The Future of Natural Gas

Supplementary Paper SP2.1

Natural Gas Resource Assessment Methodologies

(Ejaz)

Techniques for estimation of recoverable resources of natural gas depend crucially on geological, geophysical, and discovery and production data available. This paper discusses assessment methodologies for reserves, reserve growth, undiscovered technically recoverable (conventional) resources, and unconventional resources employed by relevant agencies. Proved reserves are reported by the Energy Information Agency (EIA), while the other categories are assessed by the United States Geological Survey (USGS), the Minerals Management Service (MMS), the Potential Gas Committee (PGC), the National Petroleum Council (NPC) and ICF International, among others.

This paper is organized by resource category and then by assessing agency. Reserves and proved reserves are discussed in the first section. The second section contains a discussion on reserve growth and the methodology used by each relevant agency. The last two sections discuss methodologies for assessing conventional and unconventional ultimately technically recoverable resources (UTRR). Only agencies whose results have been used in this study are included in this paper.

Assessment Methodology for Reserves

The Society of Petroleum Engineers (SPE) has developed a detailed procedure for the accounting of reserves, or known volumes of oil and gas (Etherington & Ritter 2007). Reserves in the US are reported by the EIA and are identical to reserves reported to the SEC by oil and gas companies. There are several publications (Cedigaz, BP Statistical Review, Oil and Gas Journal) that survey publicly available data from companies and countries and report gas reserves at the country or regional level for the entire world. The data compiled in these publications is available from the EIA.

Reserves can be loosely described as the economically recoverable part of discovered natural gas resources. Gas reserves consist of gas volumes that have been discovered and confirmed, and which have a development plan demonstrating commercially viable production at prevailing prices. The rigor with which these criteria are observed in different parts of the world depends crucially on the regulatory regimes of countries, the nature of their financial and gas markets, and the control of the state over the resources and companies developing them. For example, the US has a large, liberalized gas market, with hundreds of gas producers. Companies operating in the US or reporting on the US stock exchange must report carefully defined proved reserves to the SEC. In other parts of the world, reserve reporting requirements are less clearly and stringently defined. In addition, much of the reserve base is owned by national companies, which may introduce political considerations into the reporting of reserves.

SPE documentation describes 1P (proved) reserves with a 90% probability of being exceeded, 2P (probable) reserves that have between a 50% and 90% probability of being exceeded, and 3P (possible) reserves that have between a 10% and 50% probability of being exceeded, under the existence and economic conditions described above (SPE et al. 2007). Companies in the US and international companies reporting on US stock exchange are subject to stringent SEC requirements that require reported reserves to be proved (1P reserves). Companies in the rest of the world are not necessarily subject to such stringent requirements.

An illustration of 1P and 2P reserves is shown in Figure 1.

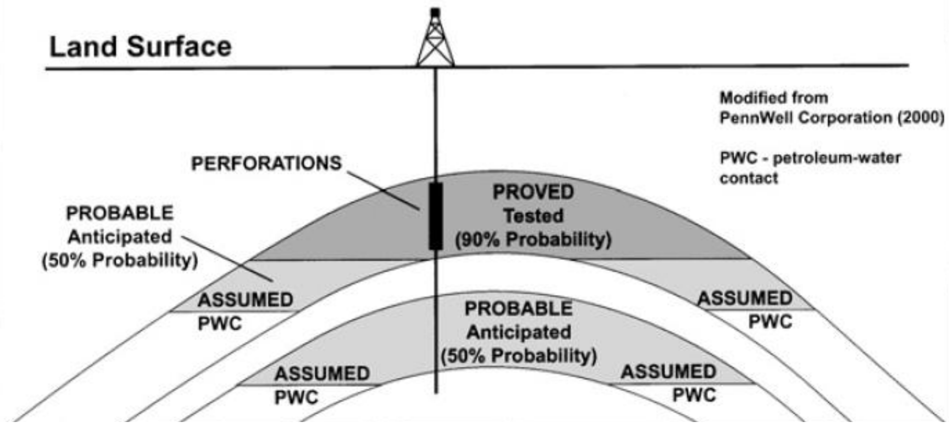

Figure 1: An illustration of proved (1P) and probable (2P) reserves, reproduced from (Klett 2005)

EIA Assessment Methodology for Reserves

As mentioned earlier, proved reserves data for the US are compiled, estimated and reported by the EIA from company data. The EIA defines proved reserves as “those volumes of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in the future years from known reservoirs under existing economic and operating conditions” [Appendix G of EIA reserves report (Energy Information Administration 2009)]. These reserves can be estimated either by deterministic methods, where “reasonable certainty” means a high degree of confidence, or using probabilistic techniques, in which case it means there is a 90% probability that the actual quantities will be greater than or equal to the reserves value. The EIA further classifies reservoirs as either proved producing or proved non-producing, depending on whether or not there was any production from a given reservoir in the report year.

The EIA uses Form EIA-23, which encodes a standardized definition of proved reserves, to conduct a survey of oil and gas operators in the US. Proved reserves estimates of hydrocarbons are based on the best available geological, engineering, and economic data available. They also depend on the judgment of the appraiser. Consequently estimates of proved reserves for any given reservoir may vary from company to company. The position of proved reserves in the hierarchy of natural gas resources is shown in Figure 2.

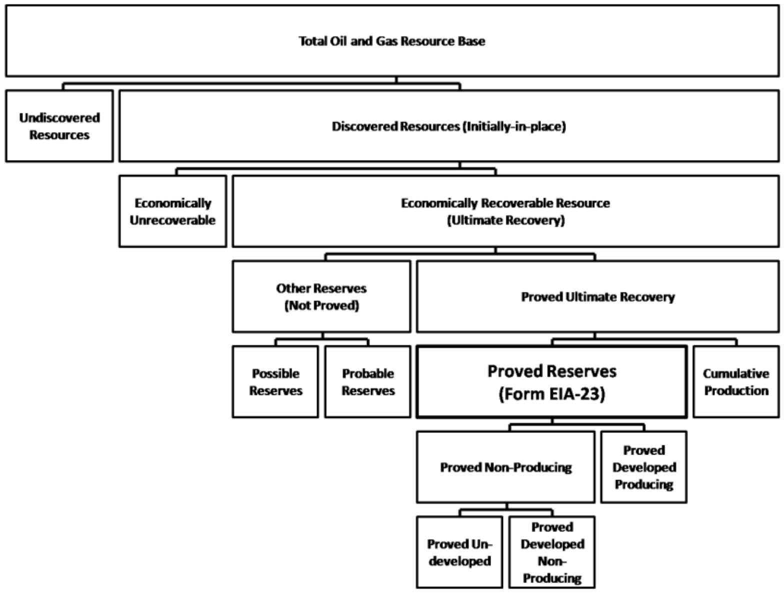

Figure 2: The position of proved reserves in the hierarchy of natural gas resources is shown. Proved reserves correspond to the 1P reserves category of SPE-PRMS (SPE et al. 2007), while probable and possible reserves correspond to 2P and 3P reserve categories respectively. Probable and possible reserves are not reported by EIA. This figure is reproduced from Appendix G of (Energy Information Administration 2009).

Because individual field and reservoir data often exhibit considerable heterogeneity, there is statistical variation in reserve estimates for a field or reservoir. In turn this can affect the accuracy of reserves estimates[1]. Heterogeneity arises from, among other things, the level of field development and methods used by operators and surveyors to collect and report reserves data.

Assessment Methodology for Reserve Growth

Reserve growth[2] is the category of resources that bridges the gap between reserves and undiscovered resources. It consists of extensions of accumulations which are estimated to be partially developed and of new pools which may be discovered in an already discovered field. More concretely, they are "cumulative future additions to proved reserves in oil and gas fields discovered as of a certain date" (Attanasi & Coburn 2004). Illustrations of mechanisms that lead to increases in proved reserves estimates are shown in Figure 3 and Figure 4.

[1] An appraiser will choose a method to estimate proved reserves tailored to the level of detail and quality of available data. Production Decline, Material Balance (for crude oil) or Pressure Decline (for gas), and Reservoir Simulation are popular methods for reserve estimation These methods are of comparable accuracy and tend to produce estimates that prove more accurate than methods based solely on geologic and engineering data. The *Volumetric* method and the *Nominal* method for reserve estimation are not based on production data.

[2] Reserve growth is alternatively called inferred reserves, reserves appreciation, growth to known and ultimate recovery appreciation in the literature.

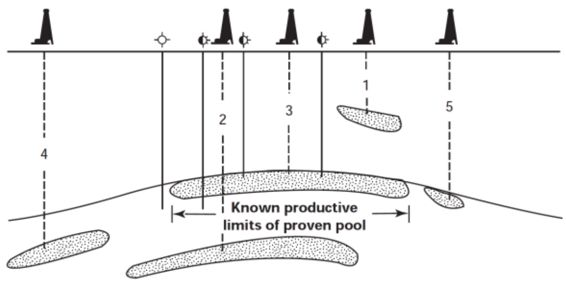

Figure 3: Schematic of wells leading to reserve growth in discovered conventional fields with an emphasis on the discovery of new pools in a productive field. 1, shallower pool test; 2, deeper pool test; 3, infill well; 4, new pool test; 5, extension or outpost; open symbol, dry hole; half-filled symbol, successful producers (see (Attanasi & Coburn 2004)). These definitions are not without ambiguity and an operator or regulatory body may classify accumulations penetrated by wells 1 – 5 as part of one field or different fields. This situation is complicated further by the order in which the wells are drilled.

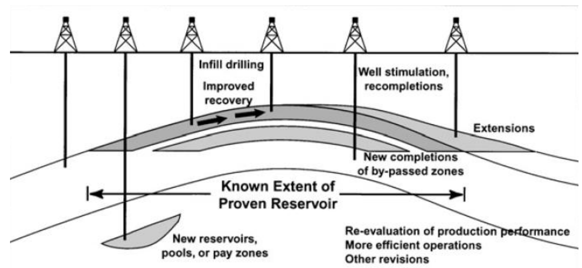

Figure 4: Mechanisms that lead to reserve growth, with an emphasis on infill drilling, improved recovery, well stimulation and recompletion, and extensions of the proven reservoir. These techniques that enhance recovery have a larger impact on reserves for oil fields vs. gas fields for conventional resources. This figure has been reproduced from (Klett 2005).

