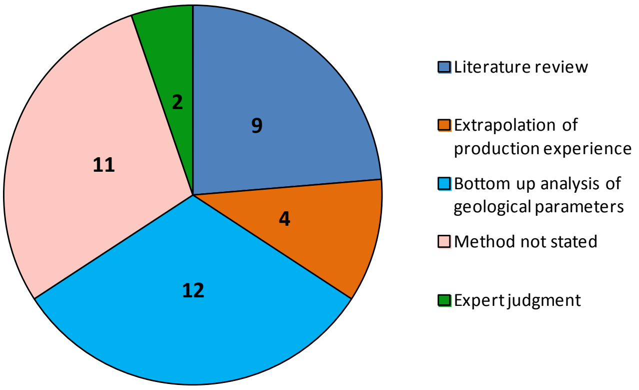
This chapter provides an overview and critique of the methods employed to estimate the technically recoverable resources of shale gas.

Four broad approaches have been used to estimate recoverable volumes of shale gas, namely: a) expert judgement; b) literature review/adaptation of existing literature; c) bottom up analysis of geological parameters; and d) extrapolation of production experience. Crossover between these approaches is common, with several reports employing and combining more than one approach.

Different reports provide different degrees of explanation of the methods employed, and in many cases little or no information is given – a major weakness. Hence, judgment is frequently required when identifying and classifying the approach that has been taken. Figure 3-1 (which is based upon Table 7-1), classifies the approaches used by each of the reports. Reports labelled as 'Method not stated' provide little or no description of the methods used and provide insufficient information to allow this to be identified.

Section 3.2 provides a brief description and explanation of each of these approaches and illustrates this by discussing the specific approach taken by three reports in more detail. Not all reports use an identical approach, however, and differences such as the definition and terminology used for relevant variables, the inclusion or exclusion of particular parameters, the reliance upon different sources of information, and values chosen for subjective parameters are common. These differences are likely in turn to have a significant influence on the results. Section 3.3 evaluates and compares the methodological robustness of each approach; Section 3.4 provides an overview of the role technology could play in increasing current estimates of technically recoverable shale gas resources, while Section 3.5 concludes.

Figure 3-1: Approaches used by all reports providing original country level shale gas resource estimates



Note: the EIA AEOs are only included once

3.2 Description of approaches

The four approaches to estimating resource size that are used in the literature are briefly described below. The order in which they are discussed reflects the relative weight that may be given to their results, with the least robust first.

Expert judgment

The first category is used by only two authors [56-57] who do not cite any other sources or indicate the method they have used to develop their resource estimate. The estimates provided therefore appear not to have been derived using any rigorous or repeatable method but rather based upon their own opinions of technology and geology and are likely to be very subjective.[10]

Literature review/adaption of existing literature

A number of reports rely upon estimates made by others and collate or adapt these to determine their own estimates. Some sources, for example MIT [40] and Mohr and Evans [27, 39], analyse a number of estimates and use the variation between these to identify a range of uncertainty for regional or country values. Others also use a literature review but augment this data with additional primary research. Navigant Consulting [54], for example, conducted a survey of natural gas producers and used this to provide a higher bound on its estimates, which it called the *'maximum reported'* estimate for each shale play. The WEC [38] appears to have used a literature review, but provides no description of its

[10] This category differs from those reports classified as 'Method not stated', as it is thought that these estimates have been derived using one of the four broad approaches described; it is not possible to determine which approach has been used however.

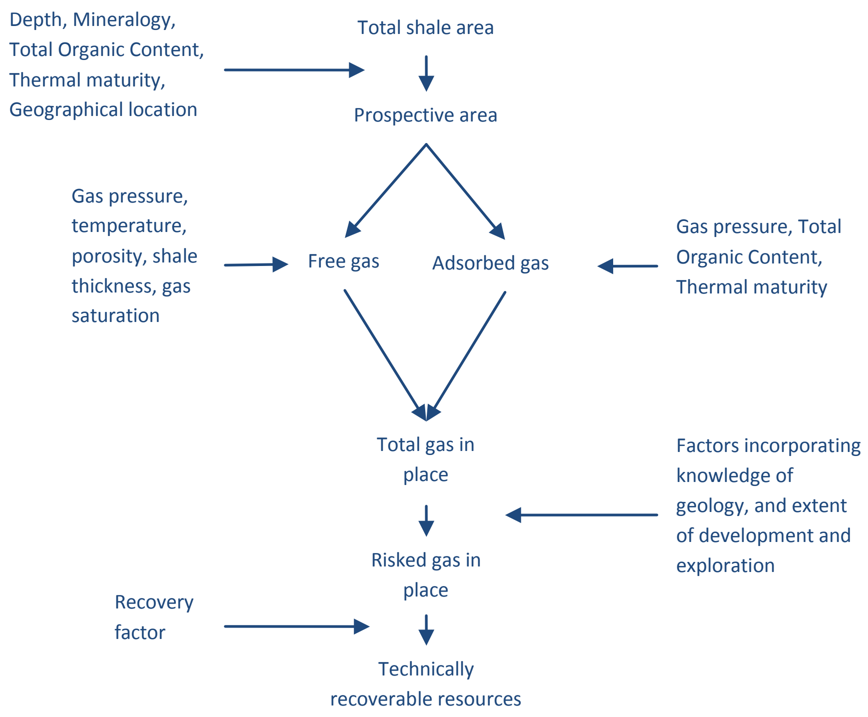
methodology other than noting that *'most credible studies'* were used. It also does not provide details of the literature referred to other than the names of the organisations that produced the estimates.

An alternative approach is followed by Medlock *et al.* [28] who indicate that they use *'peer-reviewed, scientific assessments of the properties of shales to develop technically recoverable resources'.* However, Medlock *et al.* do not specify the precise approach used and fail to cite the relevant peer reviewed sources. In addition, they note that *'A reduction of the technically recoverable shale gas resource base in areas with potential water constraints is primarily done because the cost of development has been deemed prohibitive…'*. In explaining the difference between their and ARI's estimates, Medlock *et al.* also note that the clay content of the shale can constrain recoverability. Clay-rich shales will have lower production rates and higher costs and so are excluded from their estimates of recoverable resources. Since these constraints are not employed by other sources estimating TRR, Medlock *et al.*'s resource figures may correspond more closely to ERR.

Bottom up analysis of geological parameters

This approach uses geological knowledge of the extent and characteristics of the shale rock to estimate the volume of shale gas that is present. A recovery factor is then applied to this estimate to produce an estimate of the technically recoverable (or ultimately recoverable) resources. ARI [32] employed this approach to determine the volumes of gas that exist in worldwide shales for which there was little, or no, drilling experience or production data. Figure 3-2 summarises the approach, indicating the geological parameters used at each step in the process.

Figure 3-2: Schematic representation of the steps used in the geological based approach



Source: Adapted from [32]

The first step involves determining the total areal extent of the shale being examined. This is next reduced to the 'prospective area', which, depending on estimates or determinations of various properties of the rock, describes the area of shale that is expected to contain an appreciably high concentration of gas to make development viable. The geographic location of the shale is also taken into account at this stage, with shale that is in offshore regions removed from the prospective area.

Within shale plays, natural gas can be stored either in pore spaces within the rocks ('free gas') or adsorbed[11] onto the rocks. Equations can be used to estimate the volumes of gas that are stored in these ways and these require estimates of various geological parameters such as the pressure of the gas in place and the porosity of the rocks.

Two further factors are then determined that represent the confidence of the authors in their estimates given their extent of knowledge of the geology and the prior exploration and development of the play. These factors are the 'play success probability factor', which represents the probability that suitably high flow rates will be achieved from the play to make development likely, and the 'prospective area success factor', which represents the probability that there will not be any geological complications or problems in the

[11] Adsorbed gas is gas attached to the surface of the rock.

prospective area that would reduce the volumes of gas present. For the plays in ARI's report, the play success probability factor ranged from 100% to 30% with a mean for all of the shale plays analysed of 58% while the prospective area success factor ranged from 75% to 20% with a mean of 50%. The product of these and the estimated gas in place yields an estimate of the 'risked' gas in place. Using the above mean factors of 58% and 50%, the 'risked' gas in place would therefore be 29% of the gas in place. A number of other approaches use comparable 'success factors' to reduce volumes of gas that are estimated to exist.

Finally, a recovery factor is estimated to reflect the anticipated fraction of this volume that is likely to be technically recoverable. The product of the recovery factor and the 'risked' gas in place gives an estimate of the technically recoverable resource. ARI [32] indicates that the recovery factor is established on the basis of the shale mineralogy, properties of the reservoir and the geological complexity. The values chosen typically lie in the range 20–30%, although factors of 35% and 15% are used in *'a few exceptional cases'.*

As can be seen from Figure 3-2, there are a large number of parameters which must be estimated or calculated when using geological methods to determine recoverable volumes of gas. These parameters range from the area and geographical location (onshore/offshore) of the shale rock, to the total organic content (measured as a percentage of the total weight) of the shale, to the minerals (clay/quartz etc.) contained within the shale. A number of these parameters are used at more than one stage of the process. There are also some factors, whose estimation, although depending on a number of these parameters, is largely subjective. Examples are the recovery factor and the two factors for converting the OGIP estimate into a 'risked' OGIP estimate. ARI sets out which factors have been used in an appendix; however of the eleven other sources using this approach, only three [43, 50, 53] provide figures for both TRR and OGIP from which the assumed recovery factors can be determined.

Extrapolation of production experience

This approach relies upon analysing the production experience in shales for which there is a sufficiently long history of production and then extrapolating these results to either undeveloped areas of the same shale or to new shales. There are two general methods employed. The first, commonly applied at the play level, is to estimate shale gas volumes, either OGIP or TRR, by multiplying the estimated shale play area (or mass) by an estimated yield per square area (or mass). The yield per unit area is often called the productivity and measured in mcm/km^2. For undeveloped shale play areas, the values for such calculations are typically based upon measurements or estimates from geologically similar regions (analogues) where more information is available.

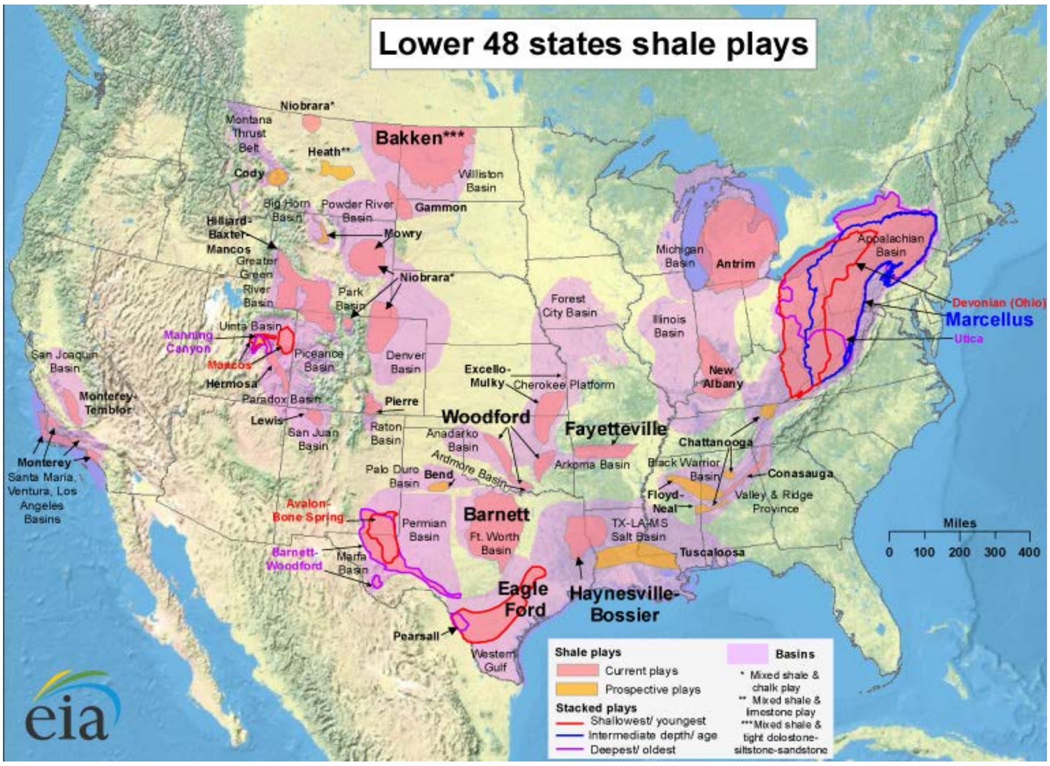
The second method differs in its complexity: the investigated area is split into more and less productive sectors, and more precise gas yields per area are determined using a greater number of parameters including the URR per well and the well spacing (no. of wells per unit area). Estimates of the URR per well require the extrapolation of production from currently producing wells with the help of decline curve analysis – discussed in more detail in Chapter 4.

