**Reserve Estimates in Western Basins
Part III: Unita Basin**

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Final Report

October 1995

Work Performed Under Contract No.: DE-AC21-91MC28130

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

By
The Scotia Group
Dallas, Texas

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Morgantown Energy Technology Center
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October 1995

ABSTRACT

This study characterizes an extremely large gas resource located in low permeability, sandstone reservoirs of the Mesaverde group and Wasatch formation in the Uinta Basin, Utah. Total in-place resource is estimated at 395.5 Tcf. Via application of geologic, engineering and economic criteria, the portion of this resource potentially recoverable as reserves is estimated. Those volumes estimated include probable, possible and potential categories and total 3.8 Tcf as a mean estimate of recoverable gas for all plays considered in the basin.

Two plays were included in this study and each was separately analyzed in terms of its tight gas resource, established productive characteristics and future reserves potential based on a constant \$2/Mcf wellhead gas price scenario. A scheme has been developed to break the overall resource estimate down into components that can be considered as differing technical and economic challenges that must be overcome in order to exploit such resources; in other words, to convert those resources to economically recoverable reserves.

About 82.1% of the total evaluated resource is contained within sandstones that have extremely poor reservoir properties with permeabilities considered too low for commerciality using current frac technology. Cost reductions and technology improvements will be required to unlock portions of this enormous resource.

Approximately 13.4% of the total resource is contained within sandstone reservoirs which do not respond to massive hydraulic fracture treatments, probably due to their natural lenticular nature. Such depositional systems include most sands to the west of the Green River. A detailed study of these systems and improvements or innovations in well completion and stimulation are required to exploit this resource.

Approximately 1.3% of the total resource is located in deeply buried settings below deepest established production. This resource is poorly defined due to sparse well control and the need for extrapolation of volumetric parameters from areas of better control. Additional deep drilling is required to characterize and better quantify this resource. This will require considerable price incentive, given the costs and risks involved.

Approximately 3.2% of the total resource is considered to represent tight reservoirs that may be commercially exploited using today's hydraulic fracturing technology. From the viewpoint of current economics, drilling and completion costs, and risk, about 1% of the total resource has favorable risked expectations with the other 2.2% having unfavorable risked expectations. Reserves estimates consider both categories.

Total recoverable reserves estimates of 3.7 Tcf do not include the existing production

from Wasatch and Mesaverde reservoirs in the basin. These have an estimated ultimate recovery of approximately 612 Bcf, or a per well average recovery of 592 MMcf. Due to the fact that considerable pay thicknesses can be present, wells can be economic despite limited drainage areas. It is typical for significant bypassed gas to be present at inter-well locations because drainage areas are commonly less than regulatory well spacing requirements.

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In addition Coastal Corporation, CNG, Dowell Schlumberger, Enron, and Halliburton are specifically acknowledged for sharing their time, expertise and databases on fracturing treatments and results in the Uinta Basin. This data and its interpretation was so significant that it has been the subject of a separate topical report.

The Scotia project team consisted of Rob Caldwell (project manager), Mark Cocker (geology, petrophysics), Simon Bidwell (engineering and petrophysics), Bill Cotton (computing, databases), Ian Howrie, Jim Merkel, Dave Heather, Pat Wagner, and Wayne Beninger (reservoir engineering), Wendy Edmondson and Laurie Pasch (support), Mary Ann Moss (administration), and Jonathan Boarman (GIS). Tom Carroll and Ken Ibsen provided consulting engineering and data support services. Al Jaffe acted as consulting business coordinator. These individuals are acknowledged for their diligent efforts.

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INTRODUCTION

Vast quantities of natural gas are entrapped within various tight formations in the Rocky Mountain area. This report seeks to quantify what proportion of that resource can be considered recoverable under today's technological and economic conditions and discusses factors controlling recovery. The ultimate goal of this project is to encourage development of tight gas reserves by industry through reducing the technical and economic risks of locating, drilling and completing commercial tight gas wells.

This report, the third of three, focuses on the Uinta Basin located in northeastern Utah. The first report (Scotia, 1993) analyzed the tight gas reserves and resources in the Greater Green River Basin (GGRB). The second report (Scotia, 1995) analyzed the tight gas reserves and resources in the Piceance Basin, northwestern Colorado. Since each report is a stand-alone document, duplication of language will exist where common aspects are discussed.

The U.S. Geological Survey (USGS) resource assessments have been the starting point for this series of studies. In the case of the Uinta Basin, the USGS chose to not perform an initial volumetric estimate of in-place resources. Rather, a non-volumetric geostochastic approach was used (Fouch et al, 1994) in an as-yet unpublished report prepared for the U.S. Department of Energy (DOE) to assess potential reserves additions in nonassociated gas accumulations in the Mesaverde group and Wasatch formation. Computations were performed using the program, UNCLE (unconventional energy). This program uses analytical probabilistic methods to estimate reserves and requires as input defined geologic plays and their associated risk, historical EUR distributions, and drilling and completion success ratios. The play breakdown and results are summarized as follows:

USGS PLAY	MEAN ESTIMATED POTENTIAL RESERVES BY PLAY Tcf, RECOVERABLE
Wasatch Gas-Saturated (east of Green River)	2.14
Wasatch Gas-Saturated (west of Green River)	0.51
Wasatch Gas with Water Contacts – subsequently dropped by USGS	1.62
Mesaverde Gas-Saturated < 15,000 feet (basin flank)	3.78
Mesaverde Gas-Water Transitional – subsequently dropped by USGS	1.48
Mesaverde Gas-Saturated > 15,000 feet (deep basin centered)	0.57
TOTAL	10.10

USGS play boundary definition is based substantially on thermal maturity and to allow comparison of results, we have incorporated these play boundaries into our study. The two formations containing tight gas resources are the Mesaverde group and Wasatch formation. These are subdivided into two Wasatch and three Mesaverde subplays as discussed in detail later. In the subsequent National Assessment (1995), the two transitional plays were reclassified out of the unconventional category, resulting in a total estimated reserves potential of 7 Tcf.

In order to perform this study in a comparable fashion to previous works on the GGRB and Piceance Basin, it was necessary to perform a volumetrically based in-place resource estimate as a starting point. Resources were calculated deterministically by Scotia based on the following procedure:

1. A suite of structure and thickness maps was created for each play which included:
 - a. structure map for the top and base of each play
 - b. gross thickness map
 - c. sandstone map
 - d. pay thickness map.
2. Sandstone and pay thickness maps were gridded and each grid cell assigned its midpoint play depth. Rock volume data was then sorted into 500 foot depth slices.
3. Porosity and water saturation distributions were generated for each depth slice for all sandstones and for pay sandstones only from detailed well log analysis.
4. Similarly, the appropriate gas formation volume factor (FVF) was determine for each depth slice.
5. The estimated resource in-place was calculated by play for all sandstones and for pay sandstones only.

Table 1 summarizes the estimated total resources in-place for all sandstone.

TABLE 1
ESTIMATED RESOURCE BY SUBPLAY

SUBPLAY	Tcf IN-PLACE
Mesaverde Gas-Saturated Deep Synclinal > 15,000'	47.8
Mesaverde Gas-Saturated $R_o > 1.1$ & < 15,000'	200.7
Mesaverde Gas-Water Transitional R_o 0.70-1.1	87.1
Wasatch Gas-Saturated	39.7
Wasatch Gas-Water Transitional	20.2
TOTAL	395.5

This represents a large estimated gas resource. Historically, the Uinta Basin tight gas plays have not been prolific producers due to a variety of factors, including regionally depressed gas prices, generally poor infrastructure, poor well productivity, and resulting marginal economics. In recent years several of these factors have changed resulting in a more positive outlook for the basin and the conversion of parts of this giant resource to reserves. Addressing these changes and documenting their effect on the "resource to reserves" process is the subject of this report.

To address what portion of the resource may be called "reserves," it should be clearly stated that the project brief is directed at the category classified as unproved reserves (i.e., probable and possible) under standard Society of Petroleum Engineers (SPE) definitions. In the strictest sense, such an analysis should be restricted only to volumes that have been discovered, with normal techniques for estimation being consideration of differing recovery factors or drainage radii around wells and allocating certain proportions to the probable and possible categories. Considering the immaturity of the plays, such an approach would simply be a geometry exercise with little relevance to the larger aspect of reserves potential and future contribution to the national gas supply picture. As a result, "reserves," as used in this study, comprise volumes normally classified as probable and possible and also includes "potential reserves," that may qualify as commercial but remain undiscovered in the strictest sense. This definition and discussion of the distinction between "discovered" and "undiscovered" when dealing with unconventional resources is elaborated upon in the text.

This project seeks to not only document the performance and reserves from Mesaverde and Wasatch gas wells in the Uinta Basin, but also to explore the reasons behind differing recovery factors. Quantification of the reasons behind differing well performance is complex due to changes in reservoir properties and varying degrees of success of the massive hydraulic fracture treatment that is necessary to effect a commercial completion.

This report seeks to keep in focus the ultimate objective of encouraging further exploitation of the resource by industry. The process of successfully locating, drilling, completing, fracture treating, and producing a Mesaverde and/or Wasatch gas well involves an interplay of complex geological, petrophysical and reservoir engineering components. Since the study and evaluation of tight gas reservoirs involves considerably more complexity than a conventional gas play, and because the technology is evolving rapidly, a diverse, varied and sometimes confusing technical literature base exists. For those who are not involved in the field on a day-to-day basis, a working understanding of the components of the tight gas problem may be found in the appendices of our previous report (Scotia, 1993) on the GGRB. These appendices include technical and summary background information on aspects of hydraulic fracturing, log analysis and the use of core data and its correction to provide in-situ values.

