DEPARTMENT OF MINES AND ENERGY

SOUTH AUSTRALIA

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A PROBABILISTIC METHOD FOR ESTIMATING GAS RESERVES

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A Probabilistic Method for Estimating Gas Reserves

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The Department's method for estimating and reporting gas reserves has been revised to include estimates of tight gas as well as providing more accurate estimates of conventionally recoverable gas reserves.

This has included a new method for volumetrically estimating reserves based on the permeability-thickness product (Kh). The traditioinal net pay method based on porosity cutoffs is not accurate, particularly for very heterogenous reservoirs. Probabilistic reporting methods have been adopted to better express the risk and uncertainty associated with estimating gas reserves. The probabilistic method can be used for material balance and decline curve reserve estimation methods as well as the volumtric method, thus allowing comparison of reserve estimates from different sources.

INTRODUCTION

As part of the Department's ongoing project on tight gas evaluation, and because it was necessary to improve methods of estimating conventional gas reserves in South Australia, a new method of determining OGIP and sales gas has been developed. This report forms Part 3 of the Tight Gas Evaluation project.

RESERVE DEFINITIONS

Reserve definitions of Proved, Probable and Possible were established by the SPE (and endorsed by the AAPG) in response to a need for reserve definitions that were uniform and meaningful to both technical persons within the industry and non technical users of reserve estimates (SPEE, 1988). These definitions have since gained wide acceptance, including Australia (Hillstead and Goode, 1989), but in practice would still appear too vague to give confidence in comparing estimates from different organisations. Also, global application is inconsistent, and in particular, Australia is the only country in the world that reports reserves in a combined Proved and Probable classification (Cronquist, 1991). Even so, in the Cooper Basin of South Australia, both the Department (SADME,1991) and the Cooper Basin Unit (SANTOS,1987) have independently established reserve mapping guide-lines which differ in several respects. Reserves can be calculated as single values in each category (deterministic) or as a continuum of reserve estimates with an associated probability (probabilistic). The SPE reserve definitions rejected the probabilistic approach as difficult to standardise, and favoured deterministic estimates in each category.

This decision has since been criticised, particularly for tight or fractured reservoirs (Caldwell and Heather, 1991), or where significant capital investment risk is associated with reserve estimates. The SPE has proposed an amendment to the reserve definitions of 'Proved', 'Probable' and 'Possible' to include a quantification of confidence levels for each category (SPE, 1991). The confidence levels associated with 'Proved', 'Proved and Probable' and 'Proved, Probable and Possible' categories are likely to be approximately 90%, 50% and 10% respectively, although Caldwell and Heather (1991) suggested there is consensus that the 75% confidence level equates to "reasonable certainty". The Department favours a probabilistic approach to gas reserve estimation because this method will evaluate both conventional and tight or fractured gas reservoirs, and advice provided to government and gas contract negotiators will contain some expression of the associated risk. The probabilistic approach can also be used for material balance and decline curve methods of reserve estimation, which are the dominant methods in gas fields with significant production history.

LIMITATIONS OF EXISTING DEPARTMENTAL RESERVE ESTIMATION METHODS

In the course of estimating gas reserves for all Cooper Basin gas fields in South Australia in the past 10 years, several limitations of the current methods have become apparent.

Gas in place mapping

Current OGIP mapping applies porosity cut-offs as indirect permeability cut-offs for pay determination from log analysis (usually corresponding to 0.1 md at reservoir conditions); this approach has been industry standard for at least 30 years, and is used to exclude 'tight' gas that is believed would not contribute to production and hence would not have any significant recovery. This means that current OGIP estimates are not strictly gas in place, but contain some expression of recovery. It would be technically more correct to map OGIP without porosity cut-offs, to accurately map all gas in place and apply recovery factors later. The resulting OGIP would then have some sort of geological reality, necessary for the Department's project of undiscovered reserves evaluation, and would also quantify 'tight' gas reserves. In addition, resource size comparisons are often made with OGIP estimates; differences may not reflect any true differences in the real OGIP estimates, but merely differences in pay cut-offs. However, the only meaningful basis for comparison of reserve estimates between say a producer and gas purchaser is sales gas. Mapping of true OGIP will possibly eliminate some OGIP differences and shift technical discussion to the problem of recovery.

Recovery Factors

Several instances are known of gas reservoirs tested by RFT showing significant depletion, even though they have porosities and DST flowrates below the commercial flow rate cutoff of Malavazos (1991a).

An example of this is given by a reservoir in a recent well in the Cooper Basin that flowed no gas to surface on test, but RFT measurements showed 14% depletion (average porosity was only 5.6%). This well thus has recoverable gas in the vicinity of the wellbore (via a nearby well with greater permeability), but under present guide-lines would have no pay mapped. The current industry standard method of estimating volumetric reserves is to use a porosity cutoff on a level-by-level basis to separate zones that contain recoverable gas from zones with no significant recovery. Porosity is used as indication of permeability (an insitu permeability of greater than 0.1 and is regarded as pay), and the `pay' thickness is combined with area to give a volumetric estimate of OGIP, although in fact this is really `recoverable' OGIP. The recovery factor is determined for the reservoir based on composition and average reservoir pressure (initial and at abandonment) and temperature. An implicit assumption of this method is that reservoir pressure will deplete to a uniform abandonment pressure. In heterogeneous gas reservoirs, initial flow rates of production wells can vary greatly, and abandonment reservoir pressure can also vary between wells, thus, recovery factors also vary on a well by well basis. This problem was addressed by Malavazos (1991b), who reviewed recovery from gas reservoirs, and concluded that recovery for gas reservoirs is critically dependent on two factors (assuming a depletion drive reservoir); the economic flow rate limit of the well at abandonment (and thus the abandonment pressure), and the Kh of the reservoir, regardless of the porosity magnitude or variation within the reservoir. Recovery is related to flowrate (both within the reservoir and from the reservoir to the wellbore), which in turn is related to Kh, and suggests that the industry standard approach of applying porosity/ permeability cut-offs on a level by level basis is fundamentally incorrect.

Stratigraphic Reservoirs

In the majority of instances Cooper basin gas reservoirs are not only limited by structural control (anticlines with gas water contacts) which are well defined by seismic data, but to varying degrees have stratigraphic limits. A problem occurs in determining where these limits are as in most cases only well control can be used, because the seismic data lacks sufficient resolution to map individual reservoirs. In the past, the department has taken the stratigraphic limit as half-way between the well where the reservoir is present and the well where it is absent. This may be acceptable for probable reserves, but is too optimistic for proved reserves, and conversely is too pessimistic for possible reserves.

PROBABILISTIC RESERVE MAPPING METHODS

Log Analysis

Porosity

For the calculation of porosity, a sonic log to porosity transform that is accurate to very low porosities is essential; this excludes the Porter-type algorithms currently still used by the Cooper Basin Unit, as previously discussed by Morton (1990). The porosity method described by Morton (1989) is used by the Department, and is considered accurate for low porosities. No porosity cut-offs are used, but a GR cutoff (usually 100API) is used to differentiate predominantly sandstone from predominantly shales.

Permeability

An algorithm that calculates permeability from porosity and gamma ray logs was developed using core permeability data and DST derived Kh; for the Permian Cooper Basin (see Figure 1).

For GR $\leq$ 20 API

Porosity < 0.090	$K = 10^{((30.7516 \times PHIT)-3.9225)}$
0.090 $\leq$ Porosity < 0.110	$K = 10^{((92.6951 \times PHIT)-9.4975)}$
Porosity $\geq$ 0.110	$K = 10^{((23.8742 \times PHIT)-1.9272)}$

For GR $\geq$ 60 API

Porosity < 0.108	$K = 10^{((69.6520 \times PHIT)-8.9200)}$
0.108 $\leq$ Porosity < 0.137	$K = 10^{((80.5963 \times PHIT)-10.1023)}$
Porosity $\geq$ 0.137 K =	$10^{((24.1200 \times PHIT)-2.3800)}$

K = permeability (md)
PHIT = log derived porosity (fraction)

For GR values between 20 and 60 API, permeability is linearly interpolated. Permeability values for each half foot data increment were multiplied by 0.5 and summed to give a Kh (permeability. feet value) for each reservoir in each well.