Each of these two methods has been used by two reports. The first simpler method was used by Rogner [59] and the UK's Department of Energy and Climate Change ('DECC') [47]. Surprisingly, given the reliance that has been placed upon his work, Rogner appears to have used a relatively crude approach on which he provided very little information. He notes simply that: *'the ratio of the US estimates for natural gas from shale formations to the in-place shale volume was used as a guide to calculate the regional natural gas resource from fractured shale resource potentials...based on the assumption that shale oil occurrences outside the United States also contain the US gas value of 17.7 Tcf/Gt [gigatonne] of shale-in-place'*. Rogner therefore appears to have used only a single analogue to estimate worldwide shale gas resources.

DECC also used this simpler approach in order to estimate shale gas resources in the UK. More than one analogue was used with the Barnett, Antrim, and a 'more conservative' play, identified as possible analogues for the three shale plays in the UK. The choice of analogues significantly affects the resource estimates produced, with the productivity of the most productive analogue play (the Barnett at 7.6 mcm/km^2) being thirteen times greater than that of the least productive analogue play (the 'more conservative' play at 0.6 mcm/km^2).

The second approach requires substantially more information from areas that are already being developed, but is likely to be more reliable. As a result, this approach has been used by two of the main sources providing shale gas resource estimates for the United States, namely INTEK [18] for the EIA and the USGS (for example [15]). The approaches taken by the two organisations are described in more detail below and these descriptions serve to illustrate the types of issues that are raised. A map of all US shale gas plays is presented in Figure 3-3.

Figure 3-3: Map of US shale gas plays



Source: [18]

Methods used by the US Energy Information Administration

INTEK [18] undertook a review of all shales within the United States for the latest edition of the EIA's Annual Energy Outlook. INTEK sought to estimate the 'unproved discovered technically recoverable resources'[12] within 19 individual shale plays in the United States. Aggregate estimates of the proved reserves, inferred reserves[13], and undiscovered resources for the whole of the United States are provided within INTEK's report. The sum of these along with INTEK's estimates of the unproved discovered technically recoverable resources from each shale play gives an estimate for the remaining TRR for the entire United States. The total TRR can then be estimated by adding a contemporaneous estimate of cumulative

[12] Elsewhere in the report these are described as 'undeveloped technically recoverable resources'. Neither of the two definitions provided is particularly satisfactory. The first uses the term 'discovered' in a manner that differs from the SPE/PRMS definition described in Section 2.1, which would describe the figures produced by INTEK as 'undiscovered'. The second implies that proved and inferred reserves can only be in developed areas, which is not necessarily the case [78].

[13] As indicated in Section 2.2, inferred reserves are assumed to be equal to 'probable' reserves. The sum of proved and inferred reserves will therefore give an estimate of the 2P reserves.

production. The undiscovered resources are indicated by INTEK to be estimated at 1.2 Tcm in Southern California and 0.4 Tcm in the Rocky Mountain region.

For each shale play, INTEK first split the whole play area into two areas it termed the 'active area' and the 'undeveloped area'.[14] For a few plays INTEK judged the whole shale play area to be 'active' and so did not differentiate the play, but in general each of the two areas within each shale play was considered separately. Based upon a variety of technical, commercial and industrial reports, INTEK estimated the URR/well and well spacing within each area of each shale play. The product of the URR/well and well spacing with the areal extent of the area under consideration coupled with an assumed 'success factor'[15] yields an estimate the 'unproved discovered technically recoverable resources' within that particular area. The sum of the 'active' and 'undeveloped' areas finally gives the 'unproved discovered technically recoverable resources' within the whole shale play.

INTEK's success factor, a percentage that can vary between 0-100%, was assumed to depend upon three factors: whether the estimates for URR/well and the well spacing currently used were considered to be representative of what can be expected across the whole ('active' or 'undeveloped') area; how much experience there was of geological factors that can affect production; and how much gas had already been produced or added to reserves. Choice of appropriate values for the success factor appears to be relatively subjective and varies between 10% in the 'active' area of the Fayettesville shale to 100% in the 'active' areas of the Eagle-Ford and Barnett-Woodford shales. The arithmetic mean success factor across all shale plays is 49%.

Currently producing US shale gas plays are very heterogeneous, with production rates between neighbouring wells varying by a factor of three and across an entire shale play by a factor of ten [25]. A key issue for this method, therefore, is the validity of taking estimates of well spacing and the URR/well from one area and applying these to a second, potentially very different, area. It is commonly the case that some areas within the shale have significantly higher productivity and ultimate recovery than others. These are commonly referred to as 'sweet spots', and correspond with the area INTEK called the 'active' area. In addition, there also appears to be significant variation in the productivity of wells *within*

[14] Again this is not a particularly satisfactory term to use since some parts of the 'active' area have not yet been developed.

[15] INTEK refers to applying a 'recovery factor' to the product of the URR/well and well spacing. This is easily confused with the recovery factor used to estimate the TRR from the OGIP. INTEK's recovery factor more closely resembles the factor that geologists apply to estimate the risked OGIP from the total OGIP (as explained in the previous section) and so the term 'success factor' seems more appropriate to avoid confusion.

sweet spot areas, although this distinction partly depends on how sweet spots are defined [79–80].

Given this heterogeneity, it is important not to assume single values for the URR/well and well spacing across the whole area of a shale play. This is particularly relevant when extrapolating historical URR/well and well spacing estimates, since these will only be available from the areas of the shale play which have been developed first and which tend to be the most productive. Hence, they are unlikely to be representative of what will be encountered in the remainder of the shale. It was for this reason that INTEK split most shale plays into two areas. INTEK assumed a lower value for at least one of three relevant variables, namely the URR/well, well spacing or success factor in its 'undeveloped' (non-sweet spot) areas. Which variable was lower, and to what extent it was lower, depended on the shale play under consideration.

Finally, INTEK assumes that the sweet spot area is the total area leased by shale gas producers [81]. As discussed in Section 3.3, this is unlikely to be appropriate assumption.

Methods used by the US Geological Survey

As indicated above in Section 2.2, the USGS undertakes analysis of geological areas within the United States and provides estimates of the 'potential additions to reserves' for unconventional gas from those areas. While it does not provide an estimate of TRR for the whole of the United States, such an estimate can be compiled by summing:

- USGS mean estimates of the potential additions to reserves for all individual shale plays;
- total proved United States shale gas reserves;
- inferred reserves of shale gas (available from [18]);
- estimates of technically recoverable resources in undiscovered shale gas plays (also available from [18]); and
- cumulative shale gas production.

The approach taken by the USGS is described in two methodological papers [16–17], one of which is a 2010 update of the method used previously. These two methods differ slightly since the earlier method excluded any shale gas that was estimated to exist in non-sweet spot areas from the estimates of 'potential additions to reserves' that were produced. The earlier method also refers to dividing the area under investigation into 'cells' with particular drainage areas (no. of cells per unit area) rather than wells: cells and wells are essentially identical however [17]. Nevertheless, the general approach of both methods is similar: the shale play is split into individual areas, and then estimates are made of the areal extent of each area, the drainage area of wells (or cells) within those areas, and the mean URR/cell or URR/well within those areas.

In the newer method a 'success ratio' is also estimated separately for the sweet spot and non-sweet spot areas. This factor represents the percentage of wells that the USGS estimates will produce at least the minimum URR/well and modifies the product of the above parameters, tending to reduce the volume of gas estimated to be technically recoverable. The earlier method also estimated a factor similar to the success ratio but this was not used in the volumetric calculations.

The product of the success ratio (if used) and the above parameters yields an estimate of the discovered technically recoverable resources. Although not explicitly stated in its methodology papers, the USGS then removes cumulative production and an estimate of gas considered to be reserves in order to yield its estimate of the 'potential additions to reserves'.

The USGS approach differs in four important respects to the INTEK approach. First, the USGS acknowledges the considerable uncertainty in all of the above factors and uses Monte-Carlo sampling techniques to combine these uncertainties and estimate a probability distribution for the relevant variables. Second, when developing estimates such as the URR/well or the areal extent of the shale (and in estimating the uncertainty in these values), the USGS takes geological factors into account, such as the shale thickness and mineralogy. The USGS indicates that these factors should be plotted as maps, and that they can affect the assumed success ratios and/or URR/well. However, little detail is given as to how these factors are actually used. Third, the USGS splits a particular shale play into smaller 'assessment units',[16] and assesses each of these individually. It therefore differentiates between sweet spot and non-sweet spot areas on a smaller scale than INTEK. The recent USGS assessment of the Marcellus shale [15] for example split the play into three assessment units. Each of these units is divided into sweet and non-sweet spots; the USGS therefore identified six different areas within the Marcellus shale each with different sizes and productivities, while INTEK only split it into two.

Fourth, the USGS periodically updates its resource assessments for individual US shale plays or areas of the plays and produces an end-of-year summary combining all of the latest surveys it has carried out [69]. The latest resources assessments are summarised in Table 3-1. It can be seen that some areas have not been examined since 2002. One would expect

[16] An 'Assessment Unit' is defined as areas that 'encompasses fields (discovered and undiscovered) which share similar geologic traits and socio-economic factors.' [3]

that those assessments produced after 2010 would have relied upon the updated assessment method described above, but this does not appear to be the case. The USGS recently released the data [82] it used in its most recent assessment for the Marcellus shale [15]. This data consists of the ranges assumed for the parameters required to estimate potential additions to reserves, for example the mean URR/cell and indicates that the old assessment method was used. While data for the other assessments undertaken since 2010 are not available, it seems likely that the old methodology was used for all of these. As described above, the earlier assessment methodology excluded volumes of gas estimated to exist in non-sweet spot areas, and so is likely to underestimate the total play TRR [17]: this represents another important difference between the assessment results of the USGS and INTEK.

As mentioned above, the overall TRR for shale gas in the United States can be estimated by summing: a) all USGS estimates of 'potential additions to reserves'; b) proved shale gas reserves; c) inferred reserves of shale gas; d) estimates of technically recoverable resources in undiscovered shale gas plays; and e) cumulative shale gas production. It is important to remember however, that within each shale play, the figures to be added must be contemporaneous with the date on which the USGS carried out its assessment. One cannot, for example, simply add current estimates of proved reserves to the USGS figures, since volumes of gas that were not considered reserves when the USGS made its assessment but are now included as reserves would have moved from the USGS 'potential additions to reserves' category into the reserves category. Such volumes should not therefore be included in both categories or double counting will result. A similar situation exists with cumulative production.

A detailed breakdown of proved reserve figures is only available from 2007, and inferred (probable) reserves provided only as a single figure; a rigorous assessment of the USGS estimate of TRR within each shale play is therefore impossible.

In the early 2000s, the potential of shale gas production was not fully realised (as can be seen from the low level of resource estimates in Figure 2-5) and so the majority of shale plays assessed at that time were unlikely to have contained any proved reserves, with the exception of the Barnett and Antrim Shales. Therefore, for those shales which were assessed prior to 2007 we assume that proved reserves are zero, except in the Barnett and Antrim shales. For the Barnett Shale historic estimates of proved reserves are available,[17] however no data is available for historic proved reserves in the Antrim Shale and so we use the earliest data available from 2007. The fifth column of Table 3-1 therefore gives an

[17] See: [83]

approximation of contemporaneous proved shale gas reserves, while contemporaneous figures for cumulative production are presented in column six.

Summing the mean estimates of the 'potential additions to reserves', proved reserves and cumulative production for each shale play leads to an estimate of 11 Tcm for the total technically recoverable resource in these plays. To obtain an estimate for the total technically recoverable shale gas resource in the United States, we add in estimates of undiscovered resources (1.6 Tcm) and inferred reserves (0.56 Tcm) both taken from [18]. This leads to an estimate of **13.1 Tcm**,[18] which compares to a mean estimate of 23.5 Tcm and a range of 8.0 – 47.4 Tcm from the review of studies presented in Chapter 2. However, since the earlier USGS methodology excluded non-sweet spots, which are now expected to contain significant volumes of shale gas, it may have underestimated the potential additions to reserves in those plays.