It should be noted that in working with tight gas reservoirs, a greater degree of complexity and hence uncertainty is involved in comparison with conventional gas reservoirs. This uncertainty arises not only from the degree of heterogeneity normally exhibited by tight gas reservoirs, but also due to the fact that conventional technical tools for measuring aspects such as reservoir properties (conventional logs, core analysis, DST data, etc.) were designed for use in conventional reservoirs. The data sources require special treatment and modification of approach, through to total data rejection in terms of supplying information which is useful in an analysis. Due to the low permeabilities and generally low porosities involved, most conventional measuring devices are at the lower end of their accuracy limit, introducing an additional base element of measurement error. All of these factors complicate the acquisition of base data, the reliability of such data, and its ultimate overall relevance to an evaluation. As a result, it is common for evaluation work to include an element of uncertainty, either via conducting analyses deterministically but providing ranges for input variables, or in fact taking such analyses to the next stage and working probabilistically. The original USGS reserves estimate was performed probabilistically: that is, the final results were presented as a numeric value with an associated probability level.

The USGS approach has been adopted somewhat in this study via expressing reserves results in the form of an estimated distribution. This system provides a quantitative and consistent methodology for expressing potential reserves data in evaluation situations typified by wide variation in individual well performance or, as otherwise expressed, in statistical type plays. The evaluation of reserves for Mesaverde and Wasatch tight gas sands represents such a situation. It should be noted that in many cases it is not possible to accurately measure each of the factors controlling ultimate recovery or to determine which factors have the most impact.

SUMMARY OF RESULTS

1. Evaluation of the base *in-place* tight gas resource by this study yields an estimate of 395.5 Tcf.
2. Of this base resource, 324.8 Tcf is contained within sandstones that are of extremely poor reservoir quality, having estimated in-situ permeabilities of less than 0.001 md and also sandstones having low gas saturation due to limited charge. Such resources are termed *technologically nonviable* since they are contained in reservoirs that are considered too tight for commercial exploitation using today's hydraulic fracturing technology. Portions of this resource will only become accessible via future cost reduction and improvement in massive hydraulic fracturing technology.
3. The remaining 70.7 Tcf represents resources that are contained in reservoirs considered to have in-situ permeabilities greater than 0.001 md and are termed *technologically viable*. Of this resource, 53.1 Tcf (13.4% of the total) is termed *nondemonstrated* since it is contained in reservoirs that have not been shown to be commercially productive. New developments in well completion and stimulation will be required to access these resources.
4. The remaining 17.6 Tcf represents *demonstrated* resources. These are in-place volumes that are potentially available for conversion into reserves by application of an appropriate recovery factor. Of this volume, 3.8 Tcf (1% of the total) is considered to be *established* resource characterized by favorable expectations in terms of recovery and drilling risk. A further 8.6 Tcf (2.2% of the total) is considered *nonestablished* resource characterized by less favorable expectations in terms of recovery and a higher drilling risk and cost. The differentiation of the *established* and *nonestablished* resource categories is based upon a drill depth criterion termed *economic basement*. *Economic basement* is a conceptual depth that depends upon drilling and completion costs, expected reserves, gas price, and success ratios. Changes in these parameters will cause dynamic movement of resources from one category to the other. The remaining 5.2 Tcf of *demonstrated* resources are considered *speculative*. *Speculative* resources are those occurring in deeply buried locations, characterized by poor well control and being deeper than any *established* commercial production. Such volumes are inferred by extrapolation of mapping into the deep basinal areas and are defined as being below the *deepest commercial production*. *Speculative* resources have a high degree of uncertainty associated with their quantification and are thus excluded from consideration from a reserves quantification perspective.
5. Table 2 summarizes the resource high-grading procedure:

TABLE 2
BREAKDOWN OF RESOURCE ESTIMATE (Mean Values)
(Tcf)

Scotia Mean Resource Estimate	395.5
MINUS <i>Technologically Nonviable Resources</i>	324.8
SUBTOTAL <i>Technologically Viable Resources</i>	70.7
MINUS <i>Nondemonstrated Resources</i>	53.1
SUBTOTAL <i>Demonstrated Resources</i>	17.6
Subdivision: <i>Speculative Resources</i>	5.2
<i>Nonestablished Resources</i>	8.6
<i>Established Resources</i>	3.8

Only established and categories are considered for the purpose of estimating recoverable reserves.

6. Recoverable reserves, inclusive of probable, possible and potential categories, are estimated at 0.9Tcf and 2.3 Tcf respectively for the established and *nonestablished* categories for a total of 3.2 Tcf. These represent MAXIMUM recoverable volumes assuming a variable drilling pattern that leaves NO bypassed gas. The estimated ultimate recoveries (EUR) for existing Mesaverde and Wasatch gas wells are not included in these figures.
7. Mesaverde and Wasatch gas wells are characterized by significant variation in average drainage radius. Due to large pay thicknesses, they may drain comparatively small areas. The principal development area in the basin is the Natural Buttes Field. Continuing development of this large field via infill drilling has reduced gas well spacing to 40 acres per well in most areas.
8. The Wasatch Play contains all of the *established* resources and is the principal producing play in the basin with a combined EUR of 428 Bcf for existing wells. *Nonestablished* resources are contained in portions of the Wasatch and Mesaverde plays. These plays represent a combined EUR of 185 Bcf for existing wells. Large portions of both the Wasatch and Mesaverde plays have no commercial production or are undrilled. These areas contain *nondemonstrated* resources. These resources would be available to be moved into the *established* or *nonestablished* category given future commercial development of these areas.
9. For all existing tight gas wells in the Mesaverde and Wasatch plays, cumulative production to 1 November 1994 is 451 Bcf with an EUR of 613 Bcf. This represents

proved developed producing (PDP) reserves developed mainly since 1976 in 1,035 producing wells. These EURs are lognormally distributed with average EURs for a Mesaverde gas well being 353 MMcf with a median of 200 MMcf. Average EUR for a Wasatch gas well is 627 MMcf with a median of 450 MMcf.

10. Of the 1,035 identified completions in the Uinta Basin, 916 or 89% are within the Greater Natural Buttes area, making this by far the largest field in the basin. In contrast, the next largest field in the basin contains 14 wells.
11. The Wasatch is the most prolific play in the basin in terms of EUR per well and number of wells drilled. It should be noted that early in the life of the Natural Buttes Field where the Wasatch and Mesaverde plays were commingled, production exceeded 1 Bcf per wellbore. This is an increase of 32% over an average Wasatch completion during that time. While infill drilling has reduced Wasatch spacing to 40 acres/well in most parts of the field, the Mesaverde remains undeveloped over large areas.
12. Development of the Mesaverde Play has been sparse to date. However, similarity of some lithofacies with neighboring productive basins (GGRB and Piceance), large areas of thermally mature rocks and predicted overpressuring in the deeper parts of the basin indicate that exploration potential may exist in the *nondemonstrated* portions of the Mesaverde Play if gas accumulations can be found in association with well developed interconnected natural fractures.

BACKGROUND/DISCUSSION

The USGS reserves work, including to the 1995 National Assessment of the United States Oil and Gas Reserves, has estimated mean potential tight gas reserves in the Mesaverde Play and Wasatch formation of 7 to 10 Tcf. Recognition of the reserves base represents an important step in its exploitation. Gas developments in the Uinta Basin have suffered from a combination of several "negatives." These include historically poor gas markets in terms of price and take, sparse infrastructure, the requirement for the use of expensive and still developing technology particularly in the area of frac treatments, and a generally costly environment due to local logistics, to name a few.

While the improving gas markets in the Rocky Mountain basins area are a positive factor, general industry skepticism of the resource itself and of the base economics compared to other opportunities in conventional oil and gas development are probably the main source of negative reaction towards the development of these resources.

Objectives and Purpose For Study

Encouraging commercial development of the Mesaverde and Wasatch tight gas resource is the prime objective of this study. In comparison to conventional reservoirs, tight gas reservoirs pose their own unique series of challenges. Since such challenges often involve the development and application of new technologies, and because such technologies can involve a significant cost component over those normally used in conventional reservoirs, a double negative is created by virtue of increased cost and increased risk (representing the very real possibility that such expenditures will be unsuccessful in providing an economic return). As noted by Holditch (1992), despite the development and proof of concept of many of the technologies applied to tight gas development, such technologies have not been widely accepted for various reasons. Included amongst these is the inertia involved in technology transfer and demonstration that such technologies are indeed cost-effective.

It should be noted that the exploitation of tight gas reserves involves physical measurements that can be at the lower limit of resolution of the various tools utilized in their measurement. Since such tools were designed and calibrated for conventional reservoirs, aspects of resolution and measurement error become of prime concern in tight gas. As such, taking certain measurements at face value without application of corrections or judgmental adjustments can often lead to faulty interpretations. These pitfall areas are identified and discussed in our previous report on the GGRB (Scotia, 1993), including appendices describing the state of current technologies.

Finally, this report has been designed to provide not only our interpretations but to also share the base data so that others may complete their own analyses. This data is included in

summarized form (both tabular and graphical) within the body of this report and is provided in digital form on request as a separate database.

Uinta Basin Geological Setting

The Uinta Basin, located in northeastern Utah, covers approximately 10,300 square miles (Figure 1). The basin is bounded by the Uinta Mountains and Wasatch range to the north and northwest, the Douglas Creek Arch and Uncompahgre Uplift to the east and southeast, and the Wasatch plateau and San Rafael Uplift to the southwest (Figure 2). The basin was formed by Laramide style tectonism between Late Cretaceous and Paleocene-Eocene time (Franczyk et al, 1992). It formed as a result of crystalline basement uplifting within an existing marine foreland basin (Cretaceous Epeiric Sea) which broke up the area into a series of inter-montane basins, some of which included the Green River and Piceance basins (the subjects of Phases I and II of this study). The Uinta Basin is separated from the Piceance Basin to the east by the Douglas Creek Arch, which served as a barrier to sedimentation intermittently during Late Cretaceous/Early Tertiary.