Figure 2 shows the results of applying this algorithm to a Cooper Basin gas field and comparing the results with actual Kh values from DSTs. The algorithm usually predicts Kh better than one order of magnitude but is apparently not particularly exact at low Kh values. However the data presented are biased for Kh below 0.2 md.ft. Only DSTs with sufficient flow to allow calculation of Kh were used, and any test interval of less than 0.2 md.ft would not have flowed unless fractures or considerable secondary porosity was present. The log analysis algorithm thus may provide a method of detecting the presence of fractures or secondary porosity. For recovery factor calculation, DST results are used, if available, in preference to log derived Kh. Figure 3 shows the empirical relationship between gas flowrate and Kh for an average Cooper Basin reservoir:

$$\text{Flowrate} = 0.3 \times (\text{Kh})^{0.6506}$$

Flowrate in mmcfd
Kh in md.ft.

This equation may be useful in predicting flowrate of sands that have not been tested (prior to perforation etc).

Water Saturation

Water saturation cut-offs are raised to 70% rather than the 50% currently used. Data to support this were derived from the Moomba Field, where gas/water relative permeability analyses were performed on 8 core plugs by Amdel Ltd for SANTOS. Permeability to gas and water was equal at between 59% Sw and 77% Sw, with an average of 67%. This also compares with water saturation cut-offs used in tight gas basins elsewhere (Satriana,1980, Spencer, 1989). Further analyses on other fields would assist in refining this cutoff, when available.

Mapping bulk reservoir volume

Bulk reservoir volume is mapped at three confidence levels, 90%, 50% and 10%, which reflect the uncertainty in reservoir limits. These guide-lines are formally summarised in the Appendix.

Structural Limits

Structural limits to a reservoir have traditionally been either a gas/water contact (GWC), a lowest known gas (LKG), highest known water (HKW) or, lowest closing contour (LCC). In the absence of a GWC, the 90% case would be taken as either the 90% fill factor (20% for the Cooper Basin), or if the LKG is lower than this, then 10% of the distance between the LKG and the 50% fill factor, and the 10% case as either the HKW or LCC (there is in the Cooper Basin a 10% chance that the field will be filled to spill). The 50% case would be the expected location of the GWC, perhaps from RFT pressure gradients, local structural fill factors (50% case, 70% fill for the Cooper Basin), or failing any indirect evidence of the location of the contact, be taken as half-way between the LKG and LCC/HKW. There is also an uncertainty associated with seismic mapping of structure, and this was statistically investigated using recent appraisal drilling results on the Moomba Field and the top Toolachee structure map. The difference between the predicted structural depth and the actual ranged from 24 feet high to 127 feet low, but is more likely to be low than high. In general for the Cooper Basin, there is a 10% chance the difference will be more than 10' high, a 50% chance it will be less than 30' low and a 90% chance that it will be less than 50' low, however if there is sufficient data this can be determined for each field. In practice, these data can be used to lower or raise the structural limits for each of the 90%, 50% and 10% cases.

Stratigraphic limits

Stratigraphic limits to a reservoir occur when one or more of the wells in a field do not contain the reservoir sand that occurs in other wells. The problem of where to map the reservoir limit can be solved simply by using a probabilistic approach; for a 90% probability case the limit would be 90% of the distance from the well where the reservoir is absent to the well where it is present; similarly for the 50% and 10% case. Figures 6 to 8 in the appendix summarise these guide-lines.

Recovery Factors

Reservoir abandonment is equated with the well flow rate at the point when the operating cost of the well exceeds the value of the gas produced. This is dependent on the reservoir pressure, the richness of the gas, and the number of reservoirs contributing to the total flowrate of the well. Malavazos (1991b) has produced, from tank model simulation of typical gas reservoirs in the Cooper Basin, a range of tables that assign recovery factors to each reservoir in each well based on Kh and well flowrate at reservoir abandonment. Additional tables have been produced for fracture stimulated wells. No recovery occurs for an unstimulated reservoir with a Kh less than 3 md.ft, and above kh of 100 to 1000 md.ft, recovery is close to the theoretical maximum 88%. However, most Cooper Basin reservoirs are strongly heterogeneous and thus these tables predict very variable recovery factors from within a single reservoir. In addition, wells with low Kh may have significant recovery if nearby wells have much larger Kh; the amount of recovery depending on where the boundary occurs between the high and low Kh part of the reservoir. The position of the boundary is similar to the stratigraphic limit problem outlined above, and Malavazos (1991b) has produced three tables for the 90%, 50% and 10% cases. Each of these tables are dependent on the relative magnitude of the high and low Kh wells. The following is an example (well abandonment flowrate = 0.3mmcfd, unstimulated wells):

Well 1 Kh = 3.0 md.ft
Well 2 kh = 30.0 md.ft

In isolation, well 1 has no recovery, but in conjunction with well 2 (assuming the Kh boundary is half-way between the two wells - 50% probability case), the recovery is 25%

well 1 recovery = 25%
well 2 recovery = 66%

This example is typical of the problems previously encountered with the traditional reserve mapping techniques; well 1 would not have flowed economically on DST, probably would not have had porosity greater than 8% (and hence no pay and no reserves would have been mapped), but would have most probably shown depletion on RFT measurements.

Recovery factors for Kh wells that have sufficiently high Kh to produce directly, may also have higher recoveries if there is an even higher Kh well nearby. In the example above if well 1 had a Kh of 300 md.ft instead of 3 md.ft, well 2 would have it's recovery increased from 66% to 77%. In practice, a table is constructed for each reservoir and recovery factors assigned to each well for the 90%, 50% and 10% cases (this includes both the Kh boundary uncertainty and the abandonment flowrate uncertainty), the results are weight averaged on hydrocarbon pore thickness to give a 90%, 50% and 10% confidence estimate on recovery for that reservoir. An additional set of recoveries can be generated assuming (where possible) wells are fracced, giving a quantitative estimate on recovery using current technology from tight gas reservoirs.

Monte Carlo simulation of field reserve estimates

Advantages of Monte Carlo methods

No matter what method (volumetric, production decline, or material balance) is used to provide a reserve estimate, there will always be an associated uncertainty, as all input parameters to the reserve calculation are not known exactly. Traditional volumetric reserve categories are a partial expression of this uncertainty, but the probabilistic methods offer advantages, the following of which were identified by Caldwell and Heather (1991):

1. Uncertainty is quantified and expressed as a continuous distribution.

2. Because uncertainty is quantified, reserve estimates are less prone to subjective interpretation of "reasonable certainty", and are thus likely to be more consistent.

3. The probabilistic highest confidence category (90% confidence), is a defensible and consistent

conservative estimate. The traditional approach in effect multiplies the "most likely" estimates for each of the parameters in the reserve equation to give a "proved and probable" reserve estimate. If these parameters are a normal distribution, the result will be an estimate in probability terms at 50% confidence. If these distributions are not normally distributed (they usually are skewed) the resultant traditional "proved and probable" estimate is unpredictably more or less than 50% confidence.

4. Future reserve estimate revisions should be orderly and smooth, without sudden revisions up or down early in the life of a field, as is often the case with deterministic estimates.

The following are additional advantages identified - particularly for the South Australian gas fields:

1. Monte Carlo methods can also be used for engineering based reserve estimation methods (material balance and production decline) and provide a basis for comparison with the volumetric method. Previously, engineering methods provided only a single estimate, usually taken as a proved estimate.

2. In multi-reservoir fields or multi-field basins, Monte Carlo methods are the only statistically correct way to sum many individual conservative estimates.

3. Deterministic volumetric estimates from other sources can be compared with the SADME probabilistic estimate, and the confidence in other estimates can be quantified.

4. The "risk" of a project can be clearly quantified, and is intelligible to non-petroleum industry users of reserve estimates

5. All parameters used in the reserve calculation can be assigned some variability, and those most important for the final reserve estimate identified and highlighted. The traditional volumetric reserve categories only express uncertainty in bulk reservoir volume, while other parameters, particularly recovery factors, are held constant.