[18] Some, but not all, double counting is eliminated by this process.

Table 3-1: USGS estimates of shale gas resource in the United States

Report	Assessment Date	Major shale plays analysed	Mean estimate provided (Tcm)	Proved reserves at time of assessment*	Cumulative production at time of assessment**
Coleman *et al.* [15]	2011	Marcellus shale	2.39	0.13	0.01
Dubiel *et al.* [14]	2010	Haynesville and Eagle-Ford	3.62	0.31	0.05
Higley *et al.* [61]	2010	Woodford shale	0.70	0.18	0.03
Houseknecht *et al.* [62]	2010	Fayetteville and Woodford-Caney	0.76	0.25	0.05
Schenk *et al.* [63]	2007	Barnett-Woodford	0.99	0	0
Swezey *et al.* [64]	2007	New Albany	0.11	0	0
Swezey *et al.* [65]	2004	Antrim	0.21	0.09	0.04
Pollastro *et al.* [66]	2003	Barnett	0.75	0.10	0.02
Higley *et al.* [67]	2002	Niobrara	0.03	0	0
Milici *et al.* [68]	2002	Devonian (Ohio) shale	0.11	0	0.07
Total			**9.67**	**1.07**	**0.27**

Notes: The USGS analyses 'Assessment Units'. The borders of the shale plays and assessment units therefore do not always coincide. We have summarised the major shale plays analysed by the various reports as these are generally better known. Most reserve figures are only available at a state level and so some judgement is required to assign these to the shale plays.

* Source: EIA [83-84]

** Source: Lippman Consulting (taken from [85-86])

Box 3: Comparison with conventional gas resource estimation methods

A detailed description of the various methods for estimating the technically or ultimately recoverable resources for conventional resources, accompanied by a comparison of results, is given in Sorrell *et al.* [11]. Several of these methods use non-linear regression to fit curves to historic data on production or discoveries for aggregate regions. Such curves typically trend to an asymptote, which is interpreted as the ultimately recoverable resources for that region. More sophisticated methods rely upon data from individual fields.

Such methods are not currently used for unconventional deposits and appear unlikely to be appropriate for a number of reasons. First, the conventional approaches are based upon implicit or explicit assumptions regarding the size distribution of conventional gas fields and the sequence in which these fields are discovered and produced (i.e., with the largest being found first). These assumptions are not applicable to unconventional deposits since these are not located in discrete fields. Second, sufficiently long time series data on regional production and discoveries is currently unavailable for unconventional resources, even within the United States. Third, continuous drilling is necessary to maintain production levels within a shale play [87], so the regional production history is more dependent upon the economic and political factors affecting drilling activity than on any geological features of the resource. Hence, procedures relying on plotting cumulative production against time are unlikely to provide any useful information. Finally, shale geology is so variable that aggregating individual shale play production or exploration data that could be used to estimate the recoverable resources to a regional level is, at least at this stage in the development of the resource, neither informative nor useful.

3.3 Methodological robustness of each method

This section, identifies some of the strengths and weaknesses of the different methods, attempts to explain why differences exist between estimates, and indicates which procedures are likely to be most robust.

Literature review/adaptation of existing literature

Studies relying upon literature reviews draw on information from a variety of sources and hence a variety of methods of resource estimation, and so remove some of the uncertainty over the choice of method. They also appear more likely to quantitatively estimate the uncertainty in their resource figure. For example on the basis of the variation in resource estimates provided by sources for the United States, Mohr and Evans [39] indicate that the 'best' estimate of URR for shale gas in the United States is 17.7 Tcm with a 'high' value of

35.9 Tcm and a 'low' value of 9.3 Tcm. The authors do not, however, provide a range of uncertainty for any countries outside North America.

On the other hand, reports relying on literature reviews are potentially open to subjectivity over which sources are to be included and which should be relied on more heavily. The extent to which and reasons for which certain sources have been favoured over others is rarely made clear – although Medlock *et al.* [28] do indicate that non-technical publications such as investor relation reports are avoided. It is also not always clear how the quoted literature has been used. MIT [8] for example, cites ICF, USGS and the National Petroleum Council ('NPC') as the sources used for its unconventional gas estimates. The mean value chosen by MIT for US shale gas corresponds to the values used by ICF; however it is unclear how MIT's estimates for its P10 and P90 volumes of shale gas rely upon the USGS and NPC figures.

Bottom up analysis of geological parameters

The geological approach employs well-known and well-understood equations to estimate the volumes of free and adsorbed gas in place. A number of problems exist however.

The first and perhaps the most important is the inherent subjectivity in choosing the recovery factor to apply to the estimated gas in place. It was for this reason that the USGS chose not to use this approach stating: *'the estimation of an overall recovery factor must sometimes be quite qualitative'*. ARI [32] attempted to remove some of the subjectivity in its estimates of recovery factors, which lay between 20-30% in most circumstances, by linking this to the mineralogy of the sources rocks; however recovery factors of 15 to 40% have been used by other authors [27, 48, 70], while Strickland *et al.* [80] report that some recoveries can be as low as 1-2%. When the volumes of gas in place are so large, this corresponds to a huge range of uncertainty in the technically recoverable resources.

An additional problem relates to the estimation of the geological variables required for this method. It is important to remember that data may only be available for a subset of these, and for unexplored shale plays such estimates must necessarily have large confidence bounds. Hubbert [88] remarked that for conventional petroleum resource estimates: *'it is easy to show that no geological information exists other than that provided by drilling...that has a range of uncertainty of less than several orders of magnitude.'* Even when exploratory drilling has taken place, the range of uncertainty may still be wide. For example, it is often difficult to estimate the gas saturation[19] from well-log data, a key parameter in the estimation of the gas in place [89-90].

A third problem relates to the issue of 'sweet spots'. As mentioned above, there is significant heterogeneity between sweet spots and non-sweet spots. Simply extrapolating geological values from certain areas within the sweet spot across the entire extent of the shale is likely to overestimate the resource potential, and segregation of the shale play area is necessary to avoid this. ARI's concept of 'prospective area' indicates an attempt to disregard areas of shale that are likely less productive. The next step would be to delineate the prospective area into sweet spot and non-sweet spot sectors, but ARI was unable to do this.[20] The frequency and extent of sweet-spots and the degree of variation between sweet-spots and other areas remains uncertain, even in comparatively well developed shales. The new USGS method employed a probabilistic approach to estimate the range of the split between sweet spots and non-sweet spots within areas of each shale play: this procedure will reduce some of the error that arises through ignoring sweet spots altogether.

A fourth point is that this approach does not depend particularly upon prior production experience. Drilling is the only reliable means of assessing the extent and volumes of shale gas that exists as can be seen by the large number of wells that have been drilled outside the sweet spot areas within the United States. This shows that the productivity of these areas can vary enormously and, although displaying some correlation with parameters such as the shale thickness, is not really known until drilling is well underway [79, 91].

The final and most important problem is the absence of a rigorous approach to uncertainty. While some reports mention the uncertainty in values in passing or give a range in final resource estimates, no reports placed in this category provided a thorough description of the uncertainties that had been analysed or present their results in the form of a probability distribution. There is no reason, except potentially because of an absence of relevant data, why the uncertainties in individual geological parameters (particularly those used more than once or which are especially uncertain such as the areal extent of the shale), cannot be estimated, stated and accounted for. Use of statistical distributions can be simple, but nevertheless effective: the USGS, for example, mainly uses triangular distributions combined through a simple random sampling technique.

[19] The gas saturation is the fraction of the porosity of the shales filled with gas rather than water.

[20] ARI states *'The prospective area will contain a series of shale gas quality areas, typically including a geologically favourable, high resource concentration "core area" and a series of lower quality and lower resource concentration extension areas. However, the further delineation of the prospective area was beyond the scope of this initial resource assessment study.'*

Extrapolation of production experience

This approach avoids some of the above problems but unfortunately introduces some more, one of which is currently somewhat controversial. It is first interesting to note that the only source providing a detailed methodology, the USGS, chose to employ this approach.

The key additional problem introduced regards the methods for estimating the URR from individual wells. As explained in detail in Chapter 4 these methods rely upon modelling the anticipated decline in the rate of production from individual wells. Different choices are available for the 'shape' and rate of future production decline, and the limited historical experience at present does not constrain these choices especially well – with different choices potentially leading to very different estimates of the URR. As explained in Chapter 4 there are concerns that current practice may be overestimating the URR for individual wells. To the extent that these form the basis of regional resource estimates, these too could be overestimated.

An additional problem that applies to the simple analogy-based approach used by DECC [47] and Rogner [59] concerns which analogue to choose. The choice of an analogue is extremely important: as noted DECC's choices of analogues varied by a factor of ten. The USGS suggested using a probabilistic approach with more than one analogue to reduce this problem [91], which appears to be a sensible approach given the uncertainties that exist.

A further problem, given both the complexity and heterogeneity of the geological determinants and the absence of a long history of production data, is the validity of the assumptions made for the productivity of areas outside those currently being produced. As mentioned in Section 3.2, historic production has focused upon sweet-spots and upon the most productive areas within those sweet-spots. Extrapolating a mean URR/well from this area to the whole of the sweet spot could potentially overestimate the resource potential. If these estimates are then extended across the entire shale play, the resource potential of the region could be greatly overestimated.

The USGS attempted to mitigate this problem by mapping a range of geological factors and using these to estimate the possible productivities outside the area currently being produced, although it has not, in the assessments it has performed so far, attempted to estimate the productivity of non-sweet spot areas. Nevertheless, its approach is relatively transparent and has the advantage that uncertainties are explicitly accounted for. In contrast, INTEK does not provide any detail on how it estimates either the URR/well or the well spacing in undeveloped or non-sweet spot areas, and there appears to be little empirical basis for the values chosen.

It is clear, therefore, that careful delineation of the shale play is necessary to avoid overestimating productivity in undeveloped areas, but delineation is itself challenging. This is particularly relevant when splitting the shale play into sweet spot and non-sweet spot areas. Given the heterogeneity even within sweet-spots, it is preferable to define and isolate the shale into an even greater number of areas of differing productivity: a procedure used by the USGS through the differentiation of shale plays into smaller assessment units.

The USGS relies upon geological assessments to classify sweet spots, while INTEK uses the area leased by companies as a proxy. While the latter is a simpler and cheaper approach, it is likely to over-simplify the problem for a number of reasons. Firstly, the acreage details used appear to be significantly out of date. Within the Marcellus shale, for example, XTO Energy, purchased by ExxonMobil in 2009 when it held around 280,000 acres, is listed as holding 150,000 acres. Similarly, Talisman Energy Inc. is reported to hold 640,000 acres yet in a May 2010 investor report indicates that it held around 218,000 acres [92].

A second problem regarding INTEK's choice of sweet spots areas is its reliance upon a report published in 2008 [81]. Since only a limited number of wells had been drilled by that time (e.g. only 234 in Pennsylvania), the productivity of the leased areas was not known with any confidence. [93]. There is therefore no real justification why the area leased in mid-2008 should correspond to the sweet-spot area. Furthermore, as mentioned above, given the heterogeneity of sweet-spot areas, assuming current productivity will likely provide an overestimate for the remainder of the sweet spot area.

One final drawback with the INTEK report is its reliance upon highly subjective estimates of the 'success factor' to translate historical production experience into an estimate of recoverable resources for the whole shale. The updated USGS methodology includes a comparable 'success ratio' which reflects the percentage of wells that is estimated will produce at least the minimum URR. The updated USGS methodology, which requires estimating the success ratio, was not actually used for any of the assessments presented in Table 3-1. Nevertheless, the new USGS methodology estimates success ratios at a lower level of spatial aggregation, basing its assumptions to a greater extent on the results from drilling activity and uses probability distributions to reflect the associated uncertainties. Hence, it should have lower degree of subjectivity.

A comparison of the two approaches in their assessments of the Marcellus Shale play is given in Box 4.

Box 4: Comparison of Marcellus Shale play assessments

Recently released data [82] from the USGS allows one to attempt a 'like-with-like' comparison between the assessments carried out by the USGS [16] and INTEK [19] of the Marcellus Shale. The first point to note is that the USGS estimate is of 'potential additions to reserves' while INTEK's estimate is of 'unproved discovered technically recoverable resources'. Despite these different names, both exclude any volumes of proved reserves from their estimates, and we assume both exclude 'inferred reserves'. The two estimates are therefore of identical terms.