Late Cretaceous basin subsidence marked the beginning of a major episode of marine sedimentation beginning with the Mancos shale which underlies the Campanian Mesaverde in the Uinta Basin. The Mesaverde group is about 2,500 to 3,000 feet thick in the Uinta Basin and can be divided into two major units: a lower unit made up of several regressive marine cycles in the eastern part of the basin and extending into the Piceance Basin, which inter-tongue with the underlying and laterally equivalent marine Mancos shale, and an upper mostly alluvial and coastal plain unit. Most gas encountered in the Upper Cretaceous sandstones occurs in rocks deposited in braid plain and coastal plain settings (Fouch et al, 1992).

The paleogeography across Uinta during Late-Early Campanian times consisted of predominantly braid plain deposits west of the Green River grading to coastal plain and seaway (Mancos) with a northeast striking paleo coastline in the eastern half of the basin. The sea gradually regressed to the southeast resulting in the deposition of the alluvial Six Mile Canyon formation, coastal Star Point and Black Hawk formations, and the Castlegate sandstone, but transgressed again during early-late Campanian allowing the Buck Tongue of the Mancos shale to extend across the Green River, at least over the southern half of the basin. The shoreline regressed again depositing the Sego sandstone and by Late Campanian the Uinta Basin was covered entirely by braid plain deposits of the Price River, Tuscher and Farrer formations. This increased non-marine deposition represented a reduced rate of basinal subsidence and withdrawal of the Cretaceous seaway from this area.

Figure: 1

LEGEND

- TERTIARY ROCK LIMIT
- CAMBRIAN - LOWER CRETACEOUS OUTCROP
- PRECAMBRIAN ROCKS

Modified from Johnson (1989)

U.S. Department of Energy

NE UTAH, NW COLORADO, & SW WYOMING
BASINS AND UPLIFTS
CREATED IN LARAMIDE OROGENY

Prepared by The Scotia Group, Inc.

Figure: 2

An unconformity at the top of the Mesaverde marks the onset of the Laramide orogeny 72 to 40 million years ago (mya) which created uplifts subdividing the Cretaceous foreland sedimentary basin, and providing local sediment sources. Though areas between the local uplifts continued to subside and receive sediments, the Uinta Basin edges became uplifted and eroded, resulting in the removal of thousands of feet of section.

Maastrichtian to Eocene strata consist of open lacustrine and marginal lacustrine depositional facies deposited in and around Lake Flagstaff (Paleocene) and Lake Uinta (Eocene), and alluvial/fluvial facies deposited around the lake edges in a complex inter-tonguing relationship with the lake sediments.

The North Horn, Colton and Wasatch formations are mostly fluvial/alluvial and lie unconformably on top of the Mesaverde sediments. The Maastrichtian to Late Paleocene North Horn formation underlies and inter-tongues with the Flagstaff member of the Green River formation in western Uinta and the Wasatch plateau (Fouch et al, 1983). The formation forms a sedimentary wedge as it pinches out against the Cretaceous highs of the Uncompahgre Uplift. The Colton formation, Paleocene to mid-Eocene, overlies the Flagstaff member of the Green River formation and underlies the Green River formation itself in western Uinta. The Wasatch Paleocene-Eocene overlies the Mesaverde group, or the Flagstaff member of the Green River formation and also inter-fingers with the Green River formation. In western Uinta the Wasatch consists of up to 5,000 feet of Paleocene-Eocene rocks. While in eastern Uinta, the formation ranges in thickness from less than 500 feet at the basin margin to 3,000 feet.

The Upper Paleocene to Eocene Green River formation includes lacustrine marlstone and oil shale, and marginal lacustrine sandstone, siltstone, ostracodal, oolitic and stromatolitic limestone, carbonate rich mudstone and carbonaceous shale with thin coalbeds (Johnson and Nuccio, 1993). During the Paleocene, Lake Uinta was restricted to the western Uinta Basin and along the Wasatch plateau (Fouch, 1976). It later expanded during the Eocene to cover much of the Uinta and Piceance basin.

The Late Eocene Uinta formation is made up of lacustrine, marginal lacustrine and fluvial sandstone, siltstone and mudstone which inter-tongue with the underlying Green River formation. The overlying and inter-tonguing Duchesne formation is an Upper Eocene fluvial deposit of lenticular sandstones and mudstones limited to the central part of the Uinta Basin. A chronostratigraphic diagram across the south rim of the Uinta Basin, Figure 3, displays the relationships between early Cretaceous through Eocene strata.

FIGURE 3

Albian to Middle Eocene Chronostratigraphic Diagram Across South Rim of Uinta Basin
(from Fouch et al, 1993 and Franczyk et al, 1989)

The bulk of hydrocarbon production occurs from Tertiary reservoirs with a smaller contribution from the Upper Cretaceous Mesaverde group. The open and marginal lacustrine rocks of the Green River formation produce mostly oil and associated gas with the majority of production from the Altamont Bluebell and Redwash fields, situated in the north and northeast parts of the basin respectively. The alluvial facies of the North Horn, Wasatch, and Colton formations produce mainly nonassociated gas with the majority of production coming from the Natural Buttes Field situated in east central Uinta, east of the Green River.

The Uinta Basin gas reserves identified by the USGS are contained in the lower permeability sandstone reservoirs of the Mesaverde group located in the central and eastern portions of the basin and the Wasatch formation (including undifferentiated North Horn, Flagstaff and Green River inter-tonguing), located predominantly east of the Green River and partly in the south part of the basin. These reservoirs usually have an in-situ permeability to gas of less than 0.1 millidarcies and require hydraulic fracturing to produce gas at commercial

rates. A large portion of the gas accumulation is interpreted to be a basin-centered type similar to that described by Masters (1979). In terms of gas distribution, the basin may be subdivided into three zones: a shallow water-bearing zone which occurs at the basin margins, a deeper transitional zone which contains sands that are both gas-saturated and water-saturated, many with gas-water contacts, and a deeper basin-center gas-saturated zone. The top of the gas zone cuts across stratigraphic boundaries and grades vertically and updip through the transition zone into water-bearing reservoirs. Trapping of the gas in the continuous gas-saturated rocks requires the creation of a relative permeability barrier in very low permeability rock within the transition zone. This barrier, or seal, is not perfect and likely allows leakage of gas over geologic time. Consequently, a continuous gas supply (present day generation) is required to maintain the accumulation. Trapping of the gas in the gas-water transitional zone however is related to stratigraphy, particularly in the immature Wasatch formation.

Two groups of thermogenic gas have been identified in the Uinta Basin. The first ("Class A," Fouch, 1992) is nonassociated, chemically and isotopically heavy, generated from Type III non-marine kerogens (oxygen rich, hydrogen poor) in the Mesaverde group and is produced from the Mesaverde, Wasatch and inter-tonguing Green River formation. The second group ("Class B," Fouch, 1992) is associated with oil, is chemically wet and isotopically light, and is generated from Type I lacustrine kerogens (hydrogen rich) of the Green River formation in the northern part of the basin.

The onset of gas generation in Type III (humic) gas prone source rocks is recognized by Fouch et al (1992) to begin at a vitrinite reflectance, R_o value (measurement of thermal maturity) of 0.75%. It should be noted however that the updip boundaries used by the USGS for the Wasatch and Mesaverde gas-water transitional plays coincides with an R_o of 0.7% at the base of the Mesaverde group. Johnson (1987, 1989) used an R_o value of 0.73% to define gas-water transitional play boundaries in his resource study of the Piceance Basin and favored this value during surface vitrinite reflectance studies of the Uinta and Piceance basins (Johnson and Nuccio, 1993). The bulk of Mesaverde gas production exists within rocks with R_o s higher than 0.75%. Though migration distances are speculated to be small in low permeability basins and gas accumulations, some tight gas fields (for example Oil Springs in eastern Uinta), do lie outside the 0.75% R_o boundary. The bulk of Wasatch production occurs from rocks which are immature ($R_o < 0.75\%$). These rocks are sourced by the underlying Mesaverde group and require a well developed fault and fracture network to facilitate the gas migration process. Reservoirs in a basin centered gas accumulation are not normally associated with discrete GWCs and gas saturation is usually continuous and independent of structure. However, at Natural Buttes GWCs do exist in the productive sands of the Wasatch formation. Gas in the Wasatch formation is restricted to those areas where migration from the Mesaverde can occur, whereas gas in the Mesaverde formation is predicted to be widespread.

Figure: 4

FIGURE 5

Generalized Structural Cross-Section A-A' Displaying Stratigraphy and Play Outlines Approximate Line of Section Shown on Figure 4

FIGURE 6

Generalized Structural Cross-Section B-B' Displaying Stratigraphy and Play Outlines Approximate Line of Section Shown on Figure 4

Basin topography is depicted on Figures 4, 5 and 6. Overall, the structural relief is far less than that of the Piceance Basin. The majority of the northeastern area of the basin is relatively flat. To the south and west however, elevation changes by as much as 3,500 feet. Figures 5 and 6 are cross-sections which display the generalized structure and stratigraphy in northwest-southeast and southwest-northeast directions across the basin. The Mesaverde and Wasatch play outlines are also shown. Note that since the Wasatch is sourced via vertical fractures by the Mesaverde, the Wasatch Play boundaries coincide with those of the Mesaverde to a large extent.

Drilling and Production History

The following discussion is limited to the drilling and production history trends within the Mesaverde group and Wasatch formation of the Uinta Basin, since these contain the nonassociated tight gas resources. Other formations in the basin produce oil and associated gas.

Exploration in the Uinta Basin dates back to the 1920s, however it was not until the early 1960s that gas production was established from the Mesaverde and Wasatch. Limited in part by lack of infrastructure, serious development of the tight gas reservoirs did not occur until the late 1970s with rapid development in the 1980s and again in the early 1990s, immediately prior to the expiration of the Section 29 tax credits. Table 3 summarizes the drilling and completion history based upon data derived from PI's WHCS database. This data set has been culled to exclude wells outside the basin outline depicted in Figure 2.