Principles of Monte Carlo simulation

Variables in the reserves equation which are not known with certainty, could be assigned a range of values between likely maximum and minimum values. The reserves equation could then be calculated using these extreme values to give the range in possible values of reserves. This would be of limited use however, as these extreme values are by definition of low probability, and there is no expression of what is considered the most likely estimate. Rather than use extreme values, mean or most likely values for each variable could be used to give an estimate of reserves. This is essentially what is done in the conventional deterministic "Proved and Probable" method of reserves calculation, but in fact the resulting estimate of reserves is not the most likely or mean estimate of reserves, unless all the variables are normally distributed. This is rarely the case as most variables are skewed distributions. During a Monte Carlo simulation, each variable distribution is sampled and the resultant values used to calculate one estimate of the reserves. This process is repeated many times (perhaps 10000 times to ensure convergence) and the range of reserve estimates can be presented as a frequency and probability distribution. Figure 3 summarises this process. A recent advance in use of the Monte Carlo simulation process has been the development of "Latin Hypercube" stratified sampling, which will ensure that the entire range of each variable is sampled with fewer iterations (usually only 1000 iterations are necessary).

Cooper Basin gas fields typically have multiple stacked reservoirs. If each reservoir were simulated individually, and estimates of reserves given at 90% confidence ("Proven"), these 90% confidence estimates cannot be simply summed to give a 90% confidence estimate for the field - the result would in fact be much more conservative (more like 99% confidence). Similarly, summing 10% confidence (or "Proved, Probable and Possible") estimates would also be incorrect and result in optimistic estimates for possibles for the field. In simple terms this means that in a multi-reservoir field, we are unlikely to be unlucky in all reservoirs simultaneously for the conservative estimate (after all the 90% confidence level really means that in 9 times out of 10 the reserves will be greater than the stated value). The only correct way is to also Monte Carlo simulate the total for the field. If the total reserves for the Cooper Basin is required, this problem becomes even more serious, as there are approximately 800 pools in the Cooper Basin in South Australia. This problem has not previously been considered for the Cooper Basin, but applies to traditional methods of reserve calculations as well as Monte Carlo methods, and if not considered is likely to result in inconsistently pessimistic field or basin totals.

Volumetric OGIP and Sales gas estimates using Monte Carlo simulation.

Volumetric reserves estimates are calculated from a combination of the following factors:

<u>Porosity</u> is modelled using a normal distribution, with a mean determined from the hydrocarbon pore thickness weighted average porosity from log analysis, with standard deviation of 0.5 porosity units. This latter value is considered the possible error in empirical log porosity calibrated on overburden core porosity.

<u>Water Saturation</u> is modelled using a truncated normal distribution, with the mean determined from the hydrocarbon pore thickness weighted average water saturation from log analysis, with standard deviation of 5%, and limited between 70% Sw (which is the Sw pay cutoff), and either 10%, 20% or 40% as a lower limit depending of the magnitude of the average water saturation.

<u>Gas Expansion Factor (1/Bg)</u> is modelled as a truncated normal distribution, with the mean as determined from reservoir composition, pressure, and temperature data. A standard deviation of 2 is assumed, and the range is restricted to about 10 above and below the average. This magnitude of variation is based on data collated over a number of years in closely related Cooper Basin reservoirs, where several sets of data were acquired and interpreted.

<u>Shrinkage Factor</u> is determined from similar data to the 1/Bg factor, and is a truncated normal distribution with a standard deviation of 0.02, and restricted to a

range ± 1 standard deviation.

Bulk Reservoir Volume is modelled using an irregular cumulative probability distribution, where estimates of the bulk reservoir volume are given at the 90%, 50% and 10% confidence levels.

Recovery Factor is modelled as an irregular cumulative probability distribution, with estimates at the 90%, 50% and 10% confidence levels determined from the method outlined in section 4.3 above.

The results of applying this method to a known gas field are as follows (reserves in M^3x10^6):

	CONFIDENCE LEVEL		
	90%	50%	10%
SALES GAS	2600	3600	5100
OGIP17300	21000	24600	

The previous Proved and Probable sales gas estimate for this field was only 1800 M^3x10^6, and the OGIP estimate was 3300 M^3x10^6. This field contains multiple stacked reservoirs, which if the 90% estimates are added arithmetically, total 1100 M^3x10^6 - comparable with the traditional proved and probable estimate. The new method has also mapped much more gas-in-place than previously, indicating that this field contains considerable tight gas which currently only has an average 15% recovery factor. Thus, this field may be a good candidate for additional fraccing to increase the overall recovery factor.

Production Decline Sales Gas estimates using Monte Carlo simulation

The following factors are used to estimate sales gas reserves from a graph of the decline of daily raw gas production rate versus cumulative raw gas produced (the Department's PEPS-SA database can provide these graphs at call).

Slope of decline (daily production rate/cumulative production) is modelled by a triangular distribution with three cases; minimum, most likely and maximum. This needs to reflect possible future scenarios such as sudden production rate declines due to water breakthrough, tight gas influx etc.

Latest production rate can show recent fluctuations that may be reservoir related (e.g. water breakthrough), and this is modelled using a triangular distribution with minimum, most likely and maximum cases.

Future Compression is modelled as a triangular distribution, with minimum, most likely and maximum cases to reflect future stages of compression, which depends on the amount of existing compression.

Shrinkage is modelled as above for the volumetric case.

Recoverable gas to date is taken as a constant, with no significant error.

Economic limit of the daily flow rate per average well is modelled using a cumulative distribution, with 90%, 50% and 10% confidence cases. For fields with less than 5 wells, these are 0.5, 0.3 and 0.2 mmcfd respectively. For fields with greater than 5 wells, the limits are 0.2, 0.1, 0.07 mmcfd respectively per well.

An example of this method on a known gas field, with comparison with the volumetric estimate is as follows (Reserves in M^3x10^6):

	CONFIDENCE LEVEL		
	90%	50%	10%
SALES GAS (PRODUCTION DECLINE)	1700	1800	1900
SALES GAS (VOLUMETRIC)	1300	1700	2100

These estimates are in good agreement, the production decline method showing a much narrower range (and thus higher confidence) due to the large amount of production data available for this field. The previous traditional proved and probable sales gas estimate for this field was 2000 M^3x10^6.

Material Balance OGIP estimates using Monte Carlo simulation

Material balance estimates using Monte Carlo simulation are relatively simple if there has been a large amount of production, the only variable being the slope of the decline of P/Z versus cumulative production. A triangular distribution is used, with maximum, most likely and minimum estimates. Again if tight gas influx is suspected, this should be accounted for in interpreting the decline slope, but the resulting estimates will all be conservative. If a strong water drive is suspected, then an estimate of OGIP will only be obtained if there is sufficient early pressure data, and the resulting OGIP estimates may be of a greater range than for a non-water drive field. If there has been little production, other factors such as measurement errors on pressure and gas composition need to be accounted for.

An example of this method on a known gas field, with comparison with the volumetric estimate is as follows (OGIP reserves in M^3x10^6):

	CONFIDENCE LEVEL		
	90%	50%	10%
OGIP (MATERIAL BALANCE)	3200	3400	3600
OGIP (VOLUMETRIC)	2800	3450	4100

Again, these estimates are in good agreement, the material balance method showing a much narrower range (and thus higher confidence) due to the large amount of production data available for this field. The previous traditional proved and probable OGIP estimate for this field was 3000 M^3x10^6.

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APPENDIX

SADME RESERVE MAPPING GUIDE-LINES REVISED: October,1991

1. GENERAL MAPPING GUIDE-LINES

Independence of judgement is encouraged in estimating reserves. However, where there is deviation from these guide-lines, this must be supported by appropriate data and documented.

1.1 Reservoir Mapping

1.1.1 Reservoirs should be mapped individually. A reservoir (pool) is regarded as distinct from others if separated by a correlatable shale or coal over the entire area of the pool.

1.1.2 Subunits should be numbered with the lowest number at the base, and preceded by a letter indicating the formation. Subunits may be subdivided into base A top B pools if necessary.

1.1.3 Two or more reservoirs should not be regarded as a single pool unless they have been shown to correlate to a single reservoir in any other well on the same structure, or they have been proven by other means (RFT, DST etc) to have a common contact.

1.1.4 Contouring will honour well control and the geological model. A contour interval should be chosen to reasonably model the well data.