We include below only the mean estimates of the data provided USGS: reproducing the estimates provided in [16] would require a rigorous handling of the ranges it provides. There are some errors introduced by this but the overall difference between the calculated value and quoted figure provided by the USGS in [16] is only 0.4%. These three assessment units cover all of the area in which production is currently occurring in the Marcellus shale, although some wells also produce from overlying and underlying shales. [18] indicated that the USGS concept of 'cells' is closely related to 'wells' and so we simply use the term wells and well spacing below to avoid confusion.

There are two major differences that can be seen in the table below that result in the difference between the 'headline' figures of 2.4 Tcm by the USGS and 11.6 Tcm by INTEK. First, the USGS excludes shale gas in non-sweet spot areas, which INTEK indicates makes up 57% its estimate. A closer like-with-like comparison would therefore look only at the resources from 'sweet spot' areas. INTEK's resource estimate within its sweet spot area is still 110% larger than USGS's however, and so the second major difference can be seen to be the values used for URR/well. INTEK's URR/well is over three times the productivity within the Interior assessment unit, the most productive of USGS's assessment units. In fact, INTEK's non-sweet spot productivity is equivalent to the mean productivity within the sweet spot area of the USGS's most productive assessment unit. Countering this to an extent is USGS's larger overall sweet spot area, which is around 90% greater than that used by INTEK. The two non-sweet spot areas are almost identical, indicating that the USGS considers the areal extent of the Marcellus shale to be around 10% larger than INTEK.

	INTEK	**USGS**			
Assessment unit		Foldbelt	Interior	Western Margin	**Total**
Sweet spot area					
Area (km^2)	**27,511**	2,469	42,840	7,151	**52,460**
Well spacing (wells/km^2)	3.1	1.7	1.7	2.1	
URR/well (mcm/well)	99.2	5.9	32.6	3.7	
Success factor	60%	Not used			
Calculated gas volume (Tcm)	**5.06**	0.024	2.315	0.056	**2.395**
Quoted gas volume (Tcm)	**5.06**	0.022	2.305	0.058	**2.385**
Non-sweet spot area					
Area (km^2)	**218,261**	46,903	74,114	96,043	**217,060**
Well spacing (wells/km^2)	3.1	Not assessed			
URR/well (mcm/well)	32.6				
Success factor	30%				
Calculated gas volume (Tcm)	**6.59**	Not assessed			
Quoted gas volume (Tcm)	**6.59**				

3.4 Impact of technology on resource estimates

The studies reviewed above have focused upon estimating the volume of shale gas that could be recovered using currently available technology. As the USGS comments:

> *'….The USGS oil and gas estimates are of technically recoverable resources as opposed to in-place resources. Technological and economic assumptions are conservative and limited, in that the production data used for calculating well URRs are contemporary to the time of the assessment… large improvements in technology or increasing petroleum prices could possibly increase recovery factor substantially in the future. Because this new methodology is tied to contemporary well-production data, such improved recovery factors are not used as part of this assessment methodology'*

As indicated in Section 2.2 assessment methods that explicitly allow for future technological advances are likely to lead to substantially larger estimates of recoverable resources. Only three reports that attempt to quantify the effects of future technology development have been identified, namely: a 2004 report by Kuuskraa [58], a paper by the US National Petroleum Council [94] and a number of the EIA AEOs [25]. In each case, technological progress is represented by annual percentage increases in the URR/well.[21]

This percentage, extrapolated over a given time frame and multiplied by a contemporary estimate of TRR will yield an estimate of the URR. For example if TRR in a particular region is estimated at 2.8 Tcm and technological progress is estimated to increase URR/well by 30%, then all else being equal, the URR for that region will be 3.7 Tcm.

Table 3-2 illustrates the assumed annual improvement in recovery and the implied overall increase over a 30-year time period. The mean of all 'medium' estimates of the increase in TRR that is estimated will occur from future technological progress is 36% over a 30 year period (this mean has been weighted by the number of reports giving each technological progress and so takes into account that more than one AEO is included in the first and third rows).

The EIA [25] from 2000-2009 identified three technologies that it expected to contribute to a greater URR/well for shale gas (and the other unconventional technologies but at different rates). These were*: 'geology technology modelling and matching'*, *'more effective, lower damage well completion and stimulation technology'*, and *'advanced well completion technologies, such as cavitation, horizontal drilling, and multi-lateral wells'*. The first two of

[21] Other metrics for measuring the impact of technological progress on recoverable volumes of shale gas can also be used. For example the usual metric for estimating impacts of technology on conventional oil and gas recovery is by increases in the recovery factor [95].

these contribute an annual increase in URR/well and the third an aggregate increase, presumably resulting from the switching from vertical to these new drilling technologies, over the timescale of the AEOs, generally around 20–25 years. It can be seen that different AEOs assumed slightly different rates of progress.

We assume that these technologies are complementary and so the figures indicated in Table 3-2 are the sum of the contribution from each, converted into an annual increase and the total increase in the 30-year period.

The latest two AEOs (2010 and 2011) use a slightly different approach and indicate that the *'pace at which technology performance improves and the probability that the technology project will meet the program goals'* for URR for shale gas was 8% for 'developing' resources and 7% for 'undiscovered' resources. It is not clear what these terms mean or how these percentages are actually used however as very little explanation is provided, they are therefore not include in Table 3-2.

Two of the three technologies (stimulation[22] and horizontal drilling) mentioned above are indeed the technologies that have spurred the recent increase in TRR estimates. The rate at which they would increase URR/well has been vastly underestimated however. ARI [79] indicates that the URR/well within the Barnett Shale between 1985 and 1990, averaged around 11.3-14.1 mcm/well but in 2007-2008 had increased to around 65.2 mcm/well. This corresponds to around a 410% increase in URR/well in about a 20 year period, and has occurred primarily through the more widespread and improved use of horizontal drilling and stimulation.

The fastest rate of increase in URR/well anticipated in Table 3-2, which includes increases from switching from vertical to horizontal wells and the use of hydraulic fracturing, implies an increase of only 50% over a comparable timeframe. This significant underestimation of the role of technological progress in the past demonstrates the difficulty in estimating future technological progress, even when using a wide range of potential values.

Nevertheless, it is important to note that it was not the introduction of 'new' technologies i.e. technologies that had not been employed elsewhere and whose potential was unknown, but the adaptation and utilisation of existing technologies that led to the large increases seen in the URR/well. The potential for the utilisation of entirely 'new' technologies for shale gas recovery has not been discussed in any of the EIA AEOs. This suggests that it is the existing technologies of stimulation and horizontal drilling that will continue to be used in

[22] Stimulation, also known as hydraulic fracturing, involves *'"pumping fluids" consisting primarily of water and sand...injected under high pressure into the producing formation, creating fissures that allow resources to move freely from rock pores where it is trapped.'* [96]

the future and that increases in URR/well will be driven by their more widespread usage and improvements in how they are used. New technological breakthroughs can never be ruled out however.

These two technologies, stimulation and horizontal drilling, are now much more widely used than in 2000, when the estimates of technological progress in URR/well were first given by the EIA. It therefore seems likely that there is less potential for a step increase through switching from vertical wells without stimulation to horizontal wells with stimulation, in addition to there now being a better understanding of the current and future potential of these technologies. There has also been a significant body of work analysing the geology of individual shale plays. One would therefore expect shale geology to be now also much better understood and hence the scope for future improvements in URR/well to be better appreciated. These two factors suggest that such a step change in URR/well as witnessed between 1985 and present is less likely to occur again in the future.

However, another way to look at the role of technology is by examining the influence of changes in the shale gas recovery factors. Even a very small increase in average recovery factors can have very significant impacts on estimated global recoverable volumes of shale gas. For example using ARI's global estimate of shale gas OGIP of around 708.2 Tcm [32], a 1% increase in recovery factors globally would lead to an increase in global URR of 7.1 Tcm – over twice the global production of all natural gas in 2010 [73].

In conclusion, the ranges of technological progress suggested by literature as presented in Table 3-2 are likely to represent a better approximation of the role of future technological progress than they have previously. However, the significant impact that even a small improvement in technology can have on the URR and the possibility of major future technological breakthroughs, means that, in principle, estimates of URR will always be more uncertain than estimates of TRR. Estimates of future technological progress must therefore be interpreted with considerable caution.

Table 3-2: Assumed rates of technological progress in URR/well from various sources

Source	Date	Annual increase			Implied 30 year increase		
		Low	Medium	High	Low	Medium	High
EIA AEO	2004-2009	0.3%	1.3%	2.0%	8%	49%	80%
	2003	0.4%	0.5%	0.6%	13%	16%	19%
	2001-2002	0.6%	0.8%	1.2%	19%	25%	43%
	2000	0.3%	0.5%	1.1%	9%	16%	41%
Kuuskraa	2004		0.8%			27%	
NPC	2003 (updated in 2007)	0.2%	0.9%	1.5%	7%	30%	56%
Mean		*0.3%*	*1.0%*	*1.5%*	*9.6%*	*36.1%*	*56.3%*

Note: the mean figures have been weighted by the numbers of reports providing each percentage.
Sources: [25, 58, 94]

3.5 Summary

Nearly all of the sources examined acknowledge that the estimates they provided are liable to change. Despite this, the majority present their results as single figures rather than a range (see for example Figure 2-7 to 2-9). Given the limited production experience with shale gas, the limitations of the resource assessment methodologies, the level of uncertainty associated with many of the relevant variables, the high degree of subjectivity involved and the huge changes that have occurred in US estimates over the past few years, this greatly overemphasises the certainty with which the estimates should be interpreted.

The table below summarises some of the advantages and disadvantages of the two main resource assessment methodologies. The choice between them will depend upon the extent of development of the region, the level of access to the relevant data, and the human and financial resources available. While a high-level of uncertainty is inevitable at this stage of the development of the resource, this can be addressed, or at least mitigated, through the use of probabilistic methods. The relative absence of such methods is the primary weakness of the available literature.

Table 3-3: Advantages and disadvantages of geological and extrapolation approaches to estimating shale gas resources

Bottom up analysis of geological parameters		Extrapolation of production experience	
Advantages	Disadvantages	Advantages	Disadvantages
Robust and well established geological approach	Limited data and wide range of uncertainty in many of the geological parameters	No need to assume a recovery factor	Decline rate problem for URR/well
Reduces emphasis on the use of analogues	Difficulties in delineating sweet spot areas		Difficulties in delineating sweet spot areas
	Subjectivity in choice of recovery factor(s)		Subjectivity in choice of key variables such as 'success factor'
	Not directly based on actual drilling data		Estimation of productivity in undeveloped areas
			Risk of using inappropriate analogues

Although there are drawbacks to each individual approach as set out above, one report within each of the main approaches can be identified as being preferable. Within the bottom up analysis of geological parameters category, ARI's [32] report is not only the most ambitious in scope but also provides the most detailed description of the methods used. It also attempts to address some of the general disadvantages of the approach mentioned above. One criticism, however, is its lack of handling of uncertainty.

Within the extrapolation category, the INTEK report is widely cited and influential, but has a number of important limitations, including: the inaccurate delineation of sweet-spot areas; the subjective choice of 'success factors'; the reliance upon out-of-date information; and the inadequate treatment of uncertainty. The USGS approach is significantly more transparent and robust, but there are difficulties in using the available USGS literature to estimate the overall US TRR.

All of the USGS assessments were undertaken using a methodology that excluded resources contained within non-sweet spot areas. The absence of suitably disaggregated reserve and production data also creates the risk of double counting. These two effects could however potentially act in opposite directions, the first leading to an underestimate and the second to an overestimate of recoverable resources. The most commendable feature of the USGS approach is the explicit treatment of uncertainty, which is one reason why the results may be considered more reliable than those from INTEK. Furthermore, reliability should improve once updates using the new USGS methodology are undertaken for the shale plays that have not been assessed for some time.

One major drawback of both the geological and extrapolation methods are their sensitivity to a single parameter, namely the recovery factor with the geological approach and the assumed functional form for the production decline curve with the extrapolation approach (see Chapter 4). Both of these parameters are poorly understood with regard to shale gas production and remain controversial. It is generally accepted that estimation of the recovery factor is challenging, but little progress appears to have been made regarding its estimation in shale areas, even when the geology is relatively well understood. The controversy regarding estimation of the URR/well is more recent and the reasons behind the differing assumptions used by reporting organisations are not well understood. It is for this reason that Chapter 4 below examines the issue in more detail and attempts to find common ground between the polarised views. In principle, the reliability of the extrapolation method should improve as production experience increases. Hence, we would expect approaches based upon actual production experience to provide more reliable resource estimates in the medium term. At present, however, the level of uncertainty from these methods appears to be comparable to that from geological methods. As recommended by [89], future studies that seek to derive mean estimates of the TRR for a region, should use as many different approaches as possible.