Reserve growth estimates may be based on analysis of patterns of field growth over time seen in historical field size data. Alternatively, on a volumetric analysis of reservoirs and fields already discovered. The USGS published a reserve growth study for the US as part of its 1995 National Assessment. This reserve growth study provided reserve growth projections for the 2000 World Assessment. USGS is currently conducting another reserve growth study for the US, but has not yet released results. The PGC includes reserve growth in its bi-annual assessment of US resources, and reports it as "Probable Resources." The 2003 NPC study also includes US, Canadian and Mexican reserve growth estimates. These methodologies are discussed below.

The USGS 2000 World Assessment is the only study that attempts to address reserve growth for the entire world. A key assumption is that US reserve growth data can be used as an analogue for the rest of the world. This is a significant assumption, and there are two important reasons to question its validity. The first, discussed above, is the difference in reporting requirements between the US and the rest of the world. US reported reserve volumes must meet stringent reporting requirements that are often not in force elsewhere. US reported reserves thus have more room for growth as companies move discovered fields along the production and extension "conveyor belt". A second reason is that most currently producing US fields contain many small pools and horizons not evident at the time of initial field discovery. As these small pools and new horizons are discovered and confirmed with infill drilling, proved reserves as a proportion of initially reported reserves can increase substantially. In many countries, such as Iran, Qatar and Russia, a significant portion of reserves is situated in super giant and giant fields, where it is easier to delineate field size at the start of the field life, and therefore the opportunity for reserve growth is more limited.

USGS Reserve Growth Assessment Methodology

The data used by the USGS for its reserve growth study consists of estimates of known recovery (production and proved reserves) of conventional oil and gas fields discovered after 1901 but before 1992, located in onshore areas and state waters of the US. They used field level data from the American Petroleum Institute (API), the American Gas Association (AGA) and NRG Associates, and more recently from the Oil and Gas Integrated Field File (OGIFF) compiled and maintained by EIA through its annual survey of confidential company data for proved reserves; and available only to government agencies.

Their first step was to construct a discovery table of conventional gas field volumes and conventional oil field volumes vintage by year of estimate. Ultimate recovery (sum of cumulative production and reserves) is recorded in a discovery table. An example of a discovery table is shown in Table 1. If ultimate recovery for a field of vintage year t_{0i}, at later year $t > t_{0i}$ is denoted by $c(t_{0i}, t)$, then ultimate recovery after Δt years is estimated by

$$\hat{c}(t_{0i}, t + \Delta t) = c(t_{0i}, t) \times \frac{G(t + \Delta t - t_{0i})}{G(t - t_{0i})}, \tag{1.1}$$

where $G(n)$is the growth function for n years.

Their analysis shows that fields can be categorized as either *common* or *outliers*, with the latter growing much faster than the former. Next, cumulative growth functions were estimated by minimizing the least square error of ultimate recovery estimates generated by use of growth functions *G*. The least squares sum is $SSE = \sum_{i,t,\Delta t}\left(\hat{c}(t_{0i}, t + \Delta t) - c(t_{0i}, t + \Delta t)\right)^2$, and the resulting growth functions are shown in Figure 5.

A key assumption is that total recovery in fields of a given vintage does not shrink with age ($G(n) \leq G(n+1)$). For common fields, an additional constraint is that total known recovery in older vintages cannot grow by a larger factor in one year than total known recovery in a younger vintage i.e.

$$\frac{G(n+1)}{G(n)} \leq \frac{G(n)}{G(n-1)}. \tag{1.2}$$

This assumption does not hold for outlier fields where growth in a subsequent year can be greater than a prior year. Finally a maximum cut-off is placed at 91 years, i.e. a vintage no longer grows after it has reached a maximum of 91 years after discovery.

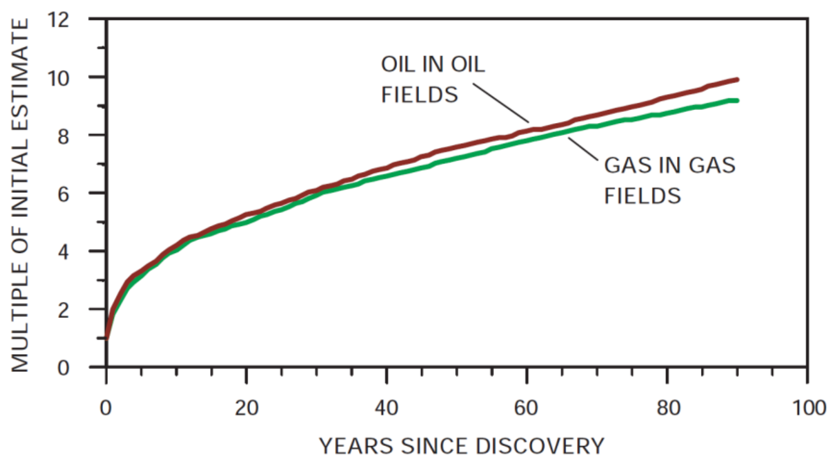

Figure 5: Cumulative, monotone field growth functions for oil in oil fields (red) and gas in gas fields (green). These functions are determined using data from EIA's OGIFF issued in 1993 with data through 1991.

USGS reserve growth estimator uncertainty is computed by (Attanasi & Coburn 2004) using the bootstrap[3] (Efron & Gong 1983). Field data from 1977 to 1991 (15 years) is grouped by vintage. The data contains, for each field, the production history and the reserves for each year. Reserves and production histories are combined to create an estimate of field size for each field in a given year between 1977 and 1991. This data is then organized into a discovery table, an example of which is shown in Table 1.

Table 1: Layout of discovery table for non-associated gas in gas fields; reproduced from (Attanasi & Coburn 2004). Gas volumes are given in Bcf.

Discovery Year	1977	1978	1979	1980	1981	1982	No. of fields by Vintage
1975	2538	2873	2944	3196	3260	3303	317
1976	1555	1714	1841	2156	2417	2505	340
1977	1323	2087	2630	2881	3285	3617	509
1978	0	1012	1801	2752	2952	3500	422
1979	0	0	922	1791	2799	3067	438
1980	0	0	0	784	1533	2252	453
1981	0	0	0	0	891	1441	491

To construct one boot strap realization, each vintage is sampled with replacement to create a bootstrap sample of that vintage. The field records in this sample are then summed to create

[3] Bootstrapping is a statistical method for estimation of properties of a sampled population by "resampling" the sample itself. The probability distribution of a statistic corresponding to a property of a sampled population is computed by taking many (mutually independent) samples *with replacement* from a single observed sample: if the observed sample x is of size n, draw a sample with replacement of size n from it; repeat many times and record the empirical distribution of the statistic T(x) of interest. For moderate to large samples from the population, the resulting empirical distribution of T(x) is a reasonable approximation to the true distribution of T(x). See, for example, (Efron and Gong 1983).

the statistic of interest, i.e. additions to reserves, in the discovery table. The growth function is then calculated for this discovery table. This procedure is repeated 2000 times for oil fields and 2000 times separately for gas fields.

Table 2: The 90% confidence interval for the USGS reserve growth estimate for the US, at 30 years and 80 years, as estimated by (Attanasi & Coburn 2004), is shown in this table.

	Resource Type	Units	5%	base	95%
30 yrs	Total Oil	MMBO	16.6	27.4	44.8
	Associated Gas	TCFG	28.1	50.8	82.4
	Non-associated Gas	TCFG	110.4	138	188.4
	Total Gas	TCFG	148.4	188.8	243.2
80 yrs	Total Oil	MMBO	22.4	39.7	69.5
	Associated Gas	TCFG	40	77.5	137.9
	Non-associated Gas	TCFG	161.9	215.6	343.4
	Total Gas	TCFG	216.7	293.1	412.9

To estimate the confidence interval[4], the bootstrap distribution median is re-centered over the base case value (mean). The results of this analysis done after a time interval of 30 years and 80 years are shown in Table 2.Bootstrap distributions for total gas after 80 years are shown in Figure 6.

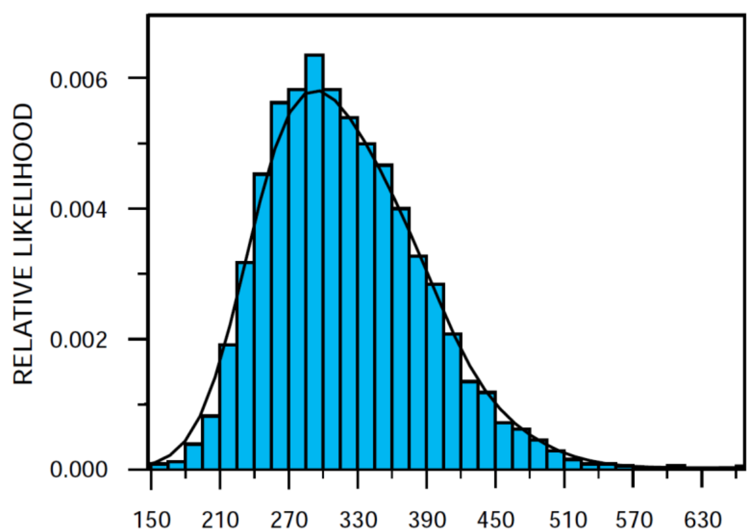

Figure 6: The bootstrap distribution for the total (associated and non-associated) US gas reserve growth, after 80 years, is reproduced here from (Attanasi & Coburn 2004). The horizontal axis shows gas in Tcf.