1.2 Structure Maps

1.2.1 Seismic maps should be checked to ensure that:

- all wells drilled and seismic lines recorded to date are included
- formation tops used are correct
- seismic interpretation is geologically consistent
- surveyed elevations and locations are used

1.2.2 Structure maps for top reservoir should be phantomed down or up from the nearest seismic horizon. It is not normally necessary to construct structure maps for individual sands unless there are significant thickness variations across a field.

1.2.3 Where possible SADME derived seismic interpretations should be used.

1.3 Reservoir Identification

1.3.1 A reservoir is defined as any geological unit in a well that contains movable hydrocarbons,and has measurable permeability or is naturally fractured.

1.3.2 All available logs, RFTs, DSTS, PLTs and production tests must be compiled to identify potential reservoirs.

1.3.3 In the case of a gas reservoir, GTS @ RTSM is only acceptable provided FFP > IFP and there is no formation water recovery.

1.4 Water Resistivity

1.4.1 All production, LET and DST data should be compiled and Stiff Diagrams constructed to validate water samples, and resistivities corrected for water of condensation and mud contamination.

1.4.2 The maximum corrected water resistivity should be used as an initial value for log analysis.

1.4.3 Water saturations in free water zones should be 80% to 100%, and in hydrocarbon zones 10% to 70%. If this is not the case, the apparent water resistivity should be modified.

1.5 Log Data

1.5.1 All digitized logs should be checked to ensure that:

- Surveyed locations and KB elevations are correct
- all relevant log data has been digitized, and correctly identified on headers (particularly for resistivity logs)
- digitizing quality is acceptable
- scales have been correctly calibrated
- log traces are correctly depth matched

1.5.2 Core porosity and permeability should be compared with log derived porosity and permeability and the latter adjusted if necessary. Ambient core porosity should be multiplied by a correction factor (for the Cooper Basin this is 0.95) to convert to overburden conditions.

1.5.3 Minimum pay thickness is one foot.

1.5.4 Logs should be corrected for edge effects as necessary.

1.5.5 Each reservoir in each well (including any plugged and abandoned well) is to be evaluated for:

- average porosity
- average water saturation
- net pay and net sand thickness
- total Kh, taking care to exclude edge effects and water zones

1.5.6 If the reservoir includes impermeable barriers (e.g. shales), the Kh for each permeable part should not be added together. The maximum of each part should be used.

1.5.7 Kh for each sand is to be modified based on DST or production test derived Kh. If the DST or production test includes more than one reservoir, Kh for each reservoir will be modified by multiplying the log derived Kh for each reservoir by the total Kh derived form test data divided by the total log derived Kh for the zones tested.

1.5.8 Net pay cut-offs are porosity > 0%, and SW < 70%.

1.6 Recovery Factors

1.6.1 Recovery factors for conventional gas reservoirs will be determined from a consideration of the corrected Kh of the reservoir, the minimum economic flow rate for a well on the field, and any fracture treatments of wells.

1.6.2 Recovery factors are first assigned to wells with sufficiently high Kh to be "Direct Producers" (i.e. they have a flow rate higher than the minimum economic flow rate cutoff). Fracced wells are assigned a higher recovery factor depending on amount of negative skin.

1.6.3 Wells with insufficient Kh to have recovery on their own (i.e. flowed on test at less than the cutoff) are designated "Indirect Producers", and may be assigned a recovery based on the Kh ratio of the nearest wells . Recovery is assigned to the Indirect Producer depending on the magnitude of the Kh of the Direct Producer. As the position of the boundary between the good Kh and poor Kh well is unknown, the tables have 3 probability cases.

1.6.4 All relationships between wells will need to be checked, and where two or more Direct Producer wells exist, indirect recovery factors are also calculated and the larger taken.

1.6.5 In determining recovery factors, consideration should also be given to future development scenarios - such as additional perforations, or if any currently unfracced wells that could be economically fracced.

1.6.6 These recovery factors assume conventional gas depletion drive reservoirs only. Naturally fractured reservoirs or reservoirs with a water drive will require modification of these techniques.

1.6.7 For oil reservoirs, oil in place estimates will be converted to conventional recoverable oil and enhanced recoverable oil reserves using relevant recovery factors.

2.0 DEFINITION OF RESERVE CATEGORIES

Reserve categories follow SPE reserve definitions, and are stated at three levels of confidence: 90%, 50% and 10%. These correspond to the old reserve categories of Proved, Proved and Probable and Proved, Probable and Possible. Reserve estimates for each pool are derived using Monte Carlo simulation, combining distributions of average porosity, average water saturation, formation volume factor, bulk reservoir volume, shrinkage factor, and average recovery factor. Estimates of more than 1 pool or field cannot be arithmetically added together, but must be independently simulated using Monte Carlo techniques.

2.1 90% Confidence level

A reserve estimate at this level of confidence means that it is believed, considering all data available at the time of the estimate, that ultimately there is a 90% chance that the reserves of the basin, field or pool will be more than the estimate, or a 10% chance that they will be less. This level of confidence is considered appropriate for gas supply contracts and infrastructure planning.

Guidelines for mapping reserves at 90% confidence are:

2.1.1 Field limit will be the GWC, or if only an LKG has been identified, the higher of the 90% case fill factor (20% fill for the Cooper Basin), and the 10% of the distance between the LKG and the 50% case fill factor.

2.1.2 Where the mapped LKG (or GWC) is more than 800m from any well with pay, the LKG (or GWC) will be raised to allow for errors in seismic mapping on flanks of the structure. This will be determined from previous appraisal drilling data, or if not available, for Cooper basin fields should be raised 50 feet.

2.1.3 Where reservoirs are absent in some wells for a pool, OGIP should only be mapped to 10% of the distance towards the 'absent well'.

2.1.4 If log analysis indicates marginally wet wells above the LKG (or GWC), the net pay will be used for mapping OGIP.

2.1.5 Recovery factors should reflect the 90% case for the minimum well flowrate cutoff for the field, and assume Kh boundaries occur at 10% of the distance to the Indirect Producer.

2.2 50% Confidence level

A reserve estimate at this level of confidence means that it is believed, considering all data available at the time of the estimate, that ultimately there is a 50% chance that the reserves of the basin, field or pool will be more or less than the estimate. This level of confidence is the 'most likely' estimate of the actual size of the basin, field or pool.

Guidelines for mapping reserves at 50% confidence are:

2.2.1 Field limit will be the most likely GWC level, either by drill stem test, log analysis, RFT pressure gradients or basin average fill factors (for Cooper Basin gas fields this is about 70% fill), for failing any of these, half way between the LKG and HKW or LCC.

2.2.2 Where the mapped GWC is more than 800m from any well with pay, the GWC will be raised to allow for errors in seismic mapping on flanks of the structure. This will be determined from previous appraisal drilling data, or if not available, for Cooper basin fields should be raised 30 feet.

2.2.3 Where reservoirs are absent in some wells for a pool, OGIP should be mapped to 50% of the distance between the wells.

2.2.4 If log analysis indicates marginally wet wells above the GWC, the net sand will be used for mapping OGIP.

2.2.5 Recovery factors should reflect the 50% case for the minimum well flowrate cutoff for the field, and assume Kh boundaries occur at 50% of the distance to the Indirect Producer.

2.3 10% Confidence Level

Guidelines for mapping reserves at 10% confidence are:

2.3.1 Field limit will, in the absence of a definite GWC, be the higher of the HKW or the LCC. For the Cooper Basin, there is a 10% chance fields will be filled to spill.

2.3.2 Where the mapped LCC, HKW or GWC is more than 800m from any well with pay, the GWC will be lowered to allow for errors in seismic mapping on flanks of the structure. This will be determined from previous appraisal drilling data, or if not available, for Cooper basin fields should be lowered 10 feet.

2.3.3 Where reservoirs are absent in some wells for a pool, OGIP should be mapped to 90% of the distance towards the 'absent well'.

2.3.4 If log analysis indicates marginally wet wells above the GWC, the net sand will be used for mapping OGIP.

2.3.5 Recovery factors should reflect the 10% case for the minimum well flowrate cutoff for the field, and assume Kh boundaries occur at 90% of the distance to the Indirect Producer.