Given these multiple limitations, it essential to address and report on the level of uncertainty in the estimates whichever approach is adopted. The failure of the majority of the existing literature to do this is a major limitation. To date, only the USGS has handled uncertainty in a rigorous manner, but there is no reason why other studies could not do so.

4. Decline curve analysis and the estimation of recoverable resources

Production from shale gas wells declines continuously and rapidly within a month or two of initial production (IP). Estimating the future rate of production decline is therefore central to both forecasting future production and estimating the URR of the well – a key determinant of profitability. Appropriate methodologies for forecasting future decline rates are therefore needed to develop robust estimates of these two variables.

Such methodologies go under the heading of *decline curve analysis* (DCA) and are well established and widely used. However, the appropriateness of specific methodologies for shale gas plays has been questioned, with suggestions that future decline rates have been underestimated and both well longevity and ultimate recovery (URR) overestimated [97–98]. These individual well URR estimates form a key input into methodologies for estimating the regional URR of shale gas (Section 3). Hence, if the URR/well is being overestimated, there is a risk that the regional URR will be overestimated as well. However, other commentators contest this interpretation and point to the impressive recent history of shale gas production as evidence that future estimates are realistic [99]. While the roots of this disagreement lie in the technical assumptions underpinning decline curve analysis, the economic importance of shale gas has led to a very public and politicised debate [98–101].

The following describes the methodology of decline curve analysis and discusses the implications of decline rate assumptions for estimates of URR. The discussion focuses upon recent experience in the United States, when the production experience with shale gas is relatively advanced and where the methodology of decline curve analysis has been a particular focus of dispute.

4.1 Decline rate methodologies

Production decline from oil wells was first modelled by Arnold and Anderson [102] and subsequently by Cutler [103] and Larkey [104] among others. Contemporary decline curve analysis has its roots in Arps [105] who synthesised and elaborated a group of techniques now commonly referred to as Decline Curve Analysis (DCA). DCA typically involves fitting a curve to a time series of monthly or annual production from a well or field and extrapolating this curve into the future to forecast production rates and ultimate recovery. Arps identified two main functional forms for these curves: exponential and hyperbolic. More advanced formulations of DCA equations exist [106–107] with some being explicitly developed for the analysis of tight gas and shale gas reservoirs [108–109]. However, there is an ongoing debate about the appropriateness of different functional forms for simulating production decline from shale gas wells.

Exponential production decline takes the form

$$q(t) = q_i e^{-Dt}$$

4-1

Where $q(t)$ is the rate of production at time t, q_i is the initial rate of production at t=0 and D is a constant reflecting the decline rate ($D \geq 0$). The corresponding equation for hyperbolic decline is:

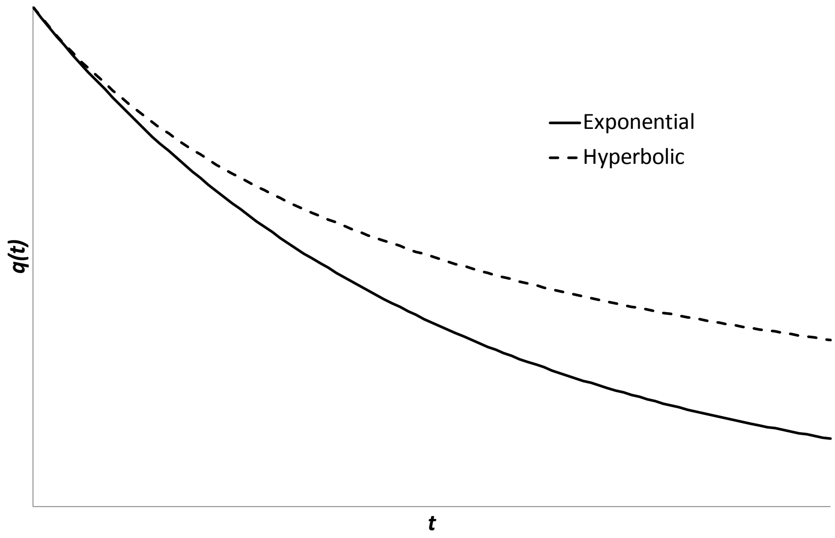
$$q(t) = q_i \frac{1}{(1 + bD_i t)^{1/b}}$$

4-2

Where D_i is the initial decline rate (t=0) and b is a constant, commonly termed the Arps decline constant which typically (but not always) lies between 0 and 1.0 [110]. The appropriate value of this constant is often the focus of dispute in decline curve analysis, as we discuss below.

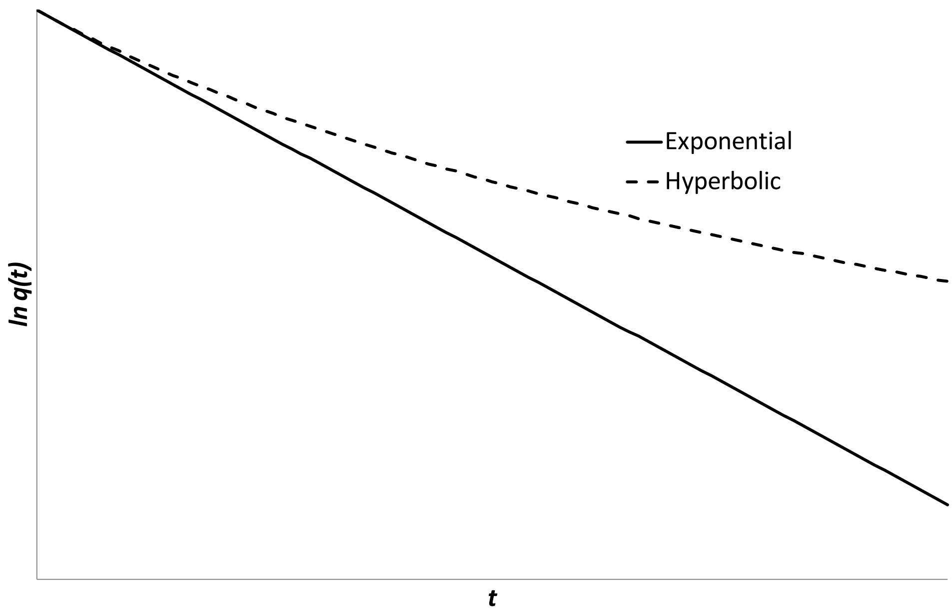
These two functional forms are illustrated in Figure 4-1. For two curves with the same initial production rate, and the same initial decline rate, the hyperbolic curve flattens earlier, maintaining a greater production rate for any given time. The area under the decline curve, from when production begins to when it finally ends represents the ultimately recoverable resource from the well.

Figure 4-1: Exponential and hyperbolic decline curves with equal initial production and decline rate



The exponential decline curve exhibits a <u>constant</u> rate of decline, *D* (i.e. the percentage change in production between time *t* and time t_{+1} is constant), and a plot of the natural log of production against time takes the form of a straight line (Figure 4-2). In contrast, the hyperbolic decline curve exhibits a <u>reducing</u> decline rate over time, so a plot of the natural log of production against time takes the form of a curve (Figure 4-2). The constant *b* represents the rate with which that decline rate reduces.

Figure 4-2: Semi-log plot of exponential and hyperbolic decline curves



While originally applied to oil production, decline curves are now commonly applied to gas fields, including shale gas. However, given the relatively recent nature of most shale gas plays, the historical evidence with which to estimate decline curves is relatively limited. The level of uncertainty may be expected to increase with the time period over which curves are extrapolated, but to estimate the URR/well, extrapolation over long time periods is required. In addition, the rapid technical developments over the past few years are likely to have affected the pattern and rate of production decline – so newer wells may not necessarily behave in the same fashion as older wells, even when the geology is similar. These factors have fuelled the debate regarding the appropriate choice and use of decline curves in shale gas areas [111-112].

Whilst the exponential decline curve is simpler, the hyperbolic curve is often found to provide a more accurate model of conventional oil and gas fields, since the rate of production decline typically slows rather than remaining constant. Production from conventional gas wells typically declines by 25% to 40% per year in the early stages [113], but production from shale gas wells declines even faster –for example, by as much as 63% to 85% per year [114]. But rather than focusing on the initial rate of decline, which is apparent after only a few months of production, the contentious question is how quickly and by how much will these decline rates reduce?

The debate has sometimes been characterised as an argument between hyperbolic and exponential decline [100]. However, exponential decline can be viewed as a special case of hyperbolic decline where $b=0$. We may therefore recast the debate as 'what is the appropriate value of b?' Figure 4-3 illustrates the change in hyperbolic decline as b varies between 0.01 and 0.99.

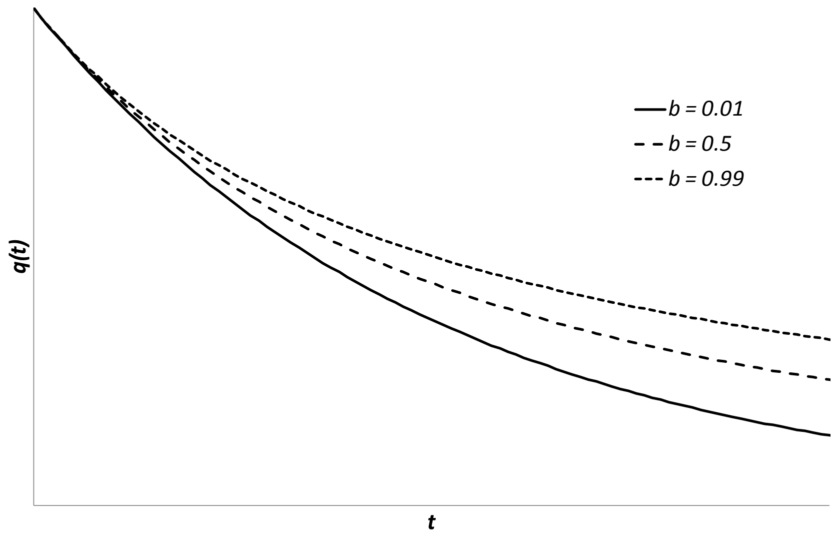
The theoretical basis for a hyperbolic decline curve assumes 'boundary-dominated flow' – where the influence of the reservoir boundaries affects the flow rate behaviour. In these circumstances, b is normally found to be between 0 and 1. However, shale gas and other unconventional gas resources exhibit more 'transient' or heterogeneous flow rates[23] and it is possible to fit curves with b constants greater than 1. To correct for the anomaly that hyperbolic decline suggests infinite production, a point of economic truncation must be assumed, where the value of produced gas drops below some assumed cost of operation. The well is then assumed to be no longer profitable, and is 'shut-in'. Such calculations require assumptions about the capital and operating cost of the well, the expected price of gas over the well lifetime and the period of time over which these costs should be amortized. Some estimates, based on a gas price of $5/ thousand cubic feet, suggest that

[23] Transient or heterogeneous flow is defined as a changing flow rate over time. In the context of shale gas this means that the flow rate is more volatile than boundary-dominated flow rates, with the potential rate of change being more dramatic.

wells in the Barnett shale are no longer profitable when producing below one million cubic feet per month[24] [98].

Evidence suggests that shale gas wells are likely to be closed down after relatively short periods of production. In an analysis of well data from the Barnett shale between 2001 and 2008, Sutton *et al.* [115] found that 10% of the horizontal wells used to produce shale gas were shut-in within 40 months of initial production. This compares to vertical wells in the same region which took over 70 months to lose the same percentage of producing wells. The difference in expected longevity between horizontal and vertical wells is a function, amongst other things, of the decline rate and the cost of well construction and operation. The implications therefore, are that using vertical well decline rates to estimate horizontal well behaviour will likely overestimate future well longevity. However, some authors have suggested that shale gas wells have been maintained past this economically rational point in order to avoid downgrading company reserve estimates [97–98].