As mentioned earlier, due to differences in reserve reporting requirements and geology, reserve growth patterns outside the US may be significantly different. These issues are explored

[4] As the empirical bootstrap distribution does not fit any simple well known parametric probability distribution, well, (Attanasi & Coburn 2004) construct a non-parametrical confidence interval. For a given fractile α, the $1-2\alpha$ interval in year k is given by $\left[Q^{-1}\left(S(2z_0 - z_\alpha)\right), Q^{-1}\left(S(2z_0 + z_\alpha)\right)\right]$, where Q is the bootstrap cumulative distribution, S is the standard normal cumulative distribution, $S(z_\alpha) = 1-\alpha$, and $z_0 = S^{-1}\left(Q(\hat{p}_k)\right)$. Here $\hat{p}_k$ is the base case reserve growth for year k. This procedure is based on standardization of the difference between the reserve growth base case $\hat{p}$ and the median of the empirical bootstrap distribution.

by (Verma & Ulmishek 2003) for oil field reserve growth. A summary their results in Figure 7 show that field reserve growth varies as a function of geography, geology and reporting requirements.

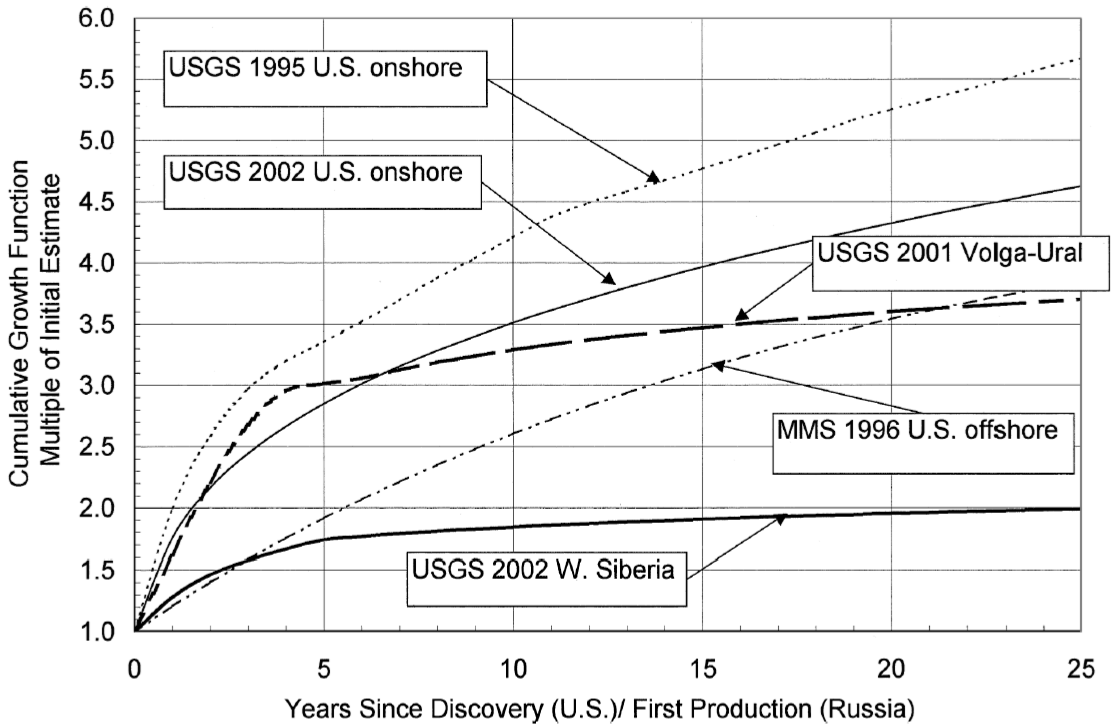

Figure 7: Five oil field reserve growth curves are shown. Two are for fields in the Russian Provinces of West Siberia and Volga Ural, two are from different studies of US onshore fields by USGS, and one is for fields in Federal Offshore waters by MMS. The US studies are based on discovery years, while the West Siberia and Volga Ural studies are based on first year of production.

PGC Reserve Growth or Probable Resources Methodology

PGC adopts slightly different methods for reserve growth arising from discovered but unconfirmed vs. undiscovered pools in a known formation. The discovered portion comprised extensions to accumulations considered partially developed while the undiscovered portion is comprised of new pools within an existing field.

The discovered unconfirmed portion is imputed by first calculating potential rock volume based on geological, geophysical and engineering data; this volume is multiplied by a yield factor and by the probability of that accumulation exists The yield factor is calculated from the currently producing area of the field and from the same formation as the volume being evaluated. The yield factor is adjusted for possible variations in factors, such as lithology, thickness, porosity, permeability, hydrodynamic conditions of the formation, and relationships among gas, oil and water in it. The probability of existence of the accumulation is based on analog data from similar fields in the province.

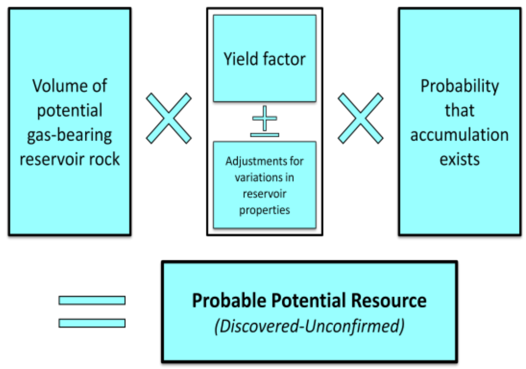

Figure 8: Methodology used by Potential Gas Committee in assessing reserve growth in partially developed accumulations in a known field.

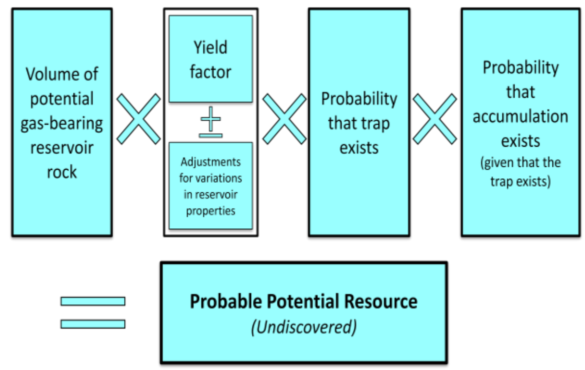

Figure 9: Methodology used by Potential Gas Committee in assessing reserve growth in undiscovered accumulations in a known field.

Undiscovered potential, because of limited engineering data, requires more geological and geophysical data interpretation for delineating new pools within existing fields. For example, a field in the discovered-unconfirmed category requires that the probability of the existence of a trap be estimated. These approaches are illustrated in Figure 8 and Figure 9.

The PGC captures uncertainty by asking each PGC assessor to consider three specific scenarios: a "Minimum", a "Maximum" and "Most Likely" natural gas volume. Each assessor imputes a *Minimum* based on his or her appraisal of the minimum number of traps that exist, the most marginal of source rock and reservoir conditions, a minimum reasonable yield factor and the fraction of traps that contain recoverable gas accumulations. Such conditions lead to a minimum (100% probability) of the resource. The *Most Likely* estimate is calculated by assuming the most reasonable values of these same factors. Similarly, the Maximum estimate is imputed by using the most favorable assumptions.

The PGC framework for determining Minimum, Most Likely and Maximum gas resource volumes is applied, with appropriate modifications, to CBM and the components of traditional resources other than conventional resources, namely tight and shale gas. It is also used for the Possible and Speculative categories. An illustration of Probable, Possible and Speculative resources is shown in Figure 10.

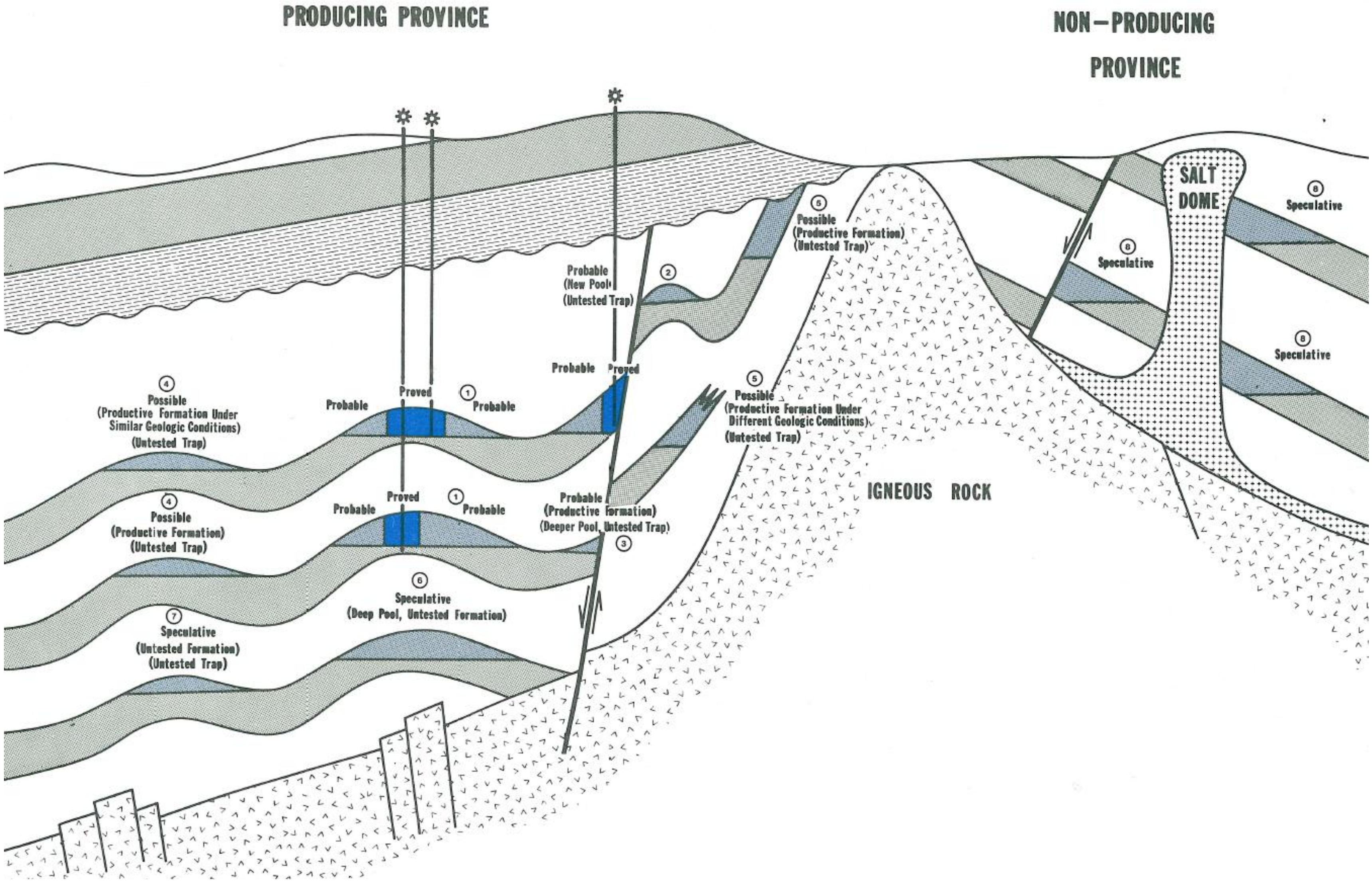

Figure 10: Resource categories assessed by the PGC are depicted in this figure. Here reserve growth is labeled "Probable"; and undiscovered resources are labeled "Possible" and "Speculative" based on the maturity of the play or trend. This figure has been reproduced from (Potential Gas Committee 1980).