TABLES adapted from Malavazos (1991b) for estimating recovery factors from Kh

F03668.JGM

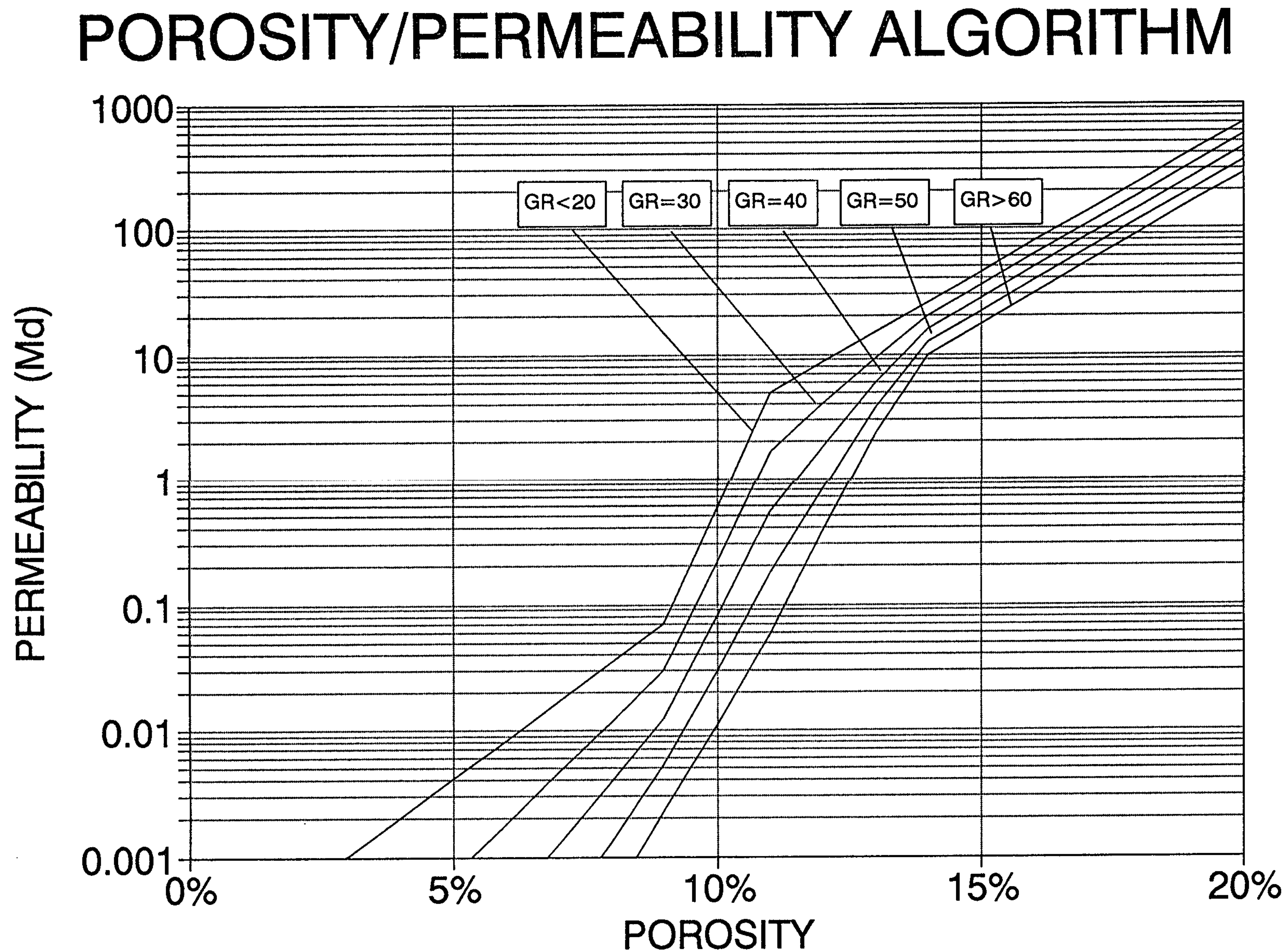

Figure.....1
SADME S22590

54G7

Kh COMPARISONS

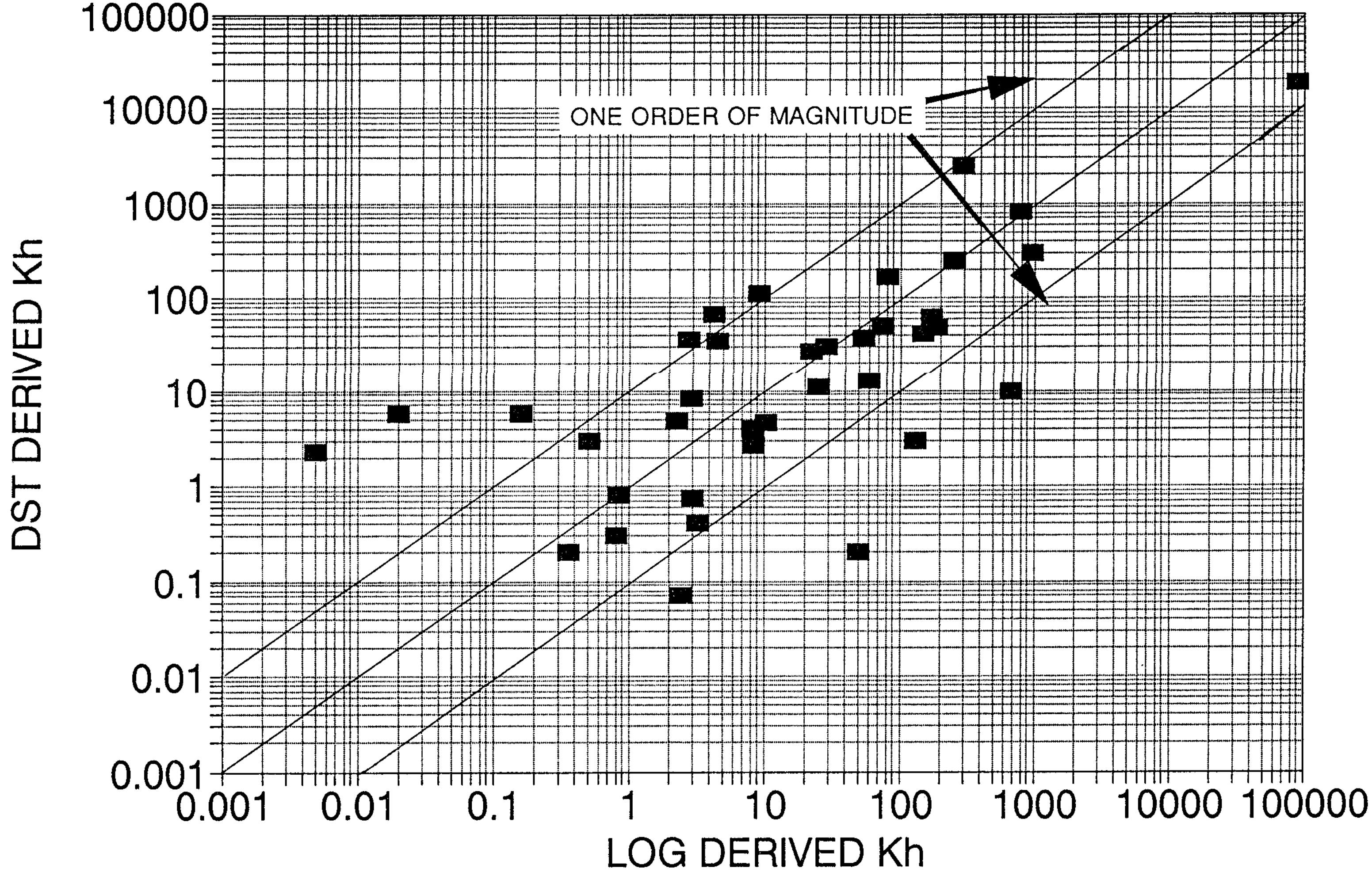

Figure 2
SADME S 22508

Flowrate vs Kh