TABLE 3
DRILLING AND COMPLETION HISTORY IN FIVE YEAR INCREMENTS

PERIOD	NUMBER OF DRY HOLES			MESAVERDE COMPLETIONS	WASATCH COMPLETIONS	DRY HOLE PERCENTAGE
	TD Above Mesaverde	TD in Mesaverde or Below	Total Dry Holes			
1945-1949	5	2	7	0	0	100
1950-1954	24	12	36	0	0	100
1955-1959	13	6	19	0	0	100
1960-1964	25	11	36	1	12	73
1965-1969	34	5	39	0	0	100
1970-1974	13	5	18	0	0	100
1975-1979	7	4	11	22	126	7
1980-1984	13	5	18	39	228	6
1985-1989	3	0	3	36	173	1
1990-1994	0	0	0	39	363	0

Figure: 7

LEGEND

- NATURAL BUTTES COMPLETION
- GREEN RIVER
- CONTOURS

U.S. Department of Energy

Uinta Basin
NATURAL BUTTES AREA
SHOWING TOP OF WASATCH FORMATION

Prepared by The Scotia Group, Inc.

FIGURE 8

The dry hole counts in Table 3 represent all occurrences. In many cases, objectives were either deeper, for example, the Dakota formation, or were oil plays in the Green River and Uinta formations. As such, the dry hole percentages calculated by including only Mesaverde and Wasatch completions, represent a worst case situation in that completions in other units are not considered. Nevertheless, it is evident that following the initial early exploration of the basin, a very low percentage of dry holes were drilled in the basin in comparison to the number of gas completions. Recent Mesaverde and Wasatch dry holes represent mostly mechanical failures.

The Natural Buttes Field is the main producing area for the Mesaverde and Wasatch within the Uinta Basin. The current EUR for the field is 585 Bcf accounting for 95% of the currently estimated total tight gas producing capacity of the basin. Though the field produces from both the Mesaverde and Wasatch, the Wasatch is the primary producer comprising 87% of the completions. As of the date of this study, 1,039 well completions exist in the overall Natural Buttes Field area. The field has an irregular shape (Figure 7) covering an area approximately 30 miles by 15 miles. Ongoing drilling activity in the field consists of extension and infill drilling with well spacing down to 40 acres in many parts of the field. The extension and infill drilling programs were accelerated during the early 1990s, probably motivated by the expiration of the Section 29 tax credits resulting in considerable reserves growth.

In reviewing the development of the play, it is useful to examine the sequence of reserves additions at the well level as shown in Figure 8. This series of displays looks at per well EURs as a function of completion number (first well drilled through to the most recent) and as a function of time. In many plays it is common to observe that the best wells are drilled early in the life of the play. With time, the EUR per well decreases as a function of smaller target size and partial drainage of infill locations. As shown in Figure 8, while it is evident in the averaged completion sequence plot that per well EURs have steadily declined, when averaging is performed in a time increment, the declining trend is much less evident. This is due to the significant amount of drilling that has occurred within the early 1990s (see completion time increment plot for numbers of wells in each time increment). Since almost half of the total wells drilled in the tight gas study area have been drilled within the last five years, about half the points on the completion sequence plot are represented by the last sample on the time increment plot. This does, however, indicate that though infill drilling has occurred down to a 40 acre spacing, only in the most recent wells are drainage effects evident.

As a result of drilling activity in the early 1990s, gas production from the Mesaverde and Wasatch plays (Figure 9) has increased markedly as shown in this vintaged production plot. Note that the period in the late 1980s represents regional curtailment as opposed to a decline in deliverability. The dramatic increase in gas production can be directly related to the drilling that occurred in the early 1990s which now contributes about two thirds of the gas supply from this play.

FIGURE 9

Table 4 illustrates the historical and current play demographics. The historical table is sorted by total reported completions and the current demographics sorted in order of currently active completions. In both cases, the play is dominated by three principal operators: Coastal, Enron and CNG. All three operate within the Natural Buttes Field. Despite having their operations concentrated in different portions of the field, the average EUR per completion is remarkably similar for all three principal operators despite significantly different completion practices. This is elaborated upon later in this report. In reviewing the results of other operators, Conoco and Wexpro stand out as having superior average per completion EURs of over 1 Bcf. Examination of the well densities indicates these operators have not been actively infill drilling. Currently activity is limited and wells display a considerably larger spacing than the other operators.

TABLE 4
HISTORIC AND CURRENT PLAY DEMOGRAPHICS

HISTORICAL PLAY DEMOGRAPHICS								CURRENT PLAY DEMOGRAPHICS							
Operator	Original Completions	Recomps	Total Compltns	Oil EUR (Mbo)	Gas EUR (MMcf)	Equiv EUR (MMcfe)	Equiv EUR /Compln	Operator	Total Completions	Active Compltns	Equiv EUR (MMcfe)	Cum Prod (MMcfe)	Reserves (MMcfe)	Current MMcfe/d	Mcfe/d /compln
COASTAL OIL	494	3	497	416	303,281	305,777	615	COASTAL OIL	497	385	305,777	225,706	80,071	214.94	558
ENRON OIL & GAS	159	3	162	128	104,725	105,493	651	CNG PRODUCING	158	146	99,272	69,100	30,172	78.08	535
CNG PRODUCING	154	4	158	256	97,736	99,272	628	ENRON OIL & GAS	162	112	105,493	75,061	30,432	62.01	554
SNYDER OIL	34	2	36	59	11,656	12,010	333	CONOCO INCORP	31	28	31,400	23,152	8,248	9.63	344
CONOCO INCORP	31	0	31	63	31,022	31,400	1,012	SNYDER OIL	36	25	12,010	9,976	2,034	4.34	174
ANADARKO PET	24	4	28	0	1,438	1,438	51	ANADARKO PET	28	24	1,438	618	820	2.84	118
WEXPRO COMPANY	22	1	23	131	22,630	23,416	1,018	WEXPRO COMPANY	23	19	23,416	19,515	3,901	3.94	207
APACHE CORP	9	1	10	23	8,834	8,972	897	APACHE CORP	10	7	8,972	6,777	2,195	4.20	599
MCCULLISS RES	9	0	9	0	4,652	4,652	516	MCCULLISS RES	9	7	4,652	4,231	421	1.01	144
LONE MOUNTAIN	9	0	9	19	4,736	4,850	538	LONE MOUNTAIN	9	5	4,850	3,808	1,042	1.43	286
CHEVRON U S	6	2	8	32	5,422	5,614	701	CHEVRON U S	8	4	5,614	5,029	585	1.02	254
UNITED UTILITY	6	2	8	4	5,172	5,196	649	W C INVESTMENT	4	4	878	585	293	0.63	159
VALLEY OPER	6	0	6	20	1,116	1,236	206	BRIDGE OIL	4	3	1,121	719	402	0.53	176
DIAMOND SHAMROCK	5	0	5	0	408	408	81	QUINTANA PET	3	3	1,275	717	558	0.70	232
UNION PACIFIC	4	0	4	1	13	19	4	VALLEY OPER	6	2	1,236	1,227	9	0.26	129
W C INVESTMENT	4	0	4	3	860	878	219	UNITED UTILITY	8	1	5,196	4,857	339	0.65	649
BRIDGE OIL	3	1	4	2	1,109	1,121	280	BONNEVILLE FUEL	3	1	1,348	1,328	20	0.12	120
STONE D J	3	0	3	0	137	137	45	BURR OIL & GAS	1	1	1,348	881	467	0.74	737
TENNECO OIL	3	0	3	0	185	185	61	BERRY VENTURES	1	1	38	38	0	0.03	30
ANR PRODUCTION	3	0	3	1	183	189	63	NEPHI CITY	1	1	53	53	0	0.07	66
BONNEVILLE FUEL	3	0	3	0	1,348	1,348	449	PG&E RESOURCES	1	1	0	0	0	0.00	1
QUINTANA PET	3	0	3	4	1,251	1,275	425	L B INDUSTRIES	1	1	741	17	724	0.14	136
MOUNTAIN FUEL	1	1	2	0	151	151	75								
MCKENZIE PROD	1	1	2	0	845	845	422								
TXO PRODUCTION	2	0	2	0	391	391	195								

Current production as of 1 November 1994 from the Mesaverde and Wasatch amounts to 135 MMcfd from 683 producers or an average of 198 Mcfd per well.

STUDY METHODS/APPROACH

Data Sources

This study was based entirely on public domain data and data volunteered by companies on the basis that it could be used as nonproprietary. Base data sources for this project consisted of the following:

1. **Published Information:** This consisted of reports and published literature on the basin and on various aspects of the technology utilized in exploiting low permeability gas reservoirs, not only in the Rocky Mountain area, but elsewhere.
2. **Specific Uinta Basin Reports:** These consisted of reports directed specifically at the Uinta Basin and were mainly of a research nature. These included reports in the USGS bibliography as well as reports generated by service contractors and companies in the area.
3. **Public Domain Information:** This consisted of various commercial data sources, particularly PP's NPS and WHCS files. These consisted of reported historical production data for all wells in the basin as well as digital scout ticket information.
4. **Reports to State and Federal Government Authorities:** The state and federal governments require oil and gas operators to file certain reports concerning oil and gas operations and these are part of the public record. These consist not only of forms required for drilling and completion of wells, but also include technical data such as drillstem test information, core analysis, and other useful information.
5. **Special Technical Reports:** These include submittals to state and regulatory authorities particularly in reference to obtaining tight gas sand designations for incentive pricing. Such reports are prepared by operators in support of their contention that certain areas should be designated as tight gas producing areas and hence qualify for incentive pricing. Most of such reports were made for the consideration of the Federal Energy Regulatory Commission (FERC).
6. **Proprietary Company Files:** A significant effort was directed at persuading companies to volunteer information for the use in this study. This information consisted of core, test and fracturing data and certain proprietary data and reports. Such information was solicited from companies on a voluntary basis with the proviso that it could be utilized as part of this report. We are grateful for the cooperation of many oil and gas companies for taking the trouble to provide proprietary data and to release such data for the benefit of this study.