NPC-2003 Methodology for Reserve Growth

In its 2003 report, NPC estimates the reserve growth for US, Canada, and Mexico. The methodology adopted was *"well cohort analysis"* developed by EEA[5]. The fundamental approach is to use historical data to determine the decline in recovery per well over time, as plays are developed and become increasingly mature. These well productivity declines are then extrapolated into the future, up to an estimated economic limit, to model the ultimate recovery from the play in question.

To conduct this analysis, EEA created a well data database indexed by estimated ultimate recovery (EUR) per well, location by basin, depth interval (e.g. 5,000 to 10,000 ft), field type (e.g. conventional, tight gas etc), discovery period of the field, and date of completion of the well. EUR per well, is the sum of cumulative production and its estimated reserves, is computed using a exponential decline curve with an economic cut-off based on well location and depth.

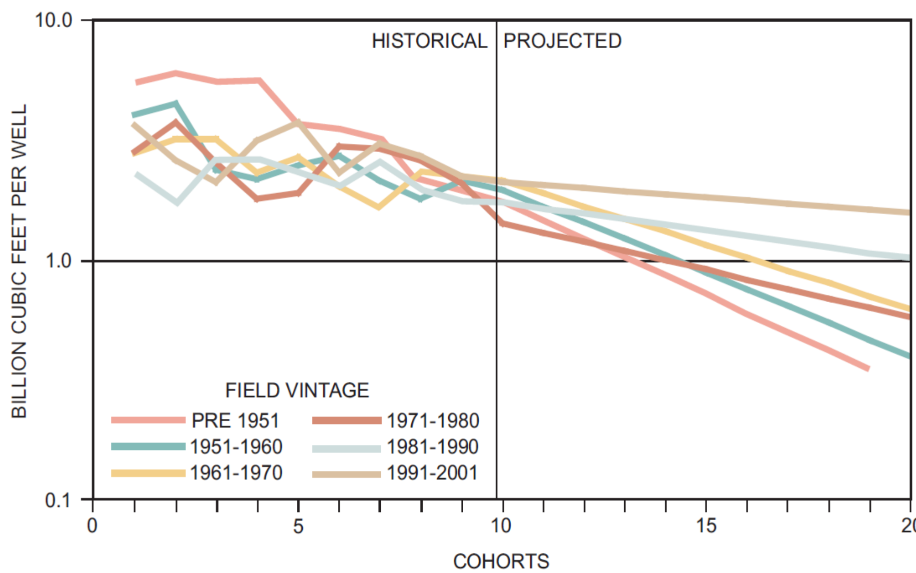

Figure 11: Graphs of a linear fit to average EUR/well in a given cohort of different groups of fields (Figure S2-80 from NPC report).

The database is partitioned into 10 cohorts for each field discovery period and each region. Cohorts are formed by partitioning wells into 10 groups by according to cardinal order of completion date, i.e. the first 10% wells constitute the first cohort.

An average EUR/well is computed for each cohort and a linear regression fit to average EUR/well as a function of time is used to extrapolate average growth percentages. Figure 11 shows an example. As stated earlier, an economic cut-off for EUR per well is imposed and, in addition, some ex-post subjective adjustments were made to insure that growth estimates

[5] Now part of ICF International

conform to the general pattern of EUR of the group of fields to which the wells belong. The average growth rate percentage is then multiplied by EIA reported proved reserves for each basin to arrive at an estimate of mean reserve growth. The NPC study does not report confidence intervals or other measures of uncertainty.

The NPC analysis just described incorporates several important assumptions : EUR/well completions decline as time progresses because producing reservoirs are drained and new reservoirs of poorer quality and thinner pools are exploited; new completions occur only as long as the EUR/per well is above the economic cut-off. In addition, personal judgments are used to choose decline curve slope. The NPC assumption about decline in EUR/well over time is similar to the USGS assumption about growth function for common fields. One expects the economic truncation point to change with technology improvements.

ICF Methodology for Reserve Growth

ICF uses EEA's analysis, which was developed for the 2003 NPC study, to estimate the mean reserve growth for US and Canada using the growth percentages.

For the rest of the world ICF uses 2000 World Assessment databases, available from the USGS. These databases include data for known volumes with and without growth for each assessment unit[6]. For each assessment unit, growth is constrained to be greater than 30% of existing reserves, but less than 50% of EUR[7].. Although somewhat arbitrary, these restrictions are imposed to correct for the fact that the USGS reserve growth estimates, which are based on US reserve growth analogs, are likely to be over-optimistic for many other parts of the world – for the reasons outlined earlier.

Assessment Methodology for Undiscovered Conventional Gas Resources

USGS Conventional Undiscovered Resource Assessment Methodology

In 1995 the USGS conducted a comprehensive survey of US oil and gas resources.. Oil, gas and natural gas liquids were assessed. At the core of this assessment are data that allows imputation of the number of deposits in an AU along with a deposit size distribution.. Data is provided at the play level.

Deposit size distributions are assumed to be truncated, shifted Pareto distribution (Houghton 1988):

[6] An assessment unit (AU) defined to be an element of a total petroleum system. An AU is conceptually similar to a play, but usually covers a larger geographic area and, in some instances may contain more than one play. Further discussion can be found in the section on USGS assessment methodology used in the 2000 World Assessment for undiscovered, technically recoverable, conventional gas resources.

[7] EUR, in this context, includes cumulative production, reserves, reserve growth and undiscovered technically recoverable resources.

$$f_Y(x) = \begin{cases} \dfrac{1}{1-f}\left(\dfrac{x-\gamma}{a}+1\right)^{-1-\frac{1}{b}}, & \gamma \le x \le x_{\max}, \\ 0, & \text{otherwise,} \end{cases} \tag{1.3}$$

Here γ is a minimum field size, a is a scale parameter and b is a shape parameter, f a truncation fraction and $x_{\max} = a(T^{-b}-1)+\gamma$. An example with $\alpha = e = 2.718$ and $y_m = 3$ is shown in Figure 12.

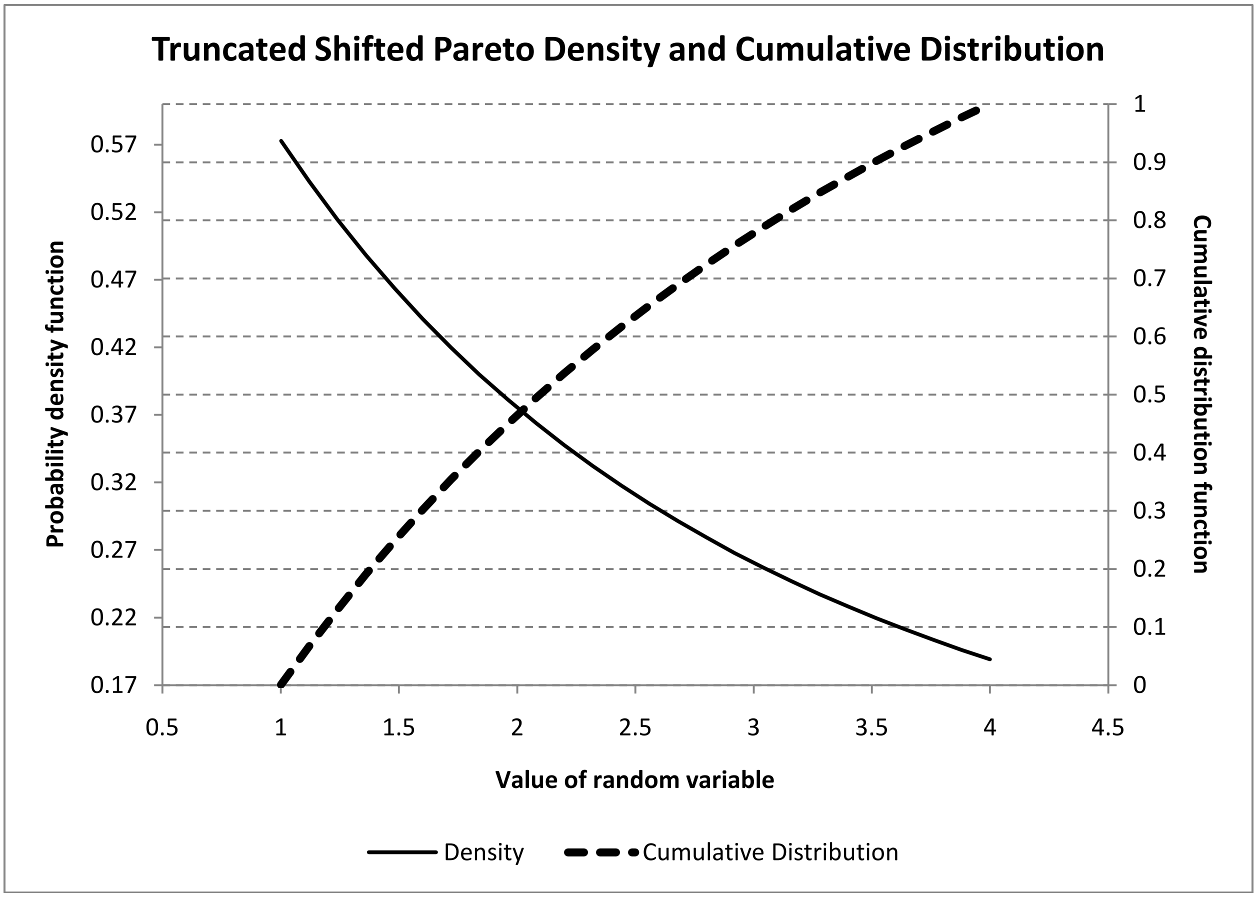

Figure 12: The truncated, shifted pareto distribution with $a = 5.817$, $b = 0.6$, $f = 0.5$, $\gamma = 1$ and $x_{\max} = 4$ is shown in this figure.