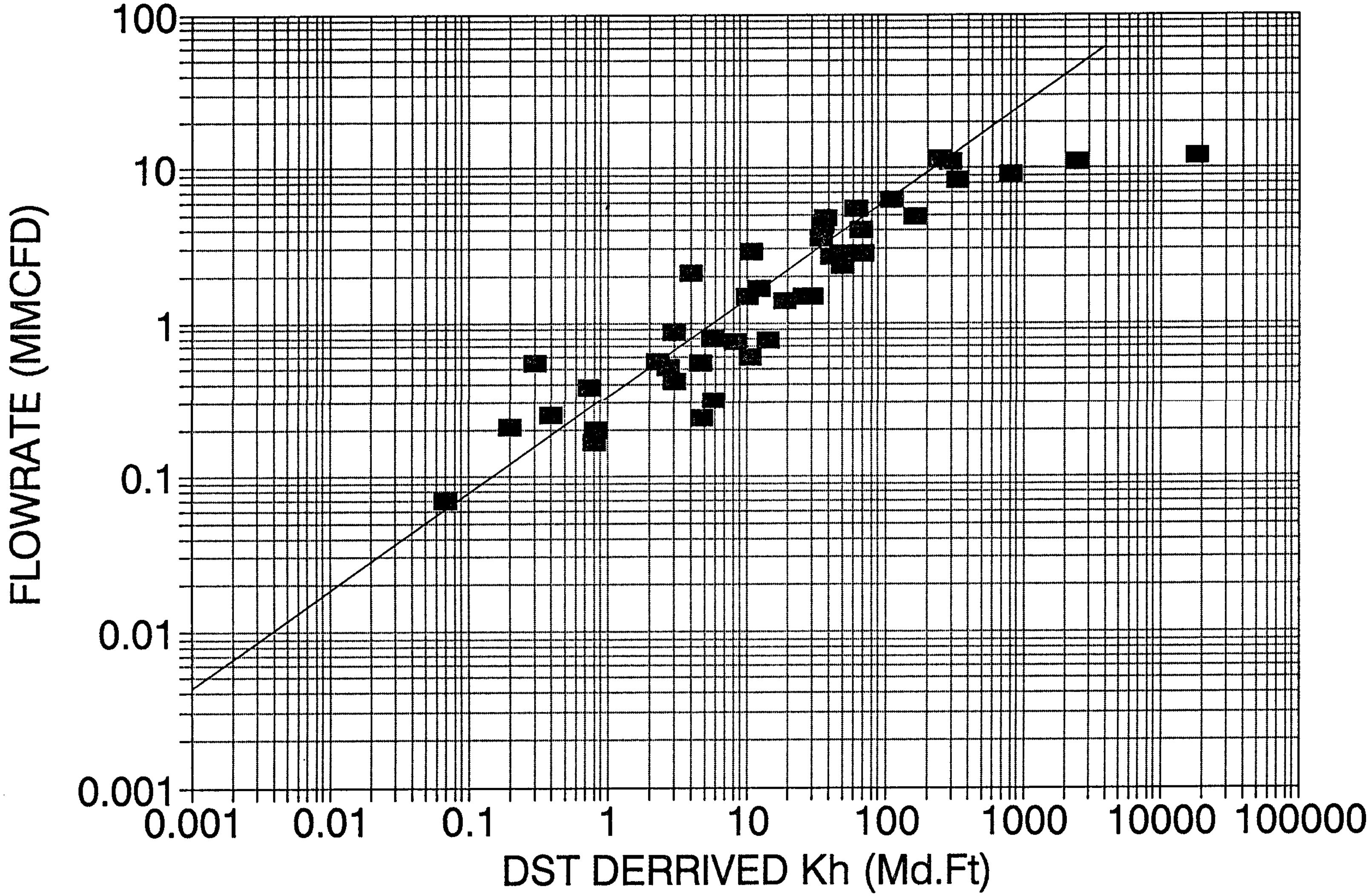

Figure......3
SADME S22591

OVERVIEW OF MONTE CARLO SIMULATION METHOD

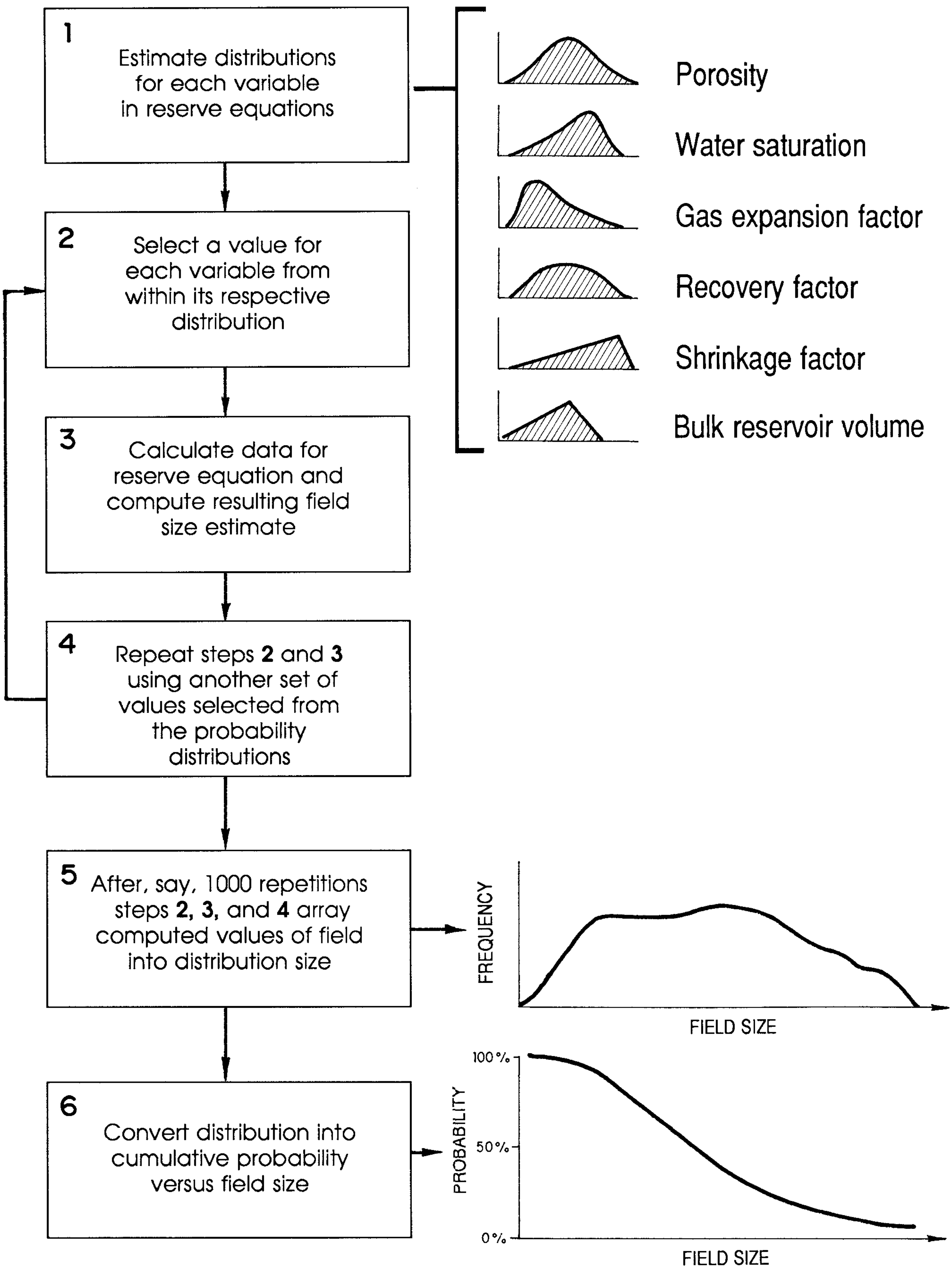

Figure..... 4
SADME S22509

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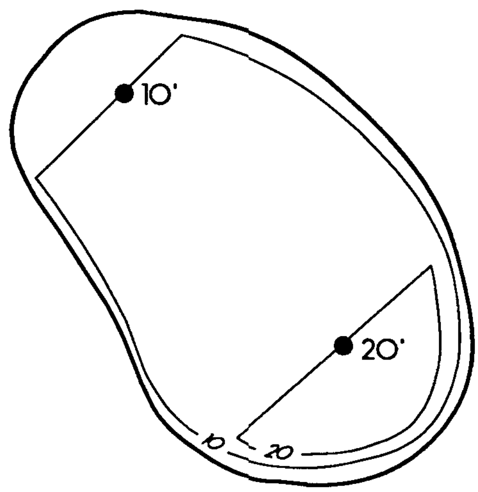
CONTOURING