Data Handling Procedures

Initially, a relational database was constructed of culled well information from PI's WHCS utilizing the Paradox database management system. This well-level information system was cross-referenced to allow extraction of relevant information by horizon (play) to generate data subsets for mapping and other forms of analysis. Certain WHCS and NPS data, such as formation tops, dry holes, completions, EURs, and so on, were plotted spatially, utilizing the commercially available geographic information system (GIS), GeoGraphix.

The initial data set obtained from PI consisted of the entire well population for the basin. The PI WHCS data set contained geocode information (stratigraphic data and formation tops) that proved to be fairly reliable. This information was utilized to remove oil wells and shallow penetrations which did not reach the Wasatch and also to remove wells which targeted deeper horizons within the Mancos shale and deeper.

The resulting culled data set was then further subdivided by principal play and base maps generated along the following lines:

1. **Penetration Map:** This is a map of all wells which penetrated each given play (with penetration being defined as having a total depth below the top of the play but not necessarily entirely penetrating that sequence). In addition, the USGS play boundaries are also displayed.
2. **Production Map:** This map portrays all wells reported as completed in WHCS and also portrays dry holes to give a graphic display of the distribution of well completions for each play. The fact that such completions fall inside or outside of the USGS play boundary and FERC tight gas designated areas, assisted in determining whether data culling procedures were adequate and allowed a second cull. In addition, the Scotia play boundaries are also displayed.
3. **EUR Map:** WHCS well data was cross-referenced with NPS production data via American Petroleum Institute (API) well number match. EURs performed by extrapolation of decline curves were displayed in the form of bubble maps (a circle representing each well was drawn with the area of the circle proportional to the EUR estimated for that well). This allowed a graphic display of not only the distribution of expected ultimate gas recoveries but also a visual of the relative magnitude from area to area within each play.

The base map displays allowed selection of control points for detailed analysis and rock property quantification for each play.

Production data was based upon PI's NPS file. This file was obtained for all relevant wells in the basin and was culled based upon API number matching to a culled WHCS well list. This afforded breakdown of production on a play-by-play basis and this data was loaded to Scotia's MASTER proprietary production data handling system which allowed the following:

1. The construction of a database of all production data for the basin.
2. Interfacing this database with interactive decline curve modeling software, allowing extrapolation of EURs.
3. Ability to analyze production data using Fetkovich type curve information for wells displaying a prolonged initial transient period.
4. Interface with volumetric calculations to determine recovery factors and drainage areas.

Considerable effort was expended in assembling as much core data as possible both through obtaining core analysis data directly from state records and also soliciting additional data from local operators in the area. The core data in the form of porosity, permeability, water saturation, gas saturation, and grain density measurements (conventional core analysis) was databased, correlated with principal play, and analyzed utilizing Scotia's proprietary COREPRO system. This software allows the correction of properties measured at ambient conditions in the laboratory back to in-situ conditions via a variety of techniques. A detailed discussion of core permeability corrections to in-situ conditions, together with the problems and their solutions, is provided in Appendix A of our previous report on the GGRB (Scotia, 1993).

Basic rock property information was derived from open hole wireline log data. Wireline log data was obtained for a representative grid of wells covering each play. Wells were selected not only for their geographic position but also on the basis of available data, i.e., a representative suite of logs (minimum electric survey plus ideally three porosity tools, sonic, density and neutron), and the presence of core data to allow calibration of log responses, particularly for porosity determination and correlation with log derived permeability algorithms. All logs were obtained in hard copy form and digitized using the Neuralog software in preparation for computerized log interpretation. Log interpretation was run utilizing Scotia's proprietary SLOG system, specifically the tight gas module. A detailed description of this software and of the computations performed and problem areas appears in Appendix B of our previous report on the GGRB (Scotia, 1993).

Reserves Definitions

An objective of this project was to create a base in-place gas resource estimate and estimate what proportion may be potentially convertible to recoverable reserves. As defined for the purpose of this project, "reserves" refers to gas volumes that are classified within the unproved category according to SPE definitions, plus potential undiscovered volumes considered to be commercially recoverable. Since it is of prime importance that the results of this study be understood and accepted by industry, the techniques for reserves estimation must be similarly understood and accepted. To this end, it is worthwhile to clarify the aspect of differing reserves definitions utilized by industry and to place the requirements of this project within that perspective.

The reserves definitions most commonly used in the U.S. are those published by the Securities and Exchange Commission (SEC) and the SPE in conjunction with the Society of Petroleum Evaluation Engineers (SPEE). The most recent version published by the SPE, May 1987, is comprehensively described in SPEE Monograph I dated December 1988. Definitions are subdivided into proved, probable and possible categories with each category being subjected to a status modifier with four modifiers being recognized: producing, shut-in, behind pipe, and undeveloped. For any estimate, the assignment of category reflects the degree of certainty of the estimate since the definitions of proved, probable or possible are based upon applying a test of reasonable certainty. The status assignment provides an indirect confidence measure since the classifications in the higher confidence categories will benefit from hard production data, while those in the lower confidence area will rely on more inferential data and assumptions in order to derive an estimate. These definitions are strictly deterministic. That is, a single figure is estimated as to the future recovery of oil and gas from a well, lease, field or company as a whole or an area as a whole. The fact that such estimates are imprecise is acknowledged by all professional reserves evaluators.

The use of probabilistic reserves definitions in difficult reserves evaluation situations is discussed by Caldwell and Heather (1991). The case may be made that where reserves evaluation is required for certain technology sensitive, statistical or unconventional type plays, the probabilistic approach enhances traditional reserves determination methods. The evaluation of reserves in tight gas reservoirs represents such a situation. In this situation, a variety of factors control the ultimate performance of individual wells. In many cases it is not possible to accurately measure each of the controlling factors and indeed in many cases it is not possible to determine which factors are controlling.

For the purposes of conducting this study, Scotia felt that the assignment of a single recovery factor for a play, township, section or even individual well, would not do justice to the observed variation or document the range of outcomes that are experienced. For oil companies to make planning decisions for entry into a play, such as tight gas, the range of

potential outcomes must be known and modeled in order that an economic decision weighing the reserves and reward versus the cost and risks can be made. Such expected value decisions invariably involve a range of reserves values (recovery factors) that can be anticipated and the strength of any analysis of a tight gas reserves picture must involve this distribution in order to have credibility.

These factors were recognized by the USGS in their reserves estimation deliberation. The USGS report chose to express the reserves estimates in probabilistic terms. That is, differing reserves levels were associated with differing probabilities of occurrence. Scotia believes that this concept must be perpetuated into the reserves estimation procedure as outlined below.

The SPE definitions for unproved reserves are inclusive of the categories of probable and possible. In such cases, both categories are defined in accordance with a reasonableness test as to their likely existence. That is, probable and possible reserves are defined by individual reserves estimators based upon their personal judgment as to the likelihood of existence without quantification of that likelihood. It is worthy of note that whether deterministic or probabilistic reserves definitions are applied, the base methodology used to derive the figures is identical, and that the base difference in approach between the two methodologies is the use of a consistent, non-arbitrary probability level to define probable and possible levels.

The approach taken for this report was to estimate the range of potential recoveries (recovery factors) and to express these as a distribution. These distributions are based upon actual measurements represented by the EUR of completed tight gas wells. It is felt that describing the outcome as a distribution with an associated range, standard deviation and mean, will provide a better understanding of the variability of each play rather than simply zeroing in on a single value arbitrarily defined.

It should be clearly understood that the term "reserves" as used in this report, includes volumes that extend beyond the SPE definitions of probable and possible. We have included "potential reserves" as described by Grace, Caldwell and Heather (1993). These represent volumes that are considered commercially recoverable but have not been "discovered."

The question of "discovered" in unconventional resources is complicated. In normal evaluations, the proportion of a reservoir considered discovered is based upon well control and the terms proved, probable and possible often equate to radii of confidence surrounding well data points. Water contacts and reservoir boundaries define the limits of the discovered volume.

For unconventional tight gas resources, the reservoir is complex in its definition.

Massive sections of gas-bearing rock exist with no defined fluid contact or obvious reservoir boundary. Producibility varies markedly from area to area and location to location based on a variety of factors, many of which are extremely difficult to measure or predict. This renders the radius method inoperable and poses the larger question of how to define "discovered." These considerations have prompted the broadening of the term "reserves" to encompass the proportion of the gas resource that may be potentially convertible to commercially productive reserves by adding the "potential reserves" category to the standard probable and possible definitions.

Rock Properties and Volumetrics: Gas In-Place

An examination of reserves or reserves potential must commence with an initial gas in-place estimate. For the purpose of reserves estimates, the USGS divided the Mesaverde formation into three plays using thermal maturity (present vitrinite reflectance, R_o) maps and depth. Similarly, the Wasatch formation was also subdivided into three plays based on thermal maturity in the underlying Mesaverde and development of the formation across the basin. The following table compares the USGS and Scotia play and subplay names:

TABLE 5
PLAY NAME COMPARISONS

USGS PLAY	PLAY	SCOTIA SUBPLAY
Play 2015 & 2016 Gas-Saturated Wasatch Formation (east and west of Green River)	Wasatch	Gas-Saturated
Play 2017 Gas With Water Contacts: Wasatch Formation	Wasatch	Gas-Water Transitional
Play 2018 Basin Flank Gas-Saturated Mesaverde 15,000'	Mesaverde	Gas-Saturated $R_o > 1.1 < 15,000'$
Play 2019 Cretaceous Mesaverde Gas-Water Transitional	Mesaverde	Gas-Water Transitional $R_o 0.70-1.1$
Play 2020 Gas-Saturated Deep Synclinal Low	Mesaverde	Gas-Saturated Deep Synclinal $>15,000'$

For the purpose of determining gas in-place resources, the USGS play outlines were modified as follows:

- USGS Play 2015** Expanded to the north to encompass Wasatch production in that area and combined with USGS Play 2016.
- USGS Play 2016** Combined with USGS Play 2015.
- USGS Play 2017** Limited to only those areas where Wasatch production had been demonstrated outside of the R_o 1.1 line as drawn on the base of the Mesaverde group.