Figure 4-3: Variation of hyperbolic decline with the value of *b*



Geologists typically estimate decline curves for wells or groups of wells with the help of non-linear regression techniques [116]. However, this form of curve fitting may have limited accuracy if only short periods of historical data are available. A key difficulty is that curves with different functional forms and/or parameter values can fit short periods of data comparably well but lead to substantially different estimates of the URR. In these circumstances, an alternative is to base the choice of curve and parameters on data from 'analogues' – that is, wells with a longer production history that are in areas with similar geological characteristics. The guidelines on what may be considered an appropriate analogue are now well defined [117–118]. Nevertheless, some commentators argue that

[24] The method of calculation of this figure and assumptions are not given.

resource estimates are frequently based upon inappropriate analogues [117]. The considerable variability in decline rates between different shale gas areas highlights the potential error associated with using inappropriate analogues [119]. This variability also affects the minimum gas price needed to support gas production in different shale gas areas. For example, between 2008 and 2009 a shale gas price of $4/Mcf would support production in the Barnett and Fayetteville shales, while a price of $6/Mcf feet would be required in the other areas [119].

Finally, analytical models, or their combination in 'hybrid' methodologies, provide an alternative route to derive the *b* constant [120-121]. Decline curves have traditionally been an empirical technique in which future estimates are derived by extrapolating historical data. These curves may better reflect the later stages of shale gas well production, the so called boundary-dominated flow [120] (see above). Newer analytical models seek to derive flow characteristics from horizontal, fractured wells through computer simulations, which model the shape, pressure and characteristics of these wells [122]. These analytical techniques may represent the initial transient flow more accurately [120-121]. By applying a combination of these techniques, geologists have created hybrid methodologies that help to balance the potential bias of each technique as the well transitions from transient flow to boundary-dominated flow. These hybrid methods are new, and it is unclear whether they will prove valuable given the effort associated.

4.2 Implications of decline rate inaccuracy

Based on both simulated and empirically observed well behaviour, some authors have suggested that assuming $b > 1$ results in resource estimates that are 2-100 times greater than the 'reasonable' values derived from completed wells or other estimation techniques [123-124]. Shale gas companies currently active in the four main US shale gas plays have used hyperbolic decline curves with *b* constants of between 1.4 and 1.6 [114]. Analysis of 1957 horizontal wells in Barnett, Fayetteville Woodford, Haynesville and Eagle Ford shale plays [119]] suggests that *b* constants above 1 may be appropriate for unconventional gas in some instances, though *b* constants such as the 1.4 to 1.6 indicated above are not supported. Guidelines from the Society of Petroleum Engineers (SPE) identify a possible range for the *b* constant of between 0 and 1.5 for shale gas, but suggest that a conservative decline rate (lower *b*) be used to derive proved reserve estimates [4]. A more optimistic decline rate (higher *b*) may be used for proved and probable (2P) reserves [4].

Due to the difficulties associated with hyperbolic decline curves, several authors have suggested using a new decline curve formulations know as the 'power-law exponential' rate relation for shale gas wells instead [80, 109, 112]. But while this new formulation could potentially succeed the hyperbolic decline curve as best practice, it seems unlikely to have a significant impact on the estimation of URR in shale gas wells for some time. The continuing concern over the accuracy of hyperbolic decline curves has also prompted some authors to suggest that their use may not qualify under the US Securities and Exchange Commission's (SEC) guidance on the reporting of reserves [89].

These difficulties raise the question: if the URR of shale gas has been overestimated, what are the implications for the future shale gas industry? Overstatement of reserves and 'write-downs' are not unusual in the exploration and production (E&P) business, but they have significant implications – including destruction in shareholder value, costly litigation and loss of confidence in the market. Some indications suggest that downgrading of reserves can erase 30% of a company's share price [125]. In addition, commentators such as Berman [98] have suggested that many existing shale gas wells are not economic. The reporting of large quantities of shale gas resources and the operation of these wells past their point of economic productivity could have depressed the gas price in the United States, creating a more difficult economic climate for E&P companies and eroding shareholder value.

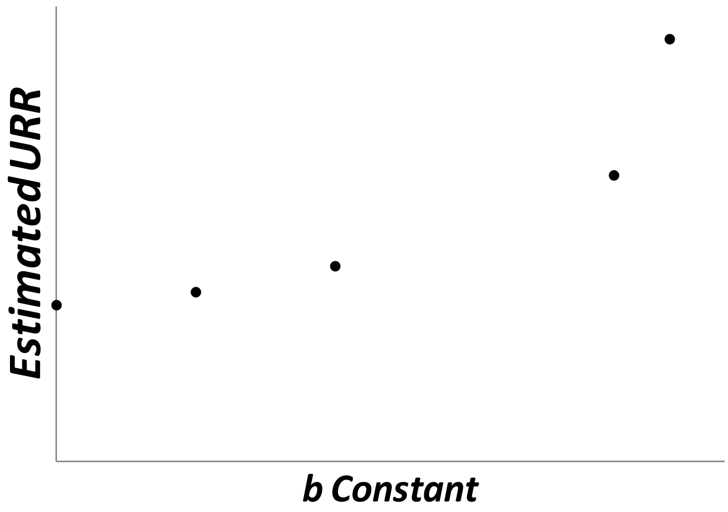
4.3 The modern contentious debate

Recently, the debate over the use of decline rate analysis in unconventional gas reservoirs has become particularly contentious, with authors critical of some aspects of shale gas development highlighting DCA as problematic [97-98, 113]. This has led to both counter arguments [99] and media interest [100-101].

Berman, the most prominent critic of the use of decline rates in shale gas, presented his ideas at a meeting of the Association for the Study of Peak Oil in 2010 [98]. He discussed an analysis by Chesapeake Energy of a group of 44 wells with over 12 months production experience in the Haynesville shale [114]. Chesapeake fit a hyperbolic curve to this data with a b constant of 1.1, leading to a URR estimate for the 44 wells of 185 mcm/well. Berman argues that this estimate is optimistic and shows how curves with a range of different b constants fit the data comparably well (Figure 4-4). Berman suggests that a b constant of 0.5 would more accurately reflect the uncertainty to investors and would give a URR estimate of only 85mcm/well. We have already seen that under some circumstances a b constant of over 1 may be observed. However, it is clear from Figure 4-4 that the sensitivity of URR estimates to b will increase with the value of b, suggesting that small variations in b where $b>1$ have more impact on URR estimates than similar variations in b where $b<1$.

On the basis of this and comparable analyses for other US shales, Berman argues that shale gas production decline may be more accurately modelled by two-stage curve, namely: an initial 10-15 month period of rapid decline followed by a stable, shallower rate of exponential decline (b=0) [126]. This typically leads to a URR estimate that is approximately half of that presented by the operators. Berman also argues that fitting decline curves to the production data from groups of wells can be misleading and lead to further overestimates of the URR. This is because such curves can be upwardly biased by the increasing influence over time of the better performing wells that produce for longer periods and also by the inclusion of production rate increases from new investments at existing wells. However, with careful analysis, such factors can be controlled for.

Figure 4-4: Implications of varying b for estimates of URR for 44 wells in the Haynesville shale



Berman examines the implications of his analysis for shale gas economics and suggests that a well with an estimated URR of 85 mcm (the outcome for b=0.5 in this case) is likely to require a gas price of ~$7/Mcf which compares to current US gas prices of only ~$3.5.[25] This debate has subsequently been explored by the press, with articles in the Financial Times and the New York Times discussing the argument over *b* constants, and the range of opinion over the economic viability of shale gas in the United States [100-101]. These articles have in turn prompted response from some analysts defending the future profitability of shale production in the United States [99]. However, even from this defensive position, it is highlighted that a gas price of between $5.5 and $6 per thousand cubic feet of gas is required to support shale gas production in most of the US regions.

A recent analysis of 8700 horizontal wells in the Barnett Shale [127] lends some support to critics of Berman's position. This analysis groups wells by the number of years they have been in production and uses non-linear regression to find the best fit decline curve for each group. The results suggest hyperbolic decline with *b* values ranging from 1.3 to 1.6, with a

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[25] On the 15th December 2011 Bloomberg.com stated that the NYMEX Henry Hub 1M future was $3.11, the Henry Hub Spot was $3.08, and the New York City Gate Spot was $3.33. These prices are all per million BTU, which when converted to Mcf become $3.02, $3.00 and $3.24 respectively.

mean of 1.5. This leads to a mean URR/well of 56.6 mcm when extrapolating production over an assumed 30 year lifetime. The same analysis also shows that older wells perform better (i.e. decline less rapidly) and speculates that this may be due both to newer wells targeting poor quality rock, and/or to reduced spacing between wells. ‘Re-stimulation’ of wells leads to higher production in the short term, but it is too early to tell whether this also leads to higher ultimate recovery.

In summary, if Berman is correct the US shale gas reserve is likely to be overstated by the gas companies themselves, as well as many independent estimates. But the empirical evidence remains equivocal at present, and several more years of production experience is likely to be required before any firm judgement can be made. In the interim, we may anticipate continued controversy.

5. Best estimates: characterising the uncertainty

5.1 Estimates of shale gas resources

Drawing together the above, Table 5-1 provides a range of estimates of the technically recoverable shale gas resources within 15 global regions. In some regions it was not possible to provide a central estimate due to an absence of sufficient information. It is also important to note the numerous and important caveats to these estimates, summarised in the table and in the following section. The reasons for choosing these particular estimates and/or manner in which they were derived are indicated in the table. Since all estimates refer to technically recoverable resources, they take no account of economic viability or any other constraints on resource recovery. Hence, there is no guarantee that these resources will be produced.

As discussed in Chapter 3, resource estimates based upon the extrapolation of production experience are likely to be more robust. However, with very limited production experience in the majority of the world's regions, it is more appropriate at this stage to incorporate estimates from studies that use a range of methodologies. Since experience with production and resource estimation is growing rapidly, it is also important to use the most recent estimates. Organisations that have provided multiple estimates for single regions (e.g. Kuuskraa/ARI [30, 32, 34, 37, 44, 48, 55, 58, 60] and the EIA [25]) have consistently, and often significantly, increased their estimates over time.

As shown in Table 5-1, it was only possible to obtain high, best and low estimates of recoverable resources for four regions– namely, Canada, United States, China and other developing Asia. For these regions, the high estimate is on average 250% of the best estimate, while the low estimate is 31% of the best estimate. In the United States, the corresponding figures are 230% and 64%. This serves to demonstrate that the range of uncertainty in these estimates is extremely large, even for the United States. Given the comparative absence of production experience in most other regions of the world, the resource estimates should be treated with considerable caution.

Table 5-1: Estimates of shale gas resources

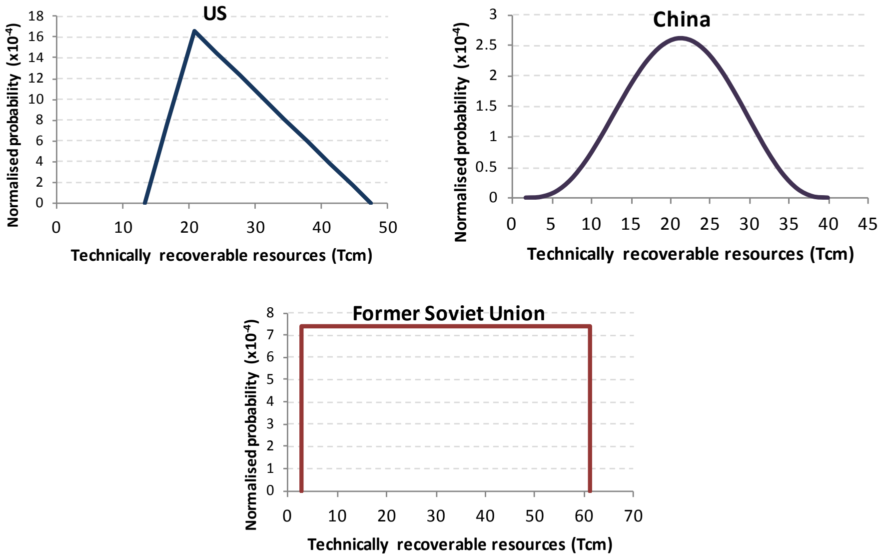
	High	Best	Low	Notes/sources
Africa		29.5		[32]
Australia		6.3		Average of [28] and [32]. Cannot assume that estimate from [32] is the 'high' estimate as this is reported as a conservative assessment.
Canada	28.3	12.5	4.7	Only estimates from 2010 and after have been chosen High: Highest estimate provided [42] Best: mean of [28-29, 32, 40, 42, 46] (ICF estimate assumed to be TRR) Low: [28]
China	39.8	21.2	1.6	High: All of 'Centrally planned Asia' from Rogner [59] with 40% recovery factor Best: Average of [28] and [32] Low: All of 'Centrally planned Asia' from WEC [38] with 15% recovery factor
Central and South America		34.7		[32]
Eastern Europe		4.3		Average of [28] and [32] for Poland
Former Soviet Union	61.2		2.7	High: WEC [38] with 40% recovery factor Low: Rogner [59] with 15% recovery factor
India		1.8		[32]
Japan		0		No sources report any shale gas to be present in Japan
Middle East	28.7		2.8	High: whole of Rogner's [59] MENA region with 40% recovery factor. Low: half of WEC [38] MENA region (as assumed by [32]) with 15% recovery factor
Mexico		11.6		Average of [28] and [32]
Other developing Asia	22.1		1.3	WEC [38] reported OECD Asia and 'Other Asia' collectively so cannot be used High: Rogner [59] 'Other Pacific Asia' and 'Centrally Planned Asia' regions with 40% recovery factor minus best estimate of China from above Low: 'Other Pacific Asia' only (as assume all of Rogner's 'Central Planned Asia' is China) and assuming a 15% recovery factor. This is similar to estimate for Pakistan only from [32]
South Korea		0		No sources report any shale gas to be present in South Korea
United States	47.4	20.0	13.1	Only estimates from 2010 and after have been chosen High: highest estimate available - [29] (assumed to be TRR) Best: mean of three estimates from each category judged to be most suitable - [28, 30] and USGS Low: lowest estimate available - USGS
Western Europe		11.6		Average of [28] and [32] for Sweden and Germany and [32] and [47] for the UK. [32] for France, the Netherlands, Norway and Denmark, and [28] for Austria