The distribution of the number of deposits in a play or AU, as well as the gas to oil ratio (GOR), is assigned a triangular distribution:

$$f_X(x) = \begin{cases} \dfrac{2(x-a)}{h^2 p}, & a \le x \le a+ph \\ \dfrac{2(a+h-x)}{h^2(1-p)}, & a+ph \le x \le a+h, \text{ and} \\ 0, & \text{otherwise} \end{cases} \tag{1.4}$$

Here $0 < p < 1$, $F_0=a$, $F_{100}=a+h$, and the modal value is $m=a+ph$. An example is shown in Figure 13.

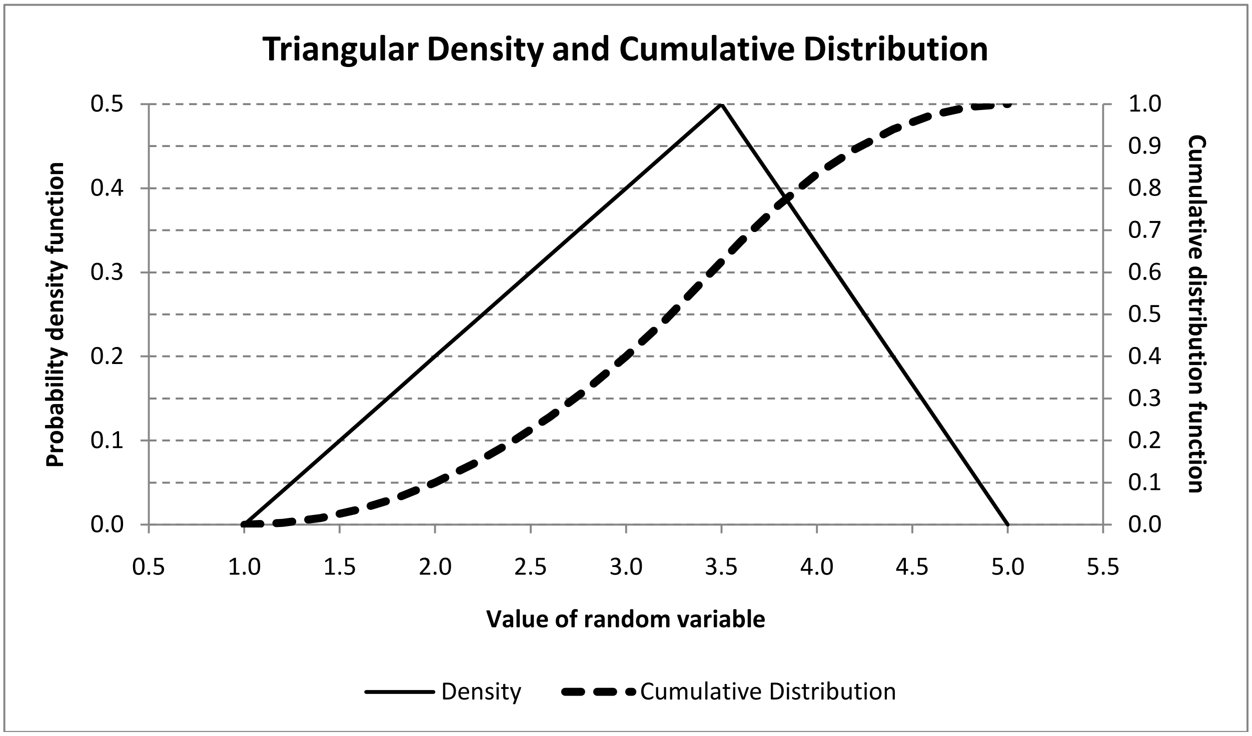

Figure 13: A triangular density function with a minimum of 1, a maximum of 5 and a modal value of 3.5 (a=1, h=4 and p=0.625.

Distributions of the number of accumulations, accumulation sizes and relevant coproducts are convolved by Monte Carlo simulation to arrive at petroleum deposit volume. Co-product ratios are used to compute NGL's, and associated gas volumes. This workflow is shown in Figure 14.

Each play is assigned to one of 66 provinces and basins. Basins are then aggregated to form eight regions; one for Alaska and seven for the L-48.

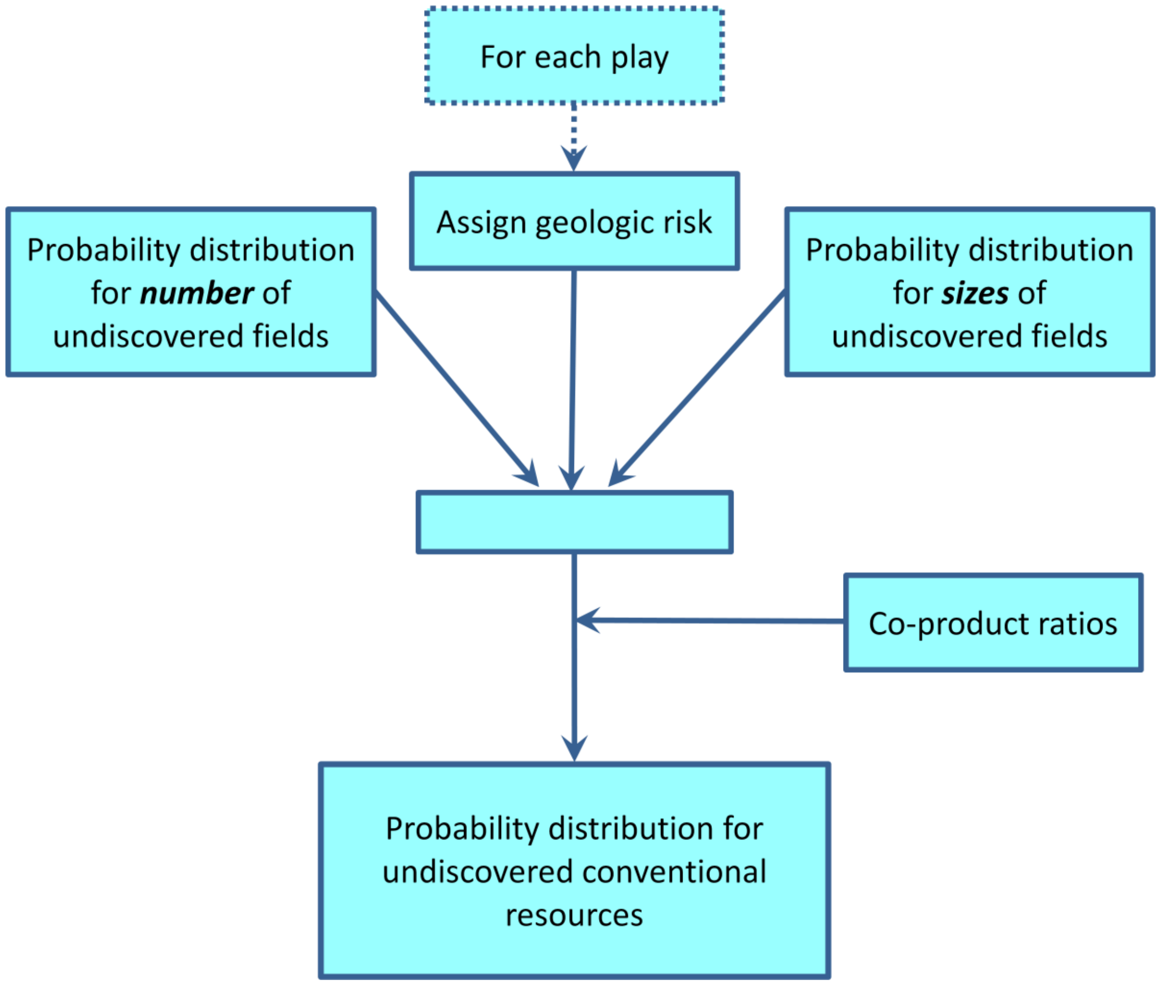

Figure 14: Flow diagram for USGS 1995 assessment procedure.

After the 1995-assessment, the USGS modified its methodology and labeled it the "Seventh Approximation" model[8]. There are four important changes. First, primary data is compiled at the assessment units (AU) level in place of play level. Emphasis is shifted from similarities in reservoir rock to petroleum fluid flows arising from a common source rock. A total petroleum system (TPS) is defined to be a collection of genetically related petroleum accumulations generated from the same pod or closely related pods of mature source rock. A TPS may contain only one AU or be further divided into several AUs to create more homogenous units.

[8] The name "Seventh Approximation" was chosen to indicate and affirm that this model for imputing resources is just an approximation, and the results of a resource assessment are subject to change with time.