- USGS Play 2018** Expanded to include rock volume excluded from USGS Play 2020 for reasons described below.
- USGS Play 2019** Expanded to the east to encompass Mesaverde production outside the R_o 0.7 line as drawn on the base of the Mesaverde group.
- USGS Play 2020** Reduced in size since much of the play as drawn included rock situated above 15,000 feet when using the structure map drawn during this study.

Gas in-place resources were calculated for each play as follows:

1. **Net Reservoir Thickness Counts:** Sandstone thickness was counted for each play by applying a 50% V_{clay} cutoff to the gamma ray curve. Definition of reservoir quality rocks (that portion of the sandstone thickness expected to contribute to reserves) for use in this study was achieved by applying a suite of cutoffs including porosity, water saturation, V_{clay} and permeability, developed for each play from a comprehensive evaluation of core, log and well test data, and published literature. The cutoffs ranged as follows:

TABLE 6
LOG-DERIVED PAY CUTOFFS

PLAY	V_{CLAY} (%)	POROSITY (%)	WATER SATURATION (%)	PERMEABILITY (md)
Wasatch	35	4.0-10.5	60.0-65.0	0.001
Mesaverde	35	4.5-10.0	60.0-65.0	0.001

2. **Volumetric Mapping:** Gross thickness maps were derived from subtraction of the structure maps drawn on the top and base of each play. Sandstone/gross and pay/gross ratio maps were prepared along with the gross maps to generate sandstone and pay thickness maps. Use of net/gross trends was particularly important in the Mesaverde where the majority of well control points represented only partial penetrations of the play.
3. **Porosity and Water Saturation:** Formal digital tight gas log interpretation, calibrated to corrected core data was used where possible to calculate rock properties on a foot-by-foot basis. Appendix B of our GGRB report (Scotia, 1993) details the methodology. This technique provided detailed porosity and water saturation data and more importantly, provided the distribution of these parameters and their interrelationship. Two sets of porosity and water saturation distributions were generated. The first corresponds to the larger sand count generated using a 50% V_{clay} cutoff, the second

corresponds to the net reservoir rock thicknesses defined during this study. Several observations can be made as follows:

- a. Porosities were distinctly skewed such that the lower porosities form the bulk of the distribution. These distributions are discussed by play later in this report.
 - b. Porosity distributions corresponding to the pay thickness for the Wasatch and Mesaverde plays are similar. Likewise, those corresponding to the sandstone thicknesses are relatively similar. However, a larger percentage of the Wasatch sandstone thickness (7% versus 4%) is estimated to be of sufficient reservoir quality to be counted as pay.
 - c. Porosities in the deeper gas-saturated plays are generally lower than those in the gas-water transitional plays. However, further porosity reduction below about 8,500 feet md appears negligible.
 - d. Water saturations in the lower porosity rocks were high, tending towards 100%, as porosities reduced toward zero. Since the porosity is skewed in favor of the lower values, a significant portion of the rock volume has high water saturations.
 - e. Water saturations corresponding to the sandstone thicknesses in the deeper gas-saturated plays are generally lower than those in the gas-water transitional plays.
 - f. Application of the cutoff suite resulted in a significant reduction in reservoir rock thicknesses.
4. FVF: In this study, reservoir temperatures were calculated for each play using two temperature gradients as follows:

West of the Green River $90 + 0.011 \times \text{depth}$
East of the Green River $50 + 0.02 \times \text{depth}$.

Reservoir pressures were calculated for each play using two gradients as follows:

Overpressured areas in Altamont Bluebell and northeast Natural Buttes:	0.623 psi/foot
Normally pressured areas:	0.465 psi/foot.

Each gradient was valid for both plays.

5. Calculation of GIP: During this study two estimates of resource in-place were made. The first was a redetermination of the "total resource" using the sandstone thicknesses (50% V_{clay} cutoff) and the corresponding rock property distributions developed from log analysis. The second was a determination of that portion of the total resource which would be expected to contribute to reserves. This was estimated using the pay thicknesses (porosity, V_{clay} , water saturation and permeability cutoffs) and the corresponding rock property distributions developed during this study. The difference between these two figures represents that portion of the "total resource" which is not expected to contribute to reserves.

Both the sand thickness and Scotia's net reservoir rock thickness maps were depth-gridded to segment them into 500 foot thick depth slices. Based upon well control, log-derived rock properties within each 500 foot depth slice were compiled as distributions of porosity, water saturation and permeability. Utilizing the appropriate depth, FVFs were calculated as described above, and GIP for each 500 foot depth slice for both the sandstone thickness and pay thickness maps was calculated deterministically.

6. Results: The following table presents the results of the GIP estimate by play and subplay. Resources calculated using the pay thickness maps are listed in the "Technologically Viable" column. Resource presented in the *Technologically Nonviable* column were derived by subtracting the *technologically viable* resources from the resources calculated using the sandstone thickness maps (total resource). Explanation of the *technologically viable* and *nonviable* terms is provided along with other resource terminology later in the report.

TABLE 7
RESOURCE BREAKDOWN BY SUBPLAY AND TYPE

PLAY/SUBPLAY	TECHNOLOGICALLY VIALE Tcf	TECHNOLOGICALLY NONVIALE Tcf	TOTAL
Wasatch			
Gas-Saturated	4.5	35.2	39.7
Gas-Water Transitional	2.6	17.6	20.2
Mesaverde			
Gas-Saturated Deep Synclinal > 15,000'	6.9	40.9	47.8
Gas-Saturated $R_o > 1.1$ & < 15,000'	37.7	163.0	200.7
Gas-Water Transitional R_o 0.70-1.1	19.0	68.1	87.1
TOTAL	70.7	324.8	395.5

Evaluation Difficulties

Basic volumetric and recovery factor calculations are complicated by certain physical properties peculiar to tight gas reservoirs. Recognition of these factors is important in attempting to predict the performance of tight gas wells.

1. Study of core data indicated that in many cases porosity and permeability are poorly correlated, if correlated at all, particularly in the lower porosity ranges.
2. Distributions of log-derived and measured porosities tend to be heavily skewed towards the lower porosity ranges.
3. Because the bulk of porosity development is of secondary origin, much of such porosity is poorly connected in a conventional sense (i.e., via normal pore throats), but rather requires connection via an anastomosing network of natural fractures, micro-fractures and capillaries.
4. Due to the poor relationship shown in most plays between porosity and permeability, selection of the most porous zones for completion attempts may not necessarily encounter the greatest natural fracture permeability. However, since it has been shown that frac treatments in the basin achieve more significant height growth than has been previously modeled, it is likely that most fracs do not stay within the perforated zone and may in fact grow by up to several hundred feet above and/or below into adjacent horizons. This opens the possibility of accidentally fracturing into the more naturally permeable sections. This has been observed in some GGRB, Piceance and Uinta wells which produce considerably more than can be attributed to the perforated zone. In such situations contributions from overlying and underlying reservoirs can be inferred.
5. Examination of frac, DST and production data within various areas and from play-to-play indicate that lateral continuity of the pay zone of interest is of extreme importance in controlling long-term well productivity. Where sands have a greater degree of lateral continuity, the ability to place a successful frac treatment is much enhanced. Where sands are lenticular or display lateral continuity only in given directions (e.g., channels), the ability to create a successful commercial completion is reduced. In such cases, directions of maximum in-situ stress and maximum direction of geological continuity must be fortuitously oriented to be able to exploit the natural directions of more favorable reservoirs. In a similar fashion where natural fracturing within the reservoir is not oriented favorably with respect to directions of maximum in-situ stress, frac results can be variable or disappointing. The subtleties of these geological and geomechanical properties are difficult to measure and predict and complicate the process of effecting a commercial completion. That is, even where log responses and

log analysis indicate excellent pay potential in comparison to logs in wells which have been superior producers, the inability to predict and quantify lateral variation may render completions as marginal or noncommercial.

Quantifying Recovery Factors

In considering conventional gas reservoirs, the subject of drainage and spacing is not so much at issue as when dealing with tight reservoirs. For conventional reservoirs, well spacing can be decided upon without too much concern for areal reservoir continuity such that each well can be assumed to adequately drain the reserves within its no-flow boundaries. These boundaries surround the well at a position dependent upon the offtake rates of surrounding wells and the variability of reservoir characteristics between wells. In this scenario, recovery factor is independent of well spacing, whereas per well recoverable reserves and the rate of recovery for a given reservoir are very dependent on well spacing. Therefore, the concept of a reservoir-wide recovery factor has validity for conventional reservoirs.

In tight gas reservoirs, the ability of a well to drain a given area is dependent upon the amount and effectiveness of naturally occurring permeability (matrix and fracture), its ability to interconnect the porosity within the tight formation, and the effectiveness of a fracture treatment in connecting such natural permeability to the wellbore. Fracture treatments generate fractures which generally propagate in the direction of maximum horizontal stress, and result in circular to ellipsoidal shaped fractures oriented in a vertical or sub vertical plane. Effective drainage by the frac'd wellbore in plane view will tend towards an elongated ellipsoidal pattern as opposed to a circular drainage radius, and the areas drained by individual wells will tend to be proportional to the dimensions of the effective artificial hydraulic fracture.