2 WELL FIELDS (OIL and GAS)



3 WELL FIELDS (OIL and GAS)

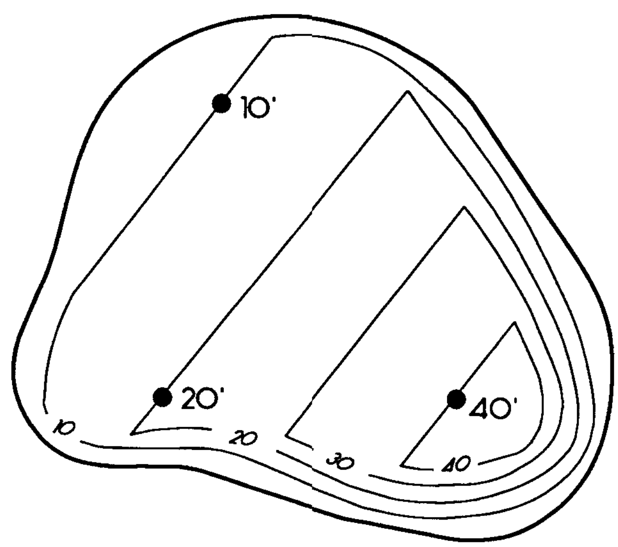


Fig. 5

SADME S 22510

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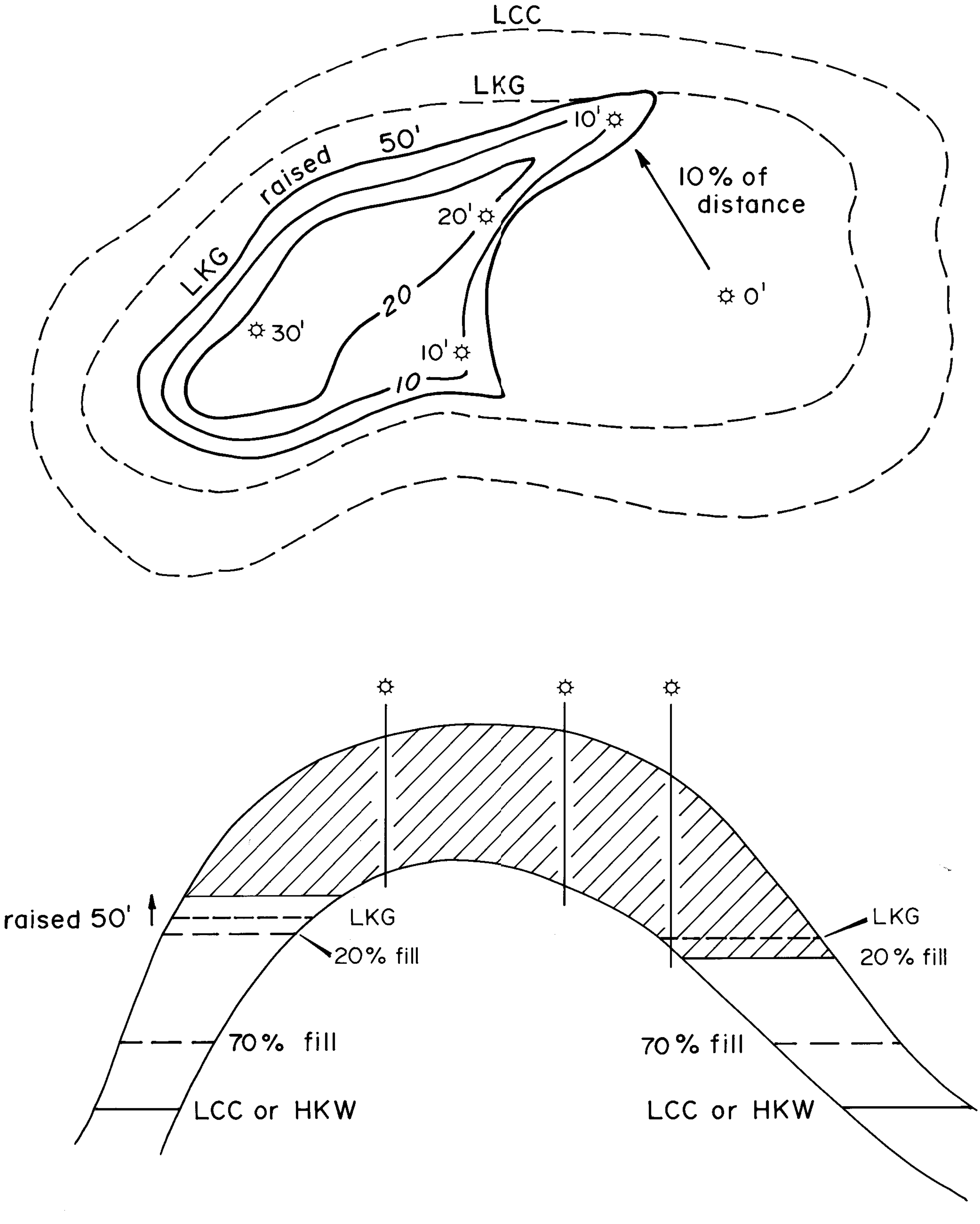

OGIP – 90% Confidence

Figure 6
SADME S 22511

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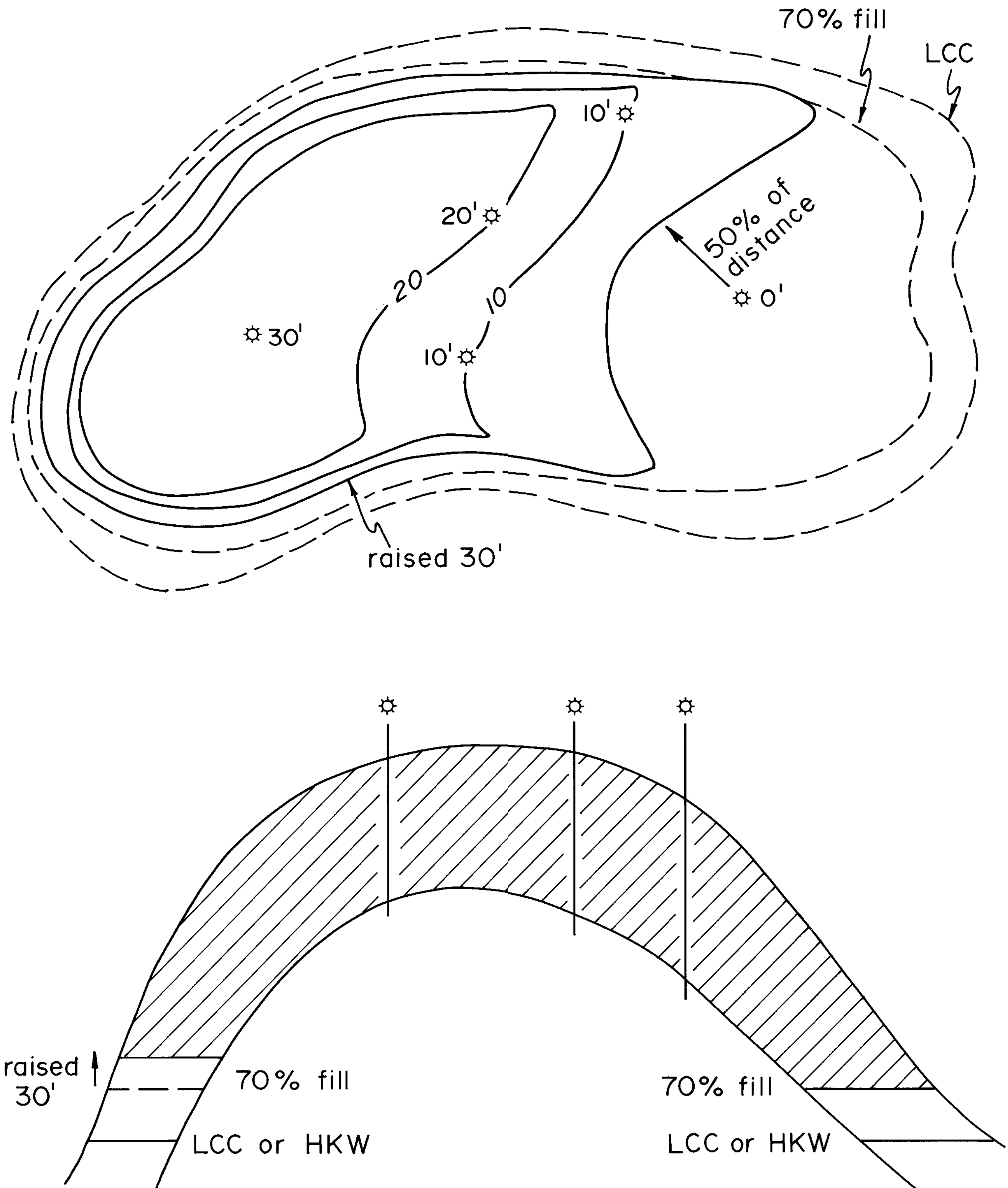