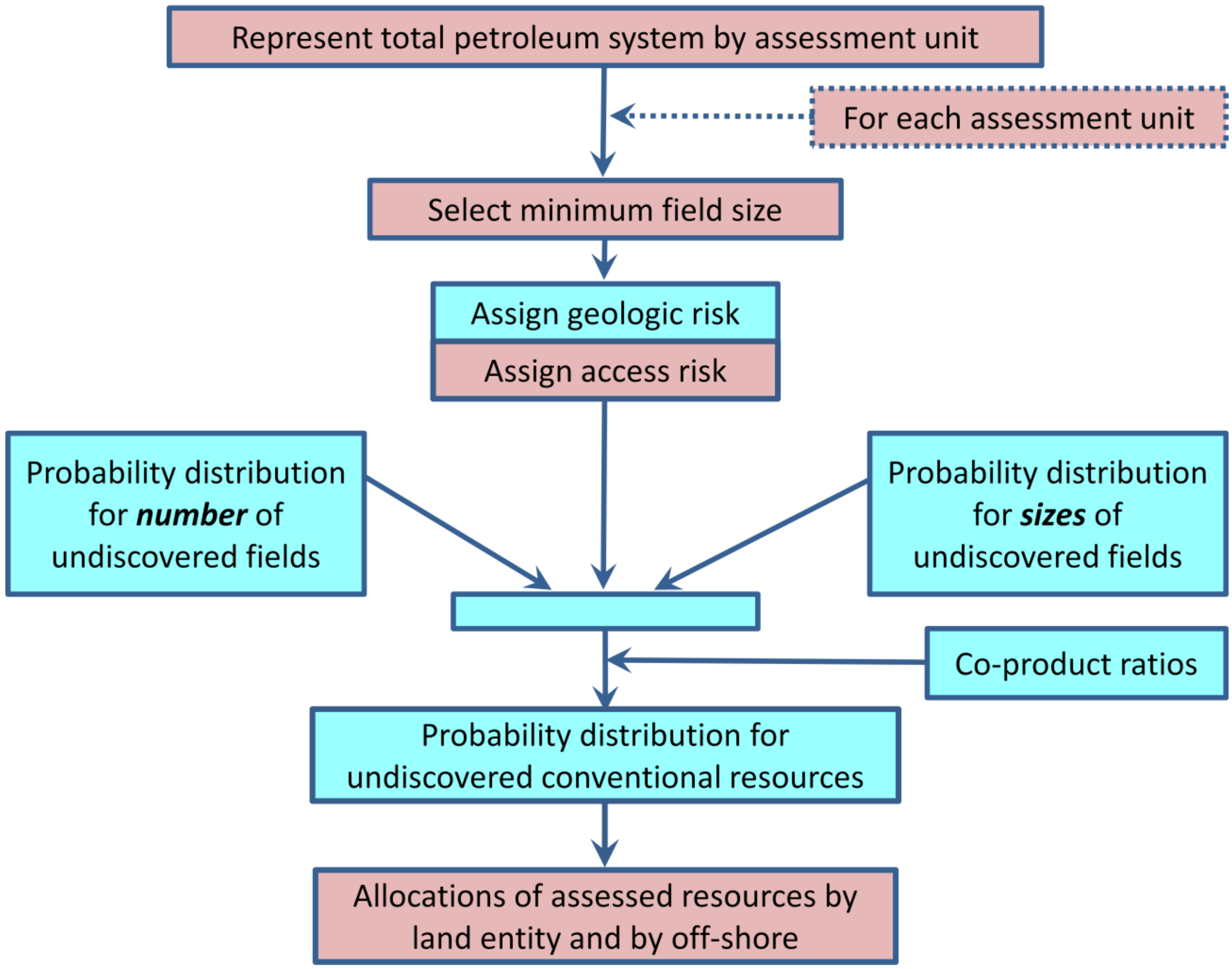

Figure 15: This figure shows the evolution from the 1995 assessment methodology to the current methodology (shown in pink) used by the USGS in its "Seventh Approximation" model for the assessment of conventional petroleum resources.

The second change restricts assessment to a 30-year or one generation time frame, which the USGS declares to be an assessment of potential additions to proved reserves and reserve growth vs. undiscovered technically recoverable resources. The philosophy is that current discovery history plays a key role in assessment while current discoveries depend on current engineering techniques and technologies which determine the quality of resources developed. But over long time durations (greater than 50 years) a dependence on today's conditions no longer pertains, hence an attempt to assess UTRR can have little claim to accuracy. This time horizon restriction is thus a restriction on the quality of resources included in the assessment. It manifests itself in defining a different minimum size for each AU by the assessor who has an intimate knowledge of the geology and production history of a given AU instead of a blanket cut-off of 6 Bcf or 1 MMBOE for all plays used in the 1995 assessment. Third, access risk -- the probability of developing a resource given various environmental or land-use restriction on various parcels of land—is assessed (Access risk is not appraised in the 1995 assessment). These modifications are highlighted in pink in Figure 15.

The fourth difference is replacement of a truncated, shifted Pareto field size distribution with a left shifted, right truncated lognormal distribution:

$$f_{LN,T}(y-\gamma|\mu,\sigma)=\begin{cases}\dfrac{1}{F_{LN}(T-\gamma)\sqrt{2\pi}\sigma(y-\gamma)}\exp\left[-\dfrac{1}{2}\left(\dfrac{\ln(y-\gamma)-\mu}{\sigma}\right)^2\right], & \gamma\leq y\leq T,\\ 0, & \text{otherwise}\end{cases} \tag{1.5}$$

Here $T=f_{001}=F_0$ is a right tail truncation point, $F_{LN}(x)$ is the lognormal cumulative distribution evaluated at T, $\gamma=f_{100}=F_{100}$ is the shift parameter and μ and σ are the mean and standard deviation for the normally distributed random variable $X=\ln(Y-\gamma)$. An example of the lognormal distribution is shown in Figure 16.

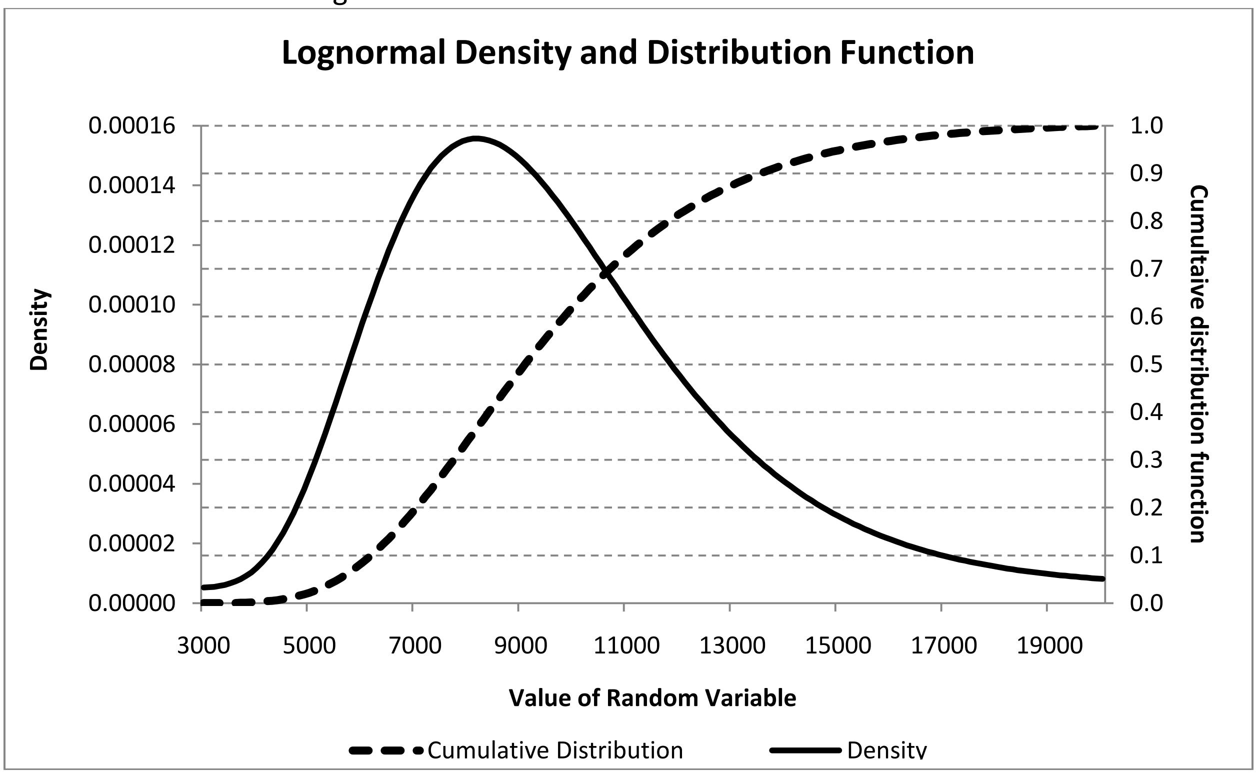

Figure 16: The density (solid line) and the cumulative distribution (dashed line) for the lognormal with μ=9, σ=0.35, γ=1000 and T=2000.

As in the 1995 assessment, the number of fields in an AU, the gas to oil ratio, and the natural gas liquids to gas ratio, are assigned triangular distributions. All are assumed to be mutually independent.

MMS Conventional Undiscovered Resource Assessment Methodology

Historically, the USGS had responsibility for resource assessments across the entire US. In 1982 the Minerals Management Service (MMS) was established and given responsibility for resource assessment activities in Federal offshore areas of the US. As a result, in order to get a complete projection of US oil and gas resources it is necessary to account for MMS resource projections for the outer continental shelf (offshore areas under Federal jurisdiction). In this section resource estimation methods used by the MMS in its 2006 assessment (Minerals Management Service 2009) of conventional oil and gas resources in Federal waters is described briefly.

The MMS assessment methodology rests on a comprehensive play-based approach to assessment of hydrocarbon potential. Their method is conceptually similar to the methodology used by USGS in its 1995 assessment. The assessment is carried out for four outer continental shelf (OCS) regions: Alaska, Atlantic, Gulf of Mexico and Pacific.