In expansion drive gas reservoirs, the recovery factor of GIP is proportional to the degree of pressure depletion that can be effected by the well down to its economic limit. The recovery factor will be the P/Z at original pressure, minus the P/Z at abandonment, divided by the P/Z at original pressure. In other words, if 85% of the P/Z value is achieved by the time a well has produced to its economic limit, then the recovery of accessed GIP will be 85%. The economic limit of course will depend upon that point at which revenues no longer exceed expenses and will be a function of prices, royalties, production taxes and operating expense. For any given well, the ability to produce is a direct function of surface versus bottomhole flowing pressures and it can be argued that with all else being equal, all gas wells will recover approximately the same proportion of GIP (that is, will be produced to the same pressure depletion) and hence have approximately the same final recovery factors.

The issue at hand is not so much what the pressure at abandonment is, but rather what area is being accessed in terms of reservoir drainage down to this pressure. Since tight gas

wells may drain only a small area, the recovery factor of GIP within the regulatory spacing limit versus what proportion of that spacing limit is actually drained is the key issue. By example, if a gas well is drilled on a regulatory 320 acre spacing and effectively has a 75% recovery over a drainage area of 40 acres, then the recovery factor could be expressed as the effective recovery of GIP on the entire 320 acre unit ($75\% \times 40/320$), or 9.4% recovery of GIP.

The computation has greater significance than simply determining the recovery factor based upon a regulatory spacing. If in the above example the well was economically viable draining only 40 of the 320 acres, then an additional seven well locations would be available by downsizing the spacing unit to 40 acres, whereby similar recovered volumes could be anticipated. In other words, if the spacing unit was not reduced, 87.5% of the potentially recoverable gas would be bypassed by drilling on a 320 acre spacing. Many examples of bypassed reserves such as this occur in tight gas provinces. Cipolla (1992) reports virtually identical per well recoveries from wells drilled on an initial 640 acre program that was later down-spaced to 320 acres and then 160 acres. Resulting recovery on the 160 acre spacing averaged 61% of GIP and resulted in reserves growth of 190 Bcf.

The quantification of recovery factors thus becomes a function of well drainage area vis-a-vis the spacing unit area dictated by regulatory field rules. The area difference (spacing less drainage) is proportional to the undrained or bypassed gas that would be available to a reduced spacing (infill drilling) program.

Economic Basement Determination

Economic considerations play a role in the distinction between reserves and resources. For resources to qualify for potential conversion to reserves, such resources must be producible at rates and with ultimate volumes that will repay the cost of drilling and completion and provide a normal profit. For the purposes of this study, production which generates an operating income stream discounted at 10% (PV10) that is equal to drilling and completion costs represents the break over point for commerciality. The present value calculation assumes a royalty of 18.75%, severance and ad valorem taxes of 7.15%, operating costs of \$1,000/month, and a \$2.00/Mcf wellhead gas price. Drilling costs are a function of depth with separate relationships corresponding to dry hole cost and total completed well cost. The \$2.00/Mcf gas price was used as a requirement of this study. The effect of other prices on the *economic basement* calculation is described in Appendix A.

It should be clearly stated that the economic cutoff for qualification of reserves as used herein represents a payout of drilling costs plus a profit motivation. In practice, reserves are considered commercial if they produce sufficient income to cover operating costs without consideration of whether the capital expenditures incurred to drill and put wells on stream are ever paid out. That is, while operators do not intentionally drill wells that do not pay out,

things do not always turn out as planned. Such situations are commonplace and are not predictable until after the wells have been put on stream. While numerically non-payout wells may number 60% of the total producing well population, they contribute about 10% of the total EURs.

To acknowledge the economic requirement for reserves qualification, the term *economic basement* is introduced. This term recognizes that drilling costs increase with depth and hence the reserves that must be found to repay those costs must also increase with depth. *Economic basement* as a concept represents a depth where the curves cross. That is, where the risk weighted average reward equals the risk weighted average cost. Below this depth the probabilities are that expense will outweigh reward. Above this depth the reverse is true. *Established* resources are those located above *economic basement* and those located below are termed *nonestablished* resources.

Economic basement in the context of a resource/reserves evaluation represents a convenient break point for separation of the known from the unknown. In practicality, most of the productive horizons are situated in the shallower depth ranges, while resources are distributed variously with depth from play-to-play. In all cases, knowledge, development, performance, and control for the deeper zones is inferior to the shallower. As a result, the extrapolation of models developed for the better controlled shallow horizons into the deeper zones is not warranted unless an analogy can be developed that is justified by real data.

Determining *economic basement* depth for each play was approached as follows:

1. Determine Reward Expectation. In order to justify the expense of drilling, the target reserves must be of sufficient magnitude to provide a profit incentive. This magnitude must be sufficient to also outweigh the dry hole risk component. Since these plays are relatively new (generally less than 20 years old) and drilling density low, the distribution of existing EURs for each play was used as the model for future discovery expectation. It is not known whether future results will have the same distribution or whether a "depleted" distribution would be more representative. This study used the existing per well EURs as the model for future expectation. This approach is more likely to err on the optimistic side.

Sampling of the EUR distribution assumed a program (multi-well) approach. That is, rather than taking the median value which would be the expectation for a single well, the distribution was split into five units, each representing 20% of the EUR population and each unit was sampled at its midpoint leading to P10, P30, P50, P70, and P90 samples, each having an equal probability of occurrence. The reward is then calculated by cash flow construction and determining a PV10 for each sample, net of taxes, royalties, operating costs and drilling and completion costs.

2. Determine Dry Hole Risk. Historical drilling statistics were compiled to determine the historical dry hole frequency. This consisted of identifying all wells drilled for the play and subdividing those wells based upon the total depth (TD). Wells which TD'd in a play were regarded as having that play as their objective. Wells were further subdivided as to whether they fell within the *demonstrated* portion of the play. Those that fell outside the *demonstrated* area were excluded. Dry hole percentage was then determined by dividing total dry holes by total wells in the play. Note that a significant number of completions were made that failed to produce commercially and were "worse than a dry hole" since the expense of a completion and frac was incurred. Such failed completions were accounted for in the EUR distribution and were handled as negative cash flow components. The argument may be made that discrimination should be made between well classes (exploration versus development) since success levels are typically higher when considering development wells. Again, due to the immature nature of the play and the requirement for frac treatments to be successful (a significant element of mechanical risk), the distinction between an exploration (wildcat) and a development well becomes hazy. We elected to simplify the model by selecting a success ratio based on historical drilling data that typifies the current status of the play under consideration. This will be weighted towards development drilling success levels in the more mature areas and towards exploration or wildcat success level in less known or less developed portions of the play.
3. Construct Expected Monetary Value (EMV) Analysis. The EMV analysis seeks to determine the *economic basement* depth as being that point where the EMV is zero. That is, above that depth, EMV is positive and risk weighted rewards are greater than risk weighted costs. Below that depth the cost of failure is greater than the risk weighted reward and EMV is negative. In summary, the EMV calculation takes into account the expected dry hole probability, the expected distribution of EURs that will be encountered, and the drilling cost environment versus depth. Figure 10 illustrates this calculation for a single depth. *Economic basement* represents that depth where the EMV equals zero.

The *economic basement* concept seeks to determine that depth at which the reward (profit) expectation no longer supports the risk (cost). This forms a logical dividing point for each play for performing reserves calculations. *Economic basement* is a dynamic depth. It is deepened by increasing gas prices, incentives, reduced drilling cost, higher success levels and larger finds. The reverse also applies. Since *economic basement* as a concept is dynamic, changing as its defining parameters change, the resources in the *established* and *nonestablished* categories will also be dynamic.

ECONOMIC BASEMENT DETERMINATION
PLAY: WASATCH UINTA

Figure: 10

BASE PARAMETERS:			
6150	DEPTH (FEET)	2.0%	PERCENT DRY
29	DRY HOLE \$/FT	1500	P10 EUR (MMCF)
74	COMPLETED \$/FT	720	P30 EUR (MMCF)
178	DRY COST (\$K)	450	P50 EUR (MMCF)
455	COMPL COST (\$K)	230	P70 EUR (MMCF)
0.78	AVG PV10, \$/MCF	48	P90 EUR (MMCF)

EMV CALCULATIONS		PERCENT	UNRISKED	RISKED
COMPLETIONS	P10	19.6%	715	140
	P30	19.6%	107	21
	P50	19.6%	-104	-20
	P70	19.6%	-276	-54
	P90	19.6%	-418	-82
DRY HOLES		2.0%	-178	-4
EXPECTED MONETARY VALUE (\$K)				1

Reserves Calculations

Starting with the resource itself, the following steps were employed in estimating reserves:

1. Creation of Basic Resource: This has previously been described, and consisted of applying a sophisticated porosity, water saturation and FVF model to the sandstone rock volume.
2. Identification of a *Technologically Viable* Reservoir: Based on log analysis, pay quality zones were identified, isopached and GIP calculated by depth slice.
3. Removal of *Technologically Nonviable* Resources: By subtracting the pay quality GIP from the total resource GIP, the GIP in nonpay quality rocks was determined. This quantity is termed *technologically nonviable* since current frac technology has failed to yield a commercial completion in such reservoirs. Such reservoirs will have in-situ permeabilities below 0.001 md in general. It is important to identify and quantify this portion of the total resource since future technology improvements will move portions of it into the *technologically viable* category.
4. Removal of *Nondemonstrated* Resources: A significant fraction of the *technologically viable* resources is located in geographic areas or stratigraphic units that have not established any commercial production or about which very little is known. That is, while sands may calculate as potentially productive based on log analysis, such sands have either not been tested or have been tested but with poor results and were thus included within the *nondemonstrated* category.

Until such time as a technology is developed to successfully exploit the *nondemonstrated* category, such resources will be excluded from consideration from a reserves quantification viewpoint.