OGIP — 50% Confidence

Figure......7
SADME S22512

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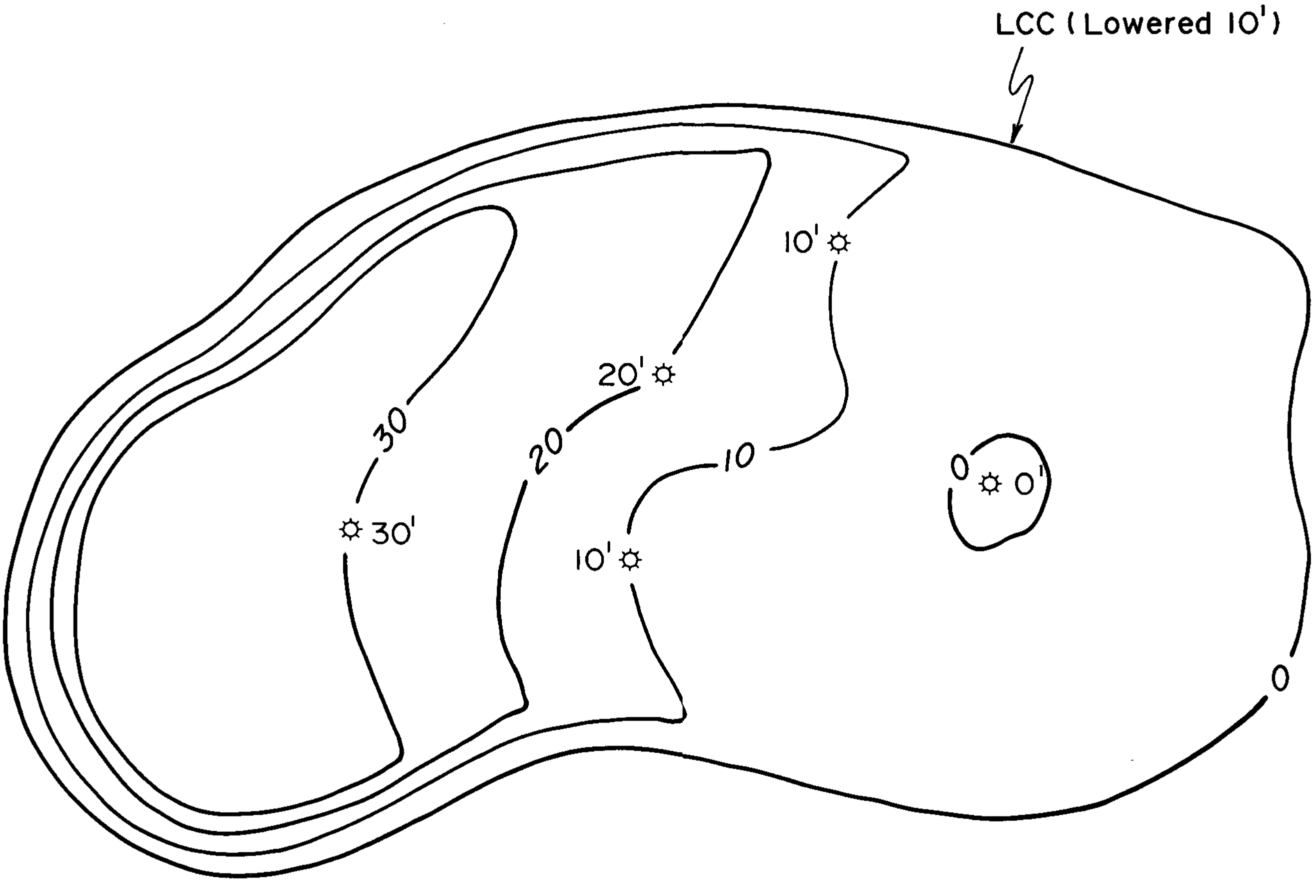

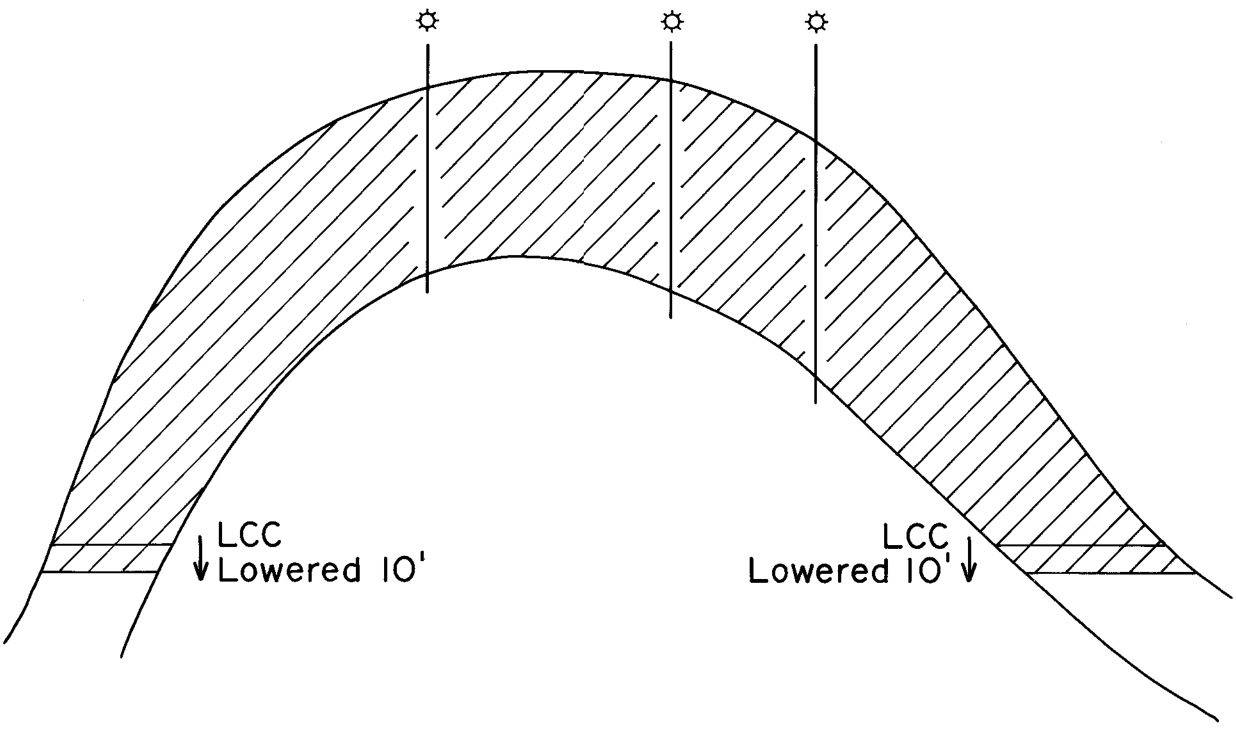

OGIP — 10 % Confidence

Figure......8
SADME S 22513

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