The MMS assesses crude oil, natural gas liquids (condensates) and natural gas that exist in conventional reservoirs and are producible with conventional recovery techniques. Crude oil and condensates are reported jointly as oil, while associated and non-associated natural gas is reported as gas. The MMS assessment does not include potentially large quantities of resources that may be recovered using enhanced recovery techniques from known and future fields, gas in geo-pressured brine, natural gas hydrates, and oil or gas that may exist in accumulations of insufficient quantity or quality to be currently producible using conventional techniques. The MMS appraises UTRR and, in addition, a second resource known as an undiscovered economically recoverable resource (UERR).

PGC Conventional Undiscovered Resource Assessment Methodology

PGC publishes a bi-annual report, which divides undiscovered resources into two categories: "Possible Resources" and "Speculative Resources," the former for plays with an established production and the latter for plays with no production history. The USGS also delineates plays/AU's by maturity in a similar fashion but does not distinguish possible and speculative resources. These resource categories are illustrated in Figure 10.

The PGC assessment procedure follows the same steps for Possible and Speculative Resources as shown for undiscovered Probable Resources in Figure 9. The difference is in the data available and the parameters emphasized in the course of projecting quantities needed for the calculation shown.

The number of untested traps in a productive formation must be assessed to appraise undiscovered Probable and Possible Resources. Possible Resources are located away from presently productive fields relative to Probable Resources. Thus the key difference between their assessments is the strength of their relationship with proved production data. The extension of a play or trend from a productive region to a relatively unexplored one allows for a reasonable geologic interpretation of the numbers and types of traps. Available geologic and geophysical data also helps with determining locations and sizes of traps. It is the careful evaluation of these data that allows reservoir volumes and yield factors to be determined Probabilities that traps and accumulations exist depends on a play or trend's maturity and available exploration data.

Estimation of Speculative Gas Resources requires that accumulations which may be found in untested sediments located in both producing and non-producing provinces be appraised.

Factors taken into account are sediment types, structural and stratigraphic relationships, tectonic history, and thermal maturity. Yield factors are developed using analogs, with adjustments for dissimilarities between the area under consideration and the analog. Probabilities of that accumulations and traps exist are generally grouped together. The estimator's judgment, while important in the assessment of all resources, plays an even greater role for Speculative Resources.

Again, PGC reports *Maximum*, *Minimum* and *Most Likely* or modal value of Possible and Speculative resources. These statistics are estimated by adjusting volume potential and yield factor according to the case, as discussed above in the sections on reserve growth and Probable resources. Resource potential projections are reported individually for each geologic province.

NPC Conventional Undiscovered Resource Assessment Methodology

The NPC conducted a comprehensive study of natural gas for North America in 2003. This study included a resource assessment based on the USGS 1995 assessment and more up to-date subsequent assessments by the USGS. Their play definitions and province boundaries followed closely the USGS US boundaries with some modifications, where a few basins were either broken down into smaller assessment units or grouped together into larger assessment units e.g. the USGS Bend Arch-Fort Worth Basin and Permian Basin were combined and called the Permian Basin in the NPC study. They used the Canadian Gas Potential Committee (CGPC) Report for Canada, the IHS Energy "Focus on Mexico" report and the USGS 2000 World Petroleum Assessment for Mexico.

NPC assembled industry and government experts and held workshops to examine and modify, if necessary, USGS mean resource estimates for key large plays. Conventional accumulations were assessed for all areas of North America. Unconventional accumulations were assessed for the U.S. and Canada onshore only.

The NPC study also chose to employ a size distribution other than Pareto or lognormal. They posit that it is unrealistic for proportions of smaller fields to decline as size decreases (as do lognormal distribution proportions), but argue at the same time that the Pareto distribution overestimates small field proportions. This argument leads them to adopt a "linear ratio distribution". Size class intervals are modeled as a geometric series with a common ratio of two[9]: Size class 1 contains fields in the size interval $S_1 = [0.1875, 0.375]$ Bcf; the kth size class is $S_k = 2^{k-1}S_1$, where $k = -2, \dots, 17$.

They create the linear ratio distribution for each play/AU in the following way: The number of fields in each size class interval is initially determined by multiplying the mean number of fields by size class proportions. These size class proportions are obtained from a lognormal size distribution. Then given the number of fields N_k in size class k, search for largest size class k^* which satisfies the inequality $N_{k^*} < 1.8N_{k^*+1}$. Then for size class $k = k^* - 7, \dots, k^*$, if the

[9] These size classes were originally defined by USGS and were adopted in the NPC study.

number of fields N_k, is less than a proportion of the number of fields in the next size class, $N_k < \alpha_k N_{k+1}$, increase the number of fields in class k by setting $N_k = \alpha_k N_{k+1}$, where the values of α_k are given in the table below.

k	k^*	k^*-1	k^*-2	k^*-3	k^*-4	k^*-5	k^*-6	k^*-7
α_k	1.8	1.7	1.6	1.5	1.4	1.3	1.2	1.1

An illustration of this modification is shown in Figure 17.

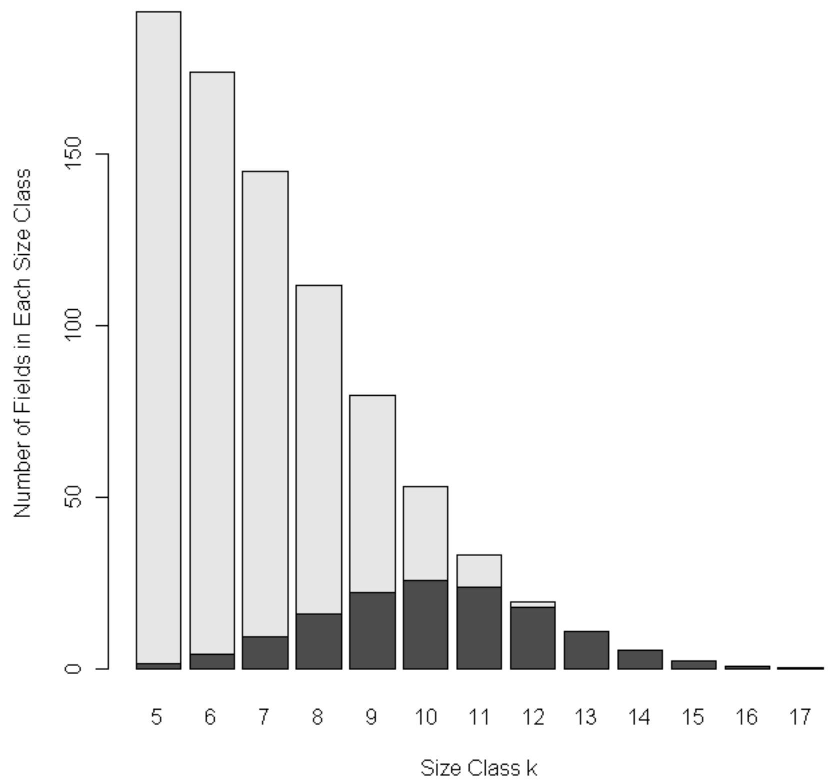

Figure 17: A comparison of a lognormal (black) and a linear ratio model (gray) for the size distribution with $k^* = 12$.

They also select a minimum field size for each play or AU. The number of fields in size classes smaller than the minimum field size is set to zero.

A key distinction between the USGS and the NPC study is that all NPC estimates published are point estimate unaccompanied by measures of uncertainty.

ICF Conventional Resource Assessment Methodology

ICF uses NPC estimates for US, Canada and Mexico. It uses the USGS input data for the rest of the world to construct its estimates using the linear ratio model with fixed $k^* = 12$, described in the previous section, as the size distribution. As with the NPC study, ICF only constructs point estimates and does not attempt to capture the uncertainty in such estimates.

Unconventional Resource Assessment Methodology

USGS Assessment Methodology for Continuous (Unconventional) Resources

The USGS chooses to refer to unconventional resources, such as tight gas, shale gas and CBM as *continuous resources*. This distinction is based on their perspective that the term "unconventional" emphasizes enhanced technologies needed for their extraction while "continuous" more accurately describes subsurface geological properties of tight gas, shale gas and CBM.

Along with modifying its methodology for assessing conventional resources in 2000, the USGS updated its approach to continuous resource assessment. This modification involved moving to the use of its FORSPAN model (Schmoker 1999). As with the "Seventh Approximation" model for conventional resource estimation, the FORSPAN model provides estimates of continuous resources with the potential to be added to reserves over the next 30 years. Limiting the assessment time frame to 30 years eliminates inclusion of accumulations that cannot be accessed in the foreseeable future due to physical or practical considerations e.g. gas hydrates in Antarctica or areas of a continuous formation with little prospect of economic wells. The last restriction limits the assessment to "sweet spots". Sweet spots are regions of continuous accumulation that have better production rates, and are the analogues of fields in conventional formations. However, the areal extent of a sweet spot is not, in general, as easy to define geologically as that of a conventional field, which has discrete boundaries.

An assessment of an unconventional accumulation requires that one know that it exists, where it is located and, in addition, know its production characteristics. At one end of the spectrum are well-developed AUs where these necessary characteristics are known with near certainty, while on the other end are accumulations with no development history. Sparsely developed AUs are somewhere in between these two extremes.

Typically, many reservoir variables are not known precisely, and so are assigned probability distributions. These probability distributions either capture the uncertainty in the knowledge of the value of the variable (e.g. the area of an AU) or represent a naturally occurring distribution (e.g. the *estimated ultimate recovery* (EUR)). The F0 (maximum), the F50 (median) and the F100 (minimum) are estimated for all input parameters that need to be represented by a probability distribution.

The first step in continuous accumulation assessment is the partitioning of an accumulation into petroleum-charged *cells* with areal dimensions determined by that accumulation's drainage area[10]. Cells extend vertically downward through strata being assessed. The potential for gas production in individual cells can vary significantly. To account for this, cells are partitioned into three assessment categories: cells that have been tested by drilling; cells that have not been tested by drilling; and t untested cells that have the potential to contribute to reserves in the forecast span. Only untested cells with potential are included in the assessment. Most of these cells are found in clusters within or close to sweet spots where production is favorable; therefore an important component of the assessment is to estimate the existence and number of such sweet spots.