Note: All figures are in Tcm

Even for the four regions where high, best and low estimates have been identified, there is no evidence for the shape of the probability distributions that will be found between these points. There is also no evidence of whether the high and low points should be interpreted as absolute maxima and minima or whether they should be seen more as extreme, but not maximum values such as the 95th and 5th percentiles. Given this lack of evidence, a possible approach is to choose as many distributions that are judged to be appropriate, assume that all of these have equal weighting, and combine them using statistical procedures. Given that the high and low points are, in general, not equally spread about the central value, the distributions must be capable of being asymmetric.

Various distributions have been used for such purposes previously [128-129] and would include triangular or beta distributions, with the high and low values at both the maxima and minima and the 95th and 5th percentiles. A selection of possible distributions is shown in Figure 5-1. An aggregate distribution for each region with more than one possible distribution could be derived for example by randomly sampling from each.

Figure 5-1: Examples of possible probability distributions between estimates in a selection of regions



5.2 Confidence in current estimates and conclusions

This section summarises some of the main findings from the preceding sections and assesses whether and to what extent these resource estimates are likely to change in the future.

The focus of this report has been on *original* estimates of unconventional gas resources – and especially shale gas resources – for different countries and regions. Original estimates are defined as those that have been developed using recognised methodologies or derived by adapting figures from existing sources. This criterion excludes the resource estimates published in an influential study by the IEA [130].[26] The IEA takes most of its shale gas

[26] Most of the IEA shale gas resource estimates were taken directly from ARI [32], while the Middle Eastern estimates were based upon Rogner [59] assuming 20% recovery factor. The tight gas resource estimates for all regions, and the CBM resource estimates for North America and Asia/Pacific, were all taken from Rogner

resource estimates directly from ARI [32], while for the Middle East the estimates are based upon the seminal study by Rogner [59] assuming a 20% recovery factor. Rogner is also the source of the IEA tight gas and CBM resource estimates, assuming a 40% and 25% recovery factor respectively. Whether such reliance upon Rogner is reasonable is discussed below.

Only within North America, and predominantly the United States, are any shale gas resources considered proved reserves, and these comprise only a small proportion of the estimated technically recoverable resources.[27] It is thus very important not to confuse reserves with resources. As indicated above, resource estimates are inherently uncertain and all the more so for a resource that is at such an early stage of development. Moreover, this uncertainty is compounded by the use of imprecise or ambiguous terminology. This often results from employing terminology that has been derived for conventional hydrocarbons but is not necessarily appropriate for unconventional resources (e.g. 'undiscovered resources'). Hence, uncertainty could be reduced by more careful and consistent use of terms and definitions or, better still, the development of an appropriate standard such as the SPE/PRMS.

Four general methods have been used to generate resource estimates of shale gas, namely: expert judgement; literature review; bottom up assessment of geological parameters and extrapolation of production experience. These have been described in detail and the strengths and weaknesses of each discussed. While the extrapolation of production experience is potentially the most robust methodology, it relies upon data that is unavailable for most regions of the world. While analogues can be used, the results are sensitive to the particular analogue that is chosen.

With the current state of development of the literature, the differences in resource estimates between institutions using a similar methodological approach are as significant as the differences between those using different approaches. For example, looking at estimates of the US TRR, the differences between the estimates of the USGS and INTEK [18] within the extrapolation category are as great as between Medlock [28] (literature review), USGS (extrapolation) and ICF [131] (geological). A primary source of these differences is the uncertainty over the recovery factor and the URR/well. Hence, emphasis needs to be placed

assuming 40% and 25% recovery factors respectively. The IEA also provides a CBM resource estimate for Eastern Europe/Eurasia, but it is not clear how this was derived. The figure of 85 Tcm would require a 75% recovery factor to correlate to Rogner's estimate of CBM OGIP. Alternatively, an OGIP of 340 Tcm would be required if a 25% recovery factor is assumed - which is significantly greater than any other estimate of **global** CBM OGIP.

[27] Proved reserves reported by the EIA [84] for 2009 are 1.7 Tcm and so comprise only 9% of the best estimate of TRR given in Table 5-1.

on constraining these parameters to a greater degree than at present and on incorporating probabilistic techniques to capture their inherent uncertainty.

There is an absence of rigorous studies for a number of key regions across the world. This includes Russia and the Middle East, which are estimated to hold potentially very large resource volumes (Table 5-1). While Rogner [59] and the World Energy Council [38] provide independent estimates for these regions, they provide very little information on their methodology and their methods are potentially flawed. For example, Rogner used a single analogue from the United States to estimate recoverable resources across the whole world. But since subsequent US experience has demonstrated a wide variation both within and between shale plays, the choice of a different analogue could have led to very different results. The WEC provides no references for the literature relied upon for its study. This makes reliance on other studies preferable whenever possible although in many regions Rogner and the WEC are the only sources that are available.

As mentioned above, the estimates produced by bottom up geological assessments are very sensitive to the assumed recovery factor. While it is generally accepted that estimating recovery factors is challenging, little progress appears to have been made in establishing such factors for shale, even when the geology is well understood. Uncertainty over this factor, which is currently estimated to be between 15% and 40% for shale gas production, makes an accurate estimate of TRR very difficult – even assuming the OGIP can be established with any confidence.

In a similar manner, many of the estimates produced by extrapolation methods are sensitive to the assumed URR/well and hence to the choice and parameterisation of the relevant decline curves. The application of decline curve analysis to shale gas production is contested, with no consensus on how quickly the rate of production decline will slow. Of particular concern is the fact that a small change in assumptions in these analyses may have a large effect on the estimated URR of a well and hence on the estimated URR for a region. It is therefore important to focus attention on refining these techniques and developing comprehensive assessments of their accuracy. A significant amount of work has been conducted in recent years into refining extrapolation methods, but further work is needed to prove these new methods, and establish them as best practice if genuine improvement is to be achieved.

It is important to note that while bottom-up estimates are uncertain, they are informed by some level of historical experience, and are often bounded at the individual well or play level. This may limit the uncertainty relative to that for top-down estimates of regions or countries where there is limited or no historical experience, and the estimates of URR or TRR may be highly uncertain, and sensitive to small changes in assumptions.

Another uncertainty influencing shale gas estimates is the practice of simply delineating shale play areas into more and less productive areas. Splitting a shale play into only these two areas implies that comparable production rates and URR/well will be experienced across the whole of these areas. This assumption belies the true heterogeneity of shale plays. In addition, production to date has focused upon areas with the highest productivity and URR/well. Assuming that comparable production rates will be experienced across the remainder of the play is likely to lead to overestimates of the TRR. The large areal extent of many shale plays means that inadequate delineation could a have large effect on the results, although this source of uncertainty should reduce as drilling continues and the extent to which different areas can be grouped together becomes more obvious.

A related uncertainty is the validity of assumptions for URR/well and well spacing in areas outside those from which production is currently taking place. Even though assumptions for these areas are necessary to estimate to resource potential of the whole shale play, the level of confidence in these assumptions is much lower than that for developed areas.

There is also uncertainty over the impact that technology will have on increasing current estimates of TRR. Previous forecasts of the potential impact of technological improvements failed to anticipate the increase in URR/well that has occurred since the 1980s. The technologies currently being used for shale gas extraction are now better understood, having been much more widely studied and utilised than previously. In addition, shale geology is now much better understood, suggesting potential improvements in technology can now be better characterised. Nevertheless, technological progress, even if only leading to a small increase in URR/well or recovery factor, can have a significant impact on the estimated ultimately recoverable resources and it is impossible to rule out future major technological breakthroughs.

Finally, the potential for shale gas in as yet undiscovered basins is likely to be low but probably not insignificant and requires further investigation.

In conclusion, there are multiple and substantial uncertainties in assessing the recoverable volumes of shale gas at both the regional and global level. Even in areas where production is currently taking place, there remains significant uncertainty over the size of the resource and considerable variation in the available estimates. For undeveloped regions where less research has been conducted, one estimate of resources may be all that is available and the range of uncertainty cannot be characterised. For several regions of the world there are no estimates at all, but this does not necessarily mean that such regions contain only insignificant resources. Therefore, given the absence of production experience in most regions of the world, and the number and magnitude of uncertainties described above, current resource estimates should be treated with considerable caution.

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7. Annex 1

Table 7-1: Documentation and classification of the evidence base

Author	Date	Peer review	Countries/ regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
Aluko	Aug-01	No	11 countries	CBM	TRR	Literature review	
ARI (Kuuskraa)	May-11	No	United States	Shale	TRR	Method not stated	It is likely that Kuuskraa adopts a bottom up analysis of geological features approach as used in ARI April 2011 report, but this is not stated
ARI (Kuuskraa, Stevens et al.)	Apr-11	Yes	32 individual countries worldwide	Shale	OGIP and TRR	Bottom up analysis of geological parameters	
ARI (Kuuskraa)	Jan-11	No	United States	Shale CBM Tight	TRR TRR TRR	Method not stated Method not stated Method not stated	
ARI (Kuuskraa)	Oct-10	No	United States	Shale	TRR	Method not stated	
ARI (Kuuskraa)	Mar-10	No	United States, Canada	Shale	TRR	Method not stated	

Author	Date	Peer review	Countries/ regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
ARI (Kuuskraa)	Dec-09	No	Rest of World	Shale	TRR	Not independently assessed: based on Rogner (1997) and IEA WEO 2009	Recovery factor of 40% suggested
			United States, Canada, Poland, Sweden, Austria, South Africa	Shale	'Recoverable resources'	Method not stated	
			Global	Tight	TRR	Not independently assessed: based on Rogner (1997) and IEA WEO 2009	Recovery factor of 50% suggested
			Individual countries worldwide	CBM	OGIP and TRR	Method not stated	
ARI (Kuuskraa)	Jul-07	No	United States	Shale	URR	Bottom up analysis of geological parameters	
				CBM	URR	Bottom up analysis of geological parameters	

Author	Date	Peer review	Countries/ regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
				Tight	URR	Bottom up analysis of geological parameters	
BGR (Kümpel)	Nov-09	No	Individual countries worldwide	CBM	TRR	Method not stated	
			Continental regions	Shale	OGIP	Not independently assessed: based on Holditch & Chianelli, Kawata & Fujita & Rogner	No recovery factor suggested
				Tight	OGIP	Not independently assessed: based on Holditch & Chianelli, Kawata & Fujita & Rogner	No recovery factor suggested
Caineng et al.	Dec-10	Yes	China	Shale	OGIP	Bottom up analysis of geological parameters	
Chatham House (Stevens)	Sep-10	No	Continental regions	Shale	OGIP	Not independently assessed: based on Holditch (2007)	

Author	Date	Peer review	Countries/ regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
Dawson	May-10	No	Canada	Shale	ERR	Method not stated	Indicates was based on Petrel Robertson Consulting (2010) report, however this report does not include any ERR figures.
				CBM	ERR	Method not stated	
				Tight	ERR	Method not stated	
DECC (Harvey and Gray)	Jan-10	No	UK	Shale	TRR	Extrapolation of production experience	
EIA (AEO)	Various	No	United States	Shale	TRR	Bottom up analysis of geological parameters	There have been a total of 15 Annual Energy Outlooks between 1997 and 2011. The AEO in 2003 used the same unconventional gas figures as 2002, while the 2011 estimate was based entirely on INTEK (2011) and so is reported separately.