Estimation of continuous resources at the AU level requires appraisal of the estimated ultimate recovery per cell in a sweet spot. This is accomplished, as shown in Figure 18, by first estimating a minimum EUR per cell from the AU's production history, or, in the absence of this data, from an analog. This minimum is effectively an economic cut-off. It is a consequence of appraisal of *geologic risk*--the probability that there is at least one un-tested cell with adequate charge, adequate source rock and adequate timing. An AU is also assigned an *access risk*—the probability that explorationists can conduct petroleum related activities in any portion of it during the forecast period. Regulatory restrictions are one evident roadblock. Then the distribution of the number of untested cells in the AU that contain recoverable resources, $N_{u.p}$, is computed according to the following formula: the ratio of the total AU area, A_T, to the area per cell, A_{cell}, by the percent of the total AU area that is untested, x_u, and the percent of the untested area with potential for economic production, $x_{u.p}$. Schematically

$$N_{u.p} = \frac{A_T}{A_{cell}} \times \frac{x_u}{100} \times \frac{x_{u.p}}{100}. \tag{1.6}$$

A_T, A_{cell}, x_u and $x_{u.p}$ are all mutually independent uncertain quantities. Next, the probability distribution for EUR per untested cell is based on reservoir-performance data, or based on an analog region for that AU. The co-product ratios of gas/oil or natural gas liquids/gas for oil-prone or gas-prone AUs are projected. These ratios allow the projection of relevant coproducts in a given AU.

Probability distributions for the addition to reserves of oil, gas and associated coproducts are obtained by convolving geologic and access risk, the number of untested cells having potential, $N_{u.p}$, the EUR per untested cell having potential, and co-product ratios.

The FORSPAN model is then used to generate probability distributions of total hydrocarbon resources in each AU. The EUR/cell is assigned a lognormal distribution. Areas, percentages, and coproduct ratios are assigned triangular distributions.

[10] Well spacing is determined by state regulations and may not correspond to drainage area chosen for an AU during the assessment.

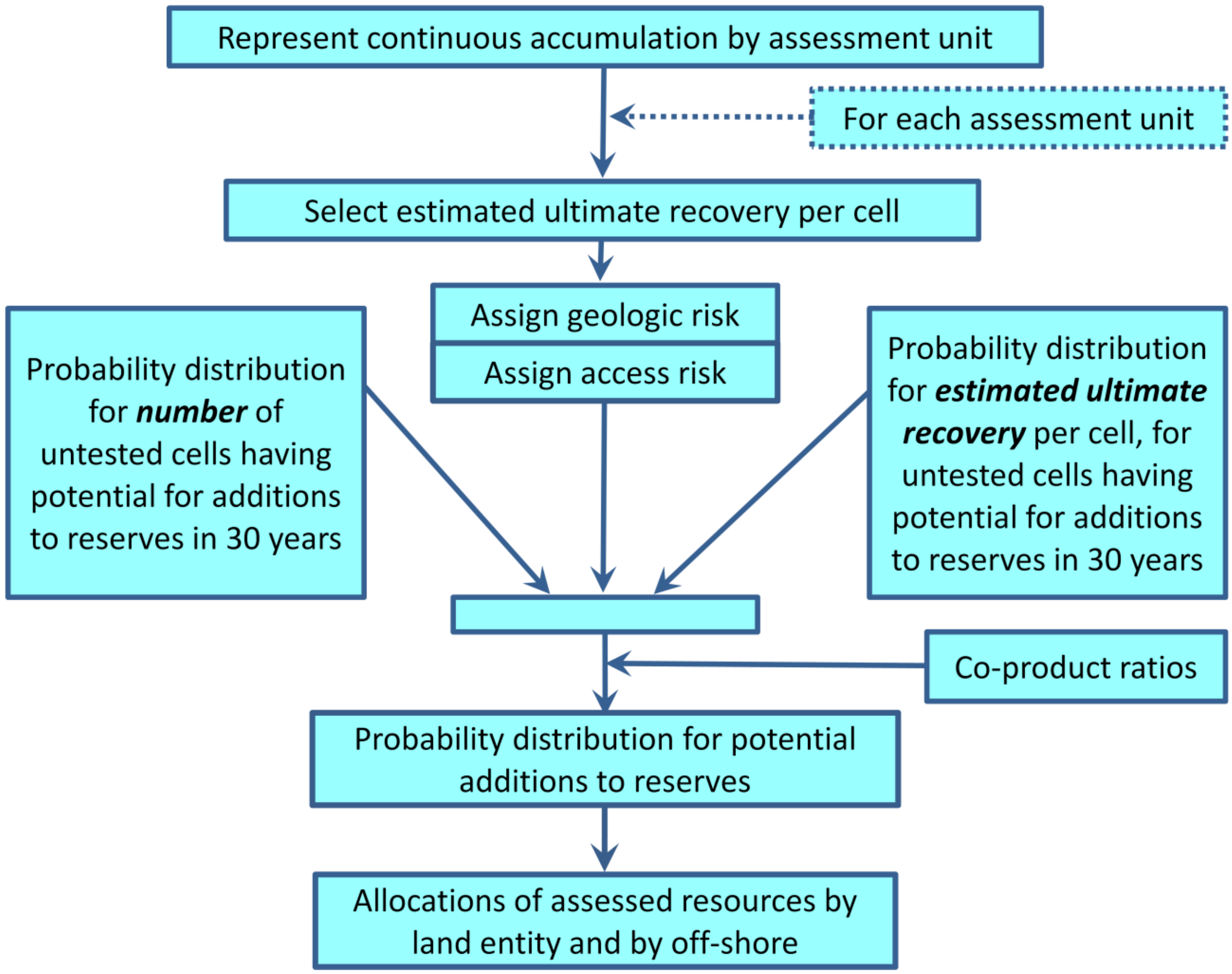

Figure 18: Simplified flow diagram emphasizing key steps of the FORSPAN assessment procedure for undiscovered continuous resources.

Once the key steps in the FORSPAN model are completed, a spreadsheet model, called ACCESS is used to calculate 5th, 50th and 95th percentiles, and the mean. A description of access can be found in (Crovelli 2005)

USGS's methodology follows a framework similar to conventional resources; a framework in which the analog of a conventional field is a sweet spot and that of a size distribution is EUR/cell. However, to some extent an unconventional gas resource could be considered more analogous to a hard rock mineral resource, where ore of variable quality is distributed over a certain area, and only some portions of the ore can be economically recovered – this being a function of thickness, concentration, etc. It is possible that some of the techniques used in mineral resource assessment could have a role to play in a more sophisticated approach to unconventional resource assessment.

PGC Unconventional Resource Assessment Methodology

PGC estimates unconventional resources, but groups them differently than the USGS and NPC. It divides resources as CBM and traditional, where traditional resource is the aggregate of conventional gas, tight gas and shale gas. In its 2008 report, it provides a separate tabulation for shale gas, but still includes it in the traditional resource tabulation. In this section, we briefly outline PGC's methodology for CBM.

Because of the difference in the occurrence of natural gas in coal seams compared to traditional resources, especially conventional gas, the PGC modifies both its resource category definitions and its assessment methodology for CBM. In the spirit of traditional resources, CBM resources are also categorized as Probable, Possible and Speculative. Probable resources occur under similar condition and in close proximity to proved reserves, and are estimated to be recoverable through extensions in current areas of production and development. Possible resources are future recoverable resources estimated to exist in known productive coal groups but outside of areas of established production, and development. There are extensive data available to the assessor on gas content and coal rank for these coal groups. And finally, Speculative resources are estimated recoverable resources outside of established production areas for which there are poor data on gas content and coal rank.

CBM resource estimation is done by multiplying gas-in-place by the fraction of gas in place which is recoverable. Both quantities need to be estimated by the assessor. Assessment of gas in place is derived from an analysis of seam thickness, areal distribution, depth and rank of coal, and gas desorption data. Thickness and areal distribution are determined from well log data and coal isopach maps. Coal rank and gas desorption is measured from actual samples or samples from analogs. From this, whenever possible, maps of coal rank and gas desorption are constructed to aid in the assessment. The recovery factor is again determined from production data either from the coal region or from an analog coal region.

NPC Unconventional Resource Assessment Methodology

The NPC 2003 study used the USGS NOGA studies as the basis for their unconventional resource numbers. These assessments were modified by experts in a workshop setting.

ICF Unconventional Resource Assessment Methodology

ICF maintains resource assessment numbers for unconventional gas. Their tight gas and CBM assessments were initially developed for the 2003 NPC study. However it has been conducting independent and current assessments for shale gas.

Shale thickness, its extent, total organic content, depth and maturity are key inputs for ICF's assessment protocol. These inputs are determined from data available in the public domain, such as published geologic maps by federal and state geological agencies, and industry maps and data.

ICF uses a county or township as the smallest unit for the analysis, usually 6×6 sq. miles. As with the USGS, this choice is driven by the desire to capture the large spatial variability in the productivity of a shale formation. Each township is assigned a drilling depth, shale thickness and total organic content (TOC). Gas-in-place (GIP) per ton is derived from these inputs and is multiplied by the total shale tonnage in the township to arrive at GIP for it. A risked GIP is estimated by taking into account geologic risk for areas outside of the core producing areas. This risked GIP is multiplied by a recovery factor to arrive at the estimate for the UTRR.

The recovery factor needs two inputs: estimated ultimate recovery (EUR) per well at the township level and the well spacing. Well spacing determines the GIP that a representative well is assumed to access. EUR per well is estimated from well production data using decline curve analysis, which is checked for consistency with recovery reported by operators. ICF uses 40 or 80 acre well spacing.

The assumed well spacing and the characteristics assumed for the well, especially the length of the horizontal section of the well, are significant sources of uncertainty for the estimates of recovery factor and UTRR.

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