Author	Date	Peer review	Countries/ regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
FERC	May-10	No	United States	Shale	TRR	Not independently assessed: based on 'American Clean Skies Foundation'	
Geny	Dec-10	No	Europe	CBM	TRR	Not independently assessed: based on Wood Mackenzie ‘Unconventional Hydrocarbons’ Multi-client Study	
				Tight	TRR	Not independently assessed: based on Wood Mackenzie ‘Unconventional Hydrocarbons’ Multi-client Study	

Author	Date	Peer review	Countries/ regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
				Shale	TRR	Not independently assessed: based on 'IHS CERA Gas from Shale: Potential Outside North America?'	
Global Warming Policy Foundation (Ridley)	Apr–11	No	Global	Shale	OGIP and TRR	Not independently assessed: based on ARI report	
				CBM	OGIP and TRR	Not independently assessed: based on ARI report	
Hennings	Mar–10	No	United States	Shale	OGIP and TRR	Bottom up analysis of geological parameters	
Holditch & Chianelli	Apr–08	Yes	Continental regions	Shale	OGIP	Not independently assessed: based on Rogner (1997) (although not stated)	No recovery factor suggested

Author	Date	Peer review	Countries/ regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
				CBM	OGIP	Not independently assessed: based on Rogner (1997) (although not stated)	No recovery factor suggested
				Tight	OGIP	Not independently assessed: based on Rogner (1997) (although not stated)	No recovery factor suggested
Holditch	Jul-07	No	Continental regions	Shale	OGIP	Not independently assessed: based on 'Tight Gas Sands' Holditch (2006)	
				CBM	OGIP	Not independently assessed: based on 'Tight Gas Sands' Holditch (2006)	

Author	Date	Peer review	Countries/ regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
				Tight	OGIP	Not independently assessed: based on 'Tight Gas Sands' Holditch (2006)	
Holditch	Jun-06	Yes	Continental regions	Shale	OGIP	Not independently assessed: based on Rogner (1997) taken from Kawata and Fujita (2001). No recovery factor stated	No recovery factor suggested
				CBM	OGIP	Not independently assessed: based on Rogner (1997) taken from Kawata and Fujita (2001). No recovery factor stated	No recovery factor suggested

Author	Date	Peer review	Countries/ regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
				Tight	OGIP	Not independently assessed: based on Rogner (1997) taken from Kawata and Fujita (2001). No recovery factor stated	No recovery factor suggested
ICF	Mar-09	No	United States	Shale	TRR	Bottom up analysis of geological parameters	Reported by MIT supplementary paper (Ejaz (2010) SP2.2) We consider that all of ICF's estimates are better interpreted as TRR
				CBM	TRR	Bottom up analysis of geological parameters	We consider that all of ICF's estimates are better interpreted as TRR
				Tight	TRR	Bottom up analysis of geological parameters	We consider that all of ICF's estimates are better interpreted as TRR.

Author	Date	Peer review	Countries/ regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
ICF (Petak)	Jun-11	No	United States. Canada	Shale	ERR	Bottom up analysis of geological parameters	This report indicates that there is a total of 61.5 Tcm of economically recoverable resource in the US and Canada. It provides a supply cost curve indicating that this volume is only recoverable at gas prices greater than $14/Mcf. Since this price is four times higher than current gas prices (around of $3.5/Mcf on 15th December 2011), we consider that all of ICF's estimates are better interpreted as TRR.
ICF (Henning)	Mar-11	No	United States, Canada	Shale	ERR	Bottom up analysis of geological parameters	We consider that all of ICF's estimates are better interpreted as TRR.
ICF (Vidas & Hugman)	Nov-08	No	United States, Canada	Shale	OGIP and TRR	Bottom up analysis of geological parameters	
				CBM	TRR	Method not stated	
				Tight	TRR	Method not stated	

Author	Date	Peer review	Countries/ regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
IEA (Priddle)	Jan-11	Yes	Continental regions	Shale	TRR	Not independently assessed: based on ARI report (Kuuskraa, Stevens et al. 2011)	
				CBM	TRR	Not independently assessed: based on Rogner (1997)	Recovery factor of around 25% suggested
				Tight	TRR	Not independently assessed: based on Rogner (1997)	Recovery factor of around 40% suggested
IHS CERA (Downey)	Jan-10	No	United States, Canada	Shale	TRR	Method not stated	
IHS CERA	Feb-09	No	Europe	Shale	TRR	Unknown	Reported by Weijermars, R., et al., Unconventional gas research initiative for clean energy transition in Europe. Journal of Natural Gas Science and Engineering, 2011. 3(2): p. 402-412.

Author	Date	Peer review	Countries/ regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
INTEK (for EIA)	Jul–11	No	United States	Shale	'Unproved, undiscovered TRR'	Extrapolation of production experience	TRR can be derived from this figure though adding proved and inferred reserves, and undiscovered resources which are reported separately
Kawata and Fujita	Apr–01	No	Continental regions	Shale	OGIP	Not independently assessed: based on Rogner (1997)	No recovery factor suggested
				CBM	OGIP	Not independently assessed: based on Rogner (1997)	No recovery factor suggested
				Tight	OGIP	Not independently assessed: based on Rogner (1997)	No recovery factor suggested
Kuhn & Umbach	May–11	Yes	Continental regions	Shale	OGIP and TRR	Not independently assessed: based on BGR [72]	
				CBM	TRR	Not independently assessed: based on BGR [72]	
				Tight	TRR	Not independently assessed: based on BGR [72]	

Author	Date	Peer review	Countries/ regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
Kuuskraa	Jan-04	No	United States	Shale	URR and TRR	Method not stated	
Kuuskraa	Jan-98	No	12 countries	CBM	OGIP and TRR	Method not stated	Reported in Kuuskraa, V.A., Natural gas resources, unconventional, in Encyclopedia of Energy, C.J. Cleveland, Editor. 2004, Elsevier Inc. p. 257-272.
Kuuskraa	Oct-92	No	12 countries	CBM	OGIP and TRR	Extrapolation from coal resources	
				CBM	URR and TRR	Method not stated	
				Tight	URR and TRR	Method not stated	
Kuuskraa & Meyers	Jan-83	No	United States, Canada, ROW	Shale	OGIP and TRR	Literature review	Could equally be an expert opinion
				Tight	OGIP and TRR	Literature review	Could equally be an expert opinion
			Continental regions	CBM	OGIP and TRR	Bottom up analysis of geological factors	
Laherrere	Jun-04	No	Global	Shale	URR	Expert judgment	
Medlock & Hartley	Oct-10	No	United States, Canada	Shale	TRR	Literature review	

Author	Date	Peer review	Countries/ regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
Medlock *et al.*	Jul–11	Yes	9 North American, European and Pacific countries	Shale	TRR	Literature review	Medlock indicates that resource should be commercially viable so his definition, although described as technically recoverable resources, could be closer to ERR.
MIT (Moniz)	Jun–10	Yes	United States	Shale	TRR	Literature review	Figures are reported without proved reserves so 1.7 Tcm gas have been added
				CBM	TRR	Literature review	Figures are reported without proved reserves so 0.54 Tcm gas have been added
				Tight	TRR	Literature review	Figures are reported without proved reserves so 2.3 Tcm gas have been added
			Continental regions	Shale	OGIP	Not independently assessed: based on Rogner (1997)	Reported in appendix 2A. Recovery factor between 10–35% suggested
				CBM	OGIP	Not independently assessed: based on Rogner (1997)	Reported in appendix 2A. Recovery factor between 10–35% suggested

Author	Date	Peer review	Countries/ regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
				Tight	OGIP	Not independently assessed: based on Rogner (1997)	Reported in appendix 2A. Recovery factor between 10–35% suggested
Mohr & Evans	Sep-11	Yes	Continental regions	Shale	URR	Literature review	
				CBM	URR	Literature review	
				Tight	URR	Literature review	
Mohr & Evans	Jul-10	Yes	United States, Canada	Shale	URR	Literature review	
				CBM	URR	Literature review	
				Tight	URR	Literature review	
Murray	Jan-96	Yes	12 countries	CBM	OGIP	Adaptation of existing review (Kuuskraa et al 1992)	
Navigant Consulting (Smead & Pickering)	Jul-08	No	United States	Shale	TRR	Literature review	
				CBM	TRR	Literature review	
				Tight	TRR	Literature review	

Author	Date	Peer review	Countries/ regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
Palmer	Mar–08	No	12 regions/countries	CBM	OGIP	Not independently assessed: based on Kuuskraa (1992)	
Petrel Robertson Consulting	Mar–10	No	Canada	Shale	OGIP	Literature review	
				CBM	OGIP	Literature review	
				Tight	OGIP	Literature review	
Potential Gas Committee	Apr–11	No	United States	Shale	TRR	Bottom up analysis of geological parameters	
			United States	CBM	TRR	Bottom up analysis of geological parameters	
Potential Gas Committee	Jun–09	No	United States	Shale	TRR	Bottom up analysis of geological parameters	
			United States	CBM	TRR	Bottom up analysis of geological parameters	
Rogner	Jan–97	Yes	Continental regions	Shale	OGIP	Extrapolation of production experience	

Author	Date	Peer review	Countries/ regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
				CBM	OGIP	Literature review	
				Tight	OGIP	Literature review	The global figure was modified to regional estimates based on the distribution of conventional gas
Ryan	Dec-08	No	12 regions/countries	CBM	OGIP	Not independently assessed: based on Wood Mackenzie 'Unconventional Hydrocarbons' Multi-client Study	
				Tight	OGIP	Not independently assessed: based on Wood Mackenzie 'Unconventional Hydrocarbons' Multi-client Study	
Sandrea	Dec-05	No	United States	Tight	TRR	Extrapolation of production experience	

Author	**Date**	**Peer review**	**Countries/ regions covered**	**Gas analysed**	**Type of resource estimate**	**Approach used**	**Notes**
			United States, Global	Shale	'Recoverable reserves'	Expert judgment	
				CBM	'Recoverable reserves'	Expert judgment	
Schulz	Jan-10	Yes	Europe	Shale	OGIP	Not independently assessed: based on Rogner (1997)	No recovery factor suggested
Skipper	Mar-10	No	United States, Canada	Shale	TRR	Method not stated	
Theal	May-09	No	United States, Canada	Shale	OGIP and TRR	Bottom up analysis of geological parameters	
Total	Jan-06	No	5 regions	Tight	TRR	Method not stated	
			Global	Tight	OGIP and TRR	Method not stated	

Author	Date	Peer review	Countries/ regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
USGS	Aug-11	No	United States	Shale	'Potential to be added to reserves'	Extrapolation of production experience	USGS resource estimate based on Coleman et al. (2011), Dubiel et al. (2011), Higley et al (2011), Houseknecht et al. (2010), Schenk et al. (2008), Swezey et al. (2007), Swezey et al. (2005), Pollastro et al. (2004) Higley et al.(2003), Milici et al (2003) and USGS (2010).
				CBM	'Potential to be added to reserves'	Extrapolation of production experience	
				Tight	'Potential to be added to reserves'	Extrapolation of production experience	
Wood Mackenzie	Jan-09	No	Europe	Shale	TRR	Method not stated	Reported by Weijermars, R., et al., Unconventional gas research initiative for clean energy transition in Europe. Journal of Natural Gas Science and Engineering, 2011. 3(2): p. 402-412.

Author	Date	Peer review	Countries/ regions covered	Gas analysed	Type of resource estimate	Approach used	Notes
Wood Mackenzie	Nov-06	No	12 regions/countries	CBM	OGIP	Unknown	Reported by Ryan (2008) and Geny (2010). Figures appear to be similar to Rogner's
				Tight	OGIP	Unknown	Reported by Ryan (2008) and Geny (2010). Figures appear to be similar to Rogner's
World Energy Council	Sep-10	No	9 regions	Shale	OGIP	Literature review	Recovery factor of 40% suggested to convert to ERR