5. Removal of *Speculative* Resources. After removal of *nondemonstrated* and *technologically nonviable* resources, the remaining volume represents *demonstrated* resources. *Speculative* resources are that portion of *demonstrated* resources that lie in deep basinal areas below *deepest commercial production*. Their quantification depends upon extrapolation of geological mapping and has a significant degree of associated uncertainty. Because of this uncertainty, and lack of a production analog, *speculative* resources were excluded from consideration for reserves quantification purposes.
6. Subdivision Based on *Economic Basement*: The *economic basement* depth conveniently separates resources which on average represent economic targets from those which do

not. This does not imply that all resources above *economic basement* are convertible to reserves via application of an appropriate recovery, nor does it imply that all resources below *economic basement* will contain no potential reserves. Rather, *economic basement* represents the break over point from one reserves and risk environment to another. The aspect of risk (drilling and reserves quantity) must be considered in order that the commerciality criterion to qualify as reserves is satisfied.

7. Derivation of Risk and Recovery Models: After all of the constraints described above have been applied, the remaining volumes represent *demonstrated* resources distributed in accordance with regional isopachs. It is recognized that the entire regional isopached volume will not all be uniformly productive. Dry holes exist within the mapped area as do productive wells, some of which are commercial (have reserves) and some of which are noncommercial (not qualifying as reserves).

The recovery factor model thus requires not only a percent recovery of GIP factor, but must also take into account a factor representative of dry holes and noncommercial completions. This "non-reserves" factor represents that proportion of the *demonstrated* resource's isopached volume that will not be commercially productive for a variety of reasons. Such reasons could include lateral discontinuity of reservoirs, unfavorable stress conditions for frac treatments, absence of natural fractures, etc.

The recovery factor model developed for this study was constructed as follows:

- a. Determine Base Recovery Factor. For each well in the sample, a base recovery factor was derived from initial and final static bottomhole pressure. The latter was assumed to be 500 psi, which is probably optimistic and represents a minimum abandonment pressure for economical production. However, no actual abandonment pressure measurements were available. This assumed abandonment pressure resulted in base recovery factors varying from 50 to 90% and averaging 86%.
- b. Determine Average Drainage Area. Based on a sampling of completed tight gas wells, average drainage areas were calculated using the EUR from production performance analysis, the recovery factor and the volumetric parameters for the perforated interval based on log analysis. This result was checked against the average drainage area determined by Fetkovich type curve analysis on wells exhibiting a significant initial transient period with a reasonable match.
- c. Determine Range of Drainage Area. Drainage area was plotted versus EUR and a log-log regression performed (Figure 11). The scatter on this plot is due

to differences in petrophysical properties, mostly net pay thickness. By drawing lines that are parallel to the regression fit that effectively bracket all data points, an upper, most likely and lower relationship for EUR versus drainage area was determined.

A minimum commercial volume was calculated representing the EUR that resulted in an operating income stream with a PV10 equal to drilling and completion costs at the representative depth for the play being considered. Using this EUR, the upper, most likely and lower drainage areas were determined graphically as shown in Figure 11. Note that the minimum economic drainage areas can be quite small due principally to significant perforated pay thickness. In this example, the following were derived for a minimum economic EUR of 460 MMcf.

**EXAMPLE MINIMUM ECONOMIC
DRAINAGE AREA MODEL**

Upper Area	110 Acres
Most Likely Area	36 Acres
Lower Area	13 Acres

- d. Determine Noncommercial Fraction. The distribution for the fraction of wells expected to be noncommercial was determined by constructing a probability plot of drainage areas and using a smoothed correlation, reading off the percentage of drainage areas smaller than each of the areas representing the upper, most likely and low areas as shown on Figure 12.

EXAMPLE NONCOMMERCIAL FRACTION MODEL

Upper Area	77%
Mostly Likely Area	44%
Lower Area	18%

For example, for the most likely case, there is a 44% probability that a well will drain less than 36 acres and hence be noncommercial.

FIGURE 11
Recovery Factor Model
Drainage Area Versus EUR

FIGURE 12
Drainage Area Probability Plot
Noncommercial Fraction Determination

- e. **Determine Dry Hole Fraction.** This represents the fraction of the resource volume condemned by dry holes. Historical drilling data from the WHCS was used to establish dry hole percentage to date. This data was used as a guide and was judgmentally rounded to reflect future dry hole expectation. For plays or portions of plays with an established drilling history, the dry hole statistics will tend to reflect development well drilling success ratios. Where less information is available and where commercial development has not been established, or is in its infancy, the statistics will reflect exploration well success ratios. The dry hole factor thus serves a dual role, reflecting not only historical success, but also maturity of the target in question.
- f. **Recovery factor (RF)** was the net of dry hole fraction (DHF), noncommercial fraction (NF), and base recovery factor (BRF), combined as follows:

$$RF = (1-DHF)(1-NF)(BRF)$$

EXAMPLE RECOVERY FACTOR CALCULATIONS

	Dry Hole Fraction = 0.02
	Base Recovery Factor = 0.81
Maximum	$(1-0.02) \times (1-0.18) \times 0.81 = 0.65$
Most Likely	$(1-0.02) \times (1-0.44) \times 0.81 = 0.44$
Minimum	$(1-0.02) \times (1-0.77) \times 0.81 = 0.18$

The maximum, most likely and minimum RFs defined a triangular distribution which was applied along with distributions for porosity, water saturation (as a dependent variable to porosity), FVF, and a single deterministic value for rock volume in a Monte Carlo simulation to derive a recoverable gas estimate expressed as a distribution.

Porosity and water saturation distributions that were used for each play are discussed and graphically displayed in the sections on each play.

8. Application of the Model. For model application, each play was segmented into subplays based on level of thermal maturity and in the case of the Mesaverde, depth. Each subplay was characterized by its own porosity and water saturation distributions. Then each subplay was segmented into two basic depth slices.
 - a) Top of play to *economic basement*.
 - b) *Economic basement* to deepest commercial production.

Each depth slice was characterized by its own noncommercial fraction and recovery factor distribution. As with any estimate of reserves, such estimates are subject to revision as ensuing developments provide additional data.

As summarized earlier, Scotia's combined volumetric/probabilistic approach to estimating tight gas reserves differs somewhat from the USGS nonvolumetric probabilistic approach, and has resulted in a considerably smaller estimate. Table 8 compares the Scotia reserves by play/subplay with those estimated by the USGS. A third reserves estimate, that of the 1995 National Assessment of the United States Oil and Gas Reserves, is also presented. The USGS and 1995 National Assessment Reserves were both calculated using the UNCLE probability model, using the same basic input parameters. The different results are due to the following:

1. Reservoirs within the Wasatch and Mesaverde gas-water transitional plays (USGS plays 2017 and 2019 respectively) were reclassified as "conventional" based on certain "changes in economic, experience and technology factors" (Fouch, 1992). As a

consequence, 3.1 Tcf of reserves were dropped from the National Assessment list of unconventional reserves and reconsidered elsewhere.

2. An error in the reserves calculation for the Wasatch gas-saturated play (USGS plays 2015 and 2016 combined) of 3.1 Tcf, which appeared in the USGS estimate, was subsequently corrected for the National Assessment.

TABLE 8
UINTA BASIN RESERVES COMPARISON

PLAY	USGS (Tcf)	SCOTIA (Tcf)	1995 ASSESSMENT
Mesaverde Gas-Saturated Deep Synclinal > 15,000'	0.57	* 0.00	0.57
Mesaverde Gas-Saturated $R_o > 1.1$ & < 15,000'	3.78	0.61	3.78
Mesaverde Gas-Water Transitional R_o 0.70-1.1	1.48	0.97	**0.00
Wasatch Gas-Saturated	5.75	1.14	2.65
Wasatch Gas-Water Transitional	1.62	0.89	**0.00
TOTAL	13.20	3.61	7.00

* *Non-Demonstrated* play, therefore no reserves are calculated

** Play not considered

Some of the possible differences in reserves estimated by Scotia and the USGS are explained below:

1. The USGS reserves estimate for the Wasatch gas-saturated play (USGS plays 2015 and 2016 combined) once corrected, is roughly twice that estimated by Scotia. The bulk of this difference may be attributed to approximately half of the play being considered as *nondemonstrated*. Reserves are estimated from *demonstrated* resources only. This rather large *nondemonstrated* region is partially attributed to the general lack of evidence of natural fracturing necessary for migration of gas from the underlying Mesaverde.
2. Scotia's lower reserves estimate for the Wasatch gas-water transitional play (USGS Play 2017) can again be attributed somewhat to the large percentage of play area considered as *nondemonstrated*. As discussed, this reserve was dropped from the National Assessment.
3. The USGS reserves estimate for the Mesaverde gas-saturated play above 15,000 feet (USGS Play 2018) is roughly six times larger than Scotia's estimate partly because success ratios and EUR distributions were derived from more prolific Piceance Basin wells. The USGS reasons that the Mesaverde geology of the Uinta Basin is similar to

that in the Piceance Basin, ergo its reservoir quality and production characteristics, are also similar. Scotia opted to use an EUR distribution throughout the Greater Natural Buttes area, both in the gas-saturated and gas-water transitional plays. Much of the reserves difference can also be attributed to the bulk of the gas-saturated play area being considered as *nondemonstrated*.

4. The reserves difference in the Mesaverde gas-water transitional play (USGS Play 2019) can also be attributed to different EUR distributions and large portions of the play area being considered *nondemonstrated*. We would also argue that the limited well log, test and production data available for reservoirs in this play support their classification as unconventional rather than conventional.
5. The total Mesaverde gas-saturated play below 15,000 feet (USGS Play 2020) is considered *nondemonstrated* at this time. Consequently, no reserves were calculated for this play.

BASIC TECHNICAL PARAMETERS

Log Interpretation

Statement of Problem: Comparison to Conventional

Use of conventional log interpretation techniques within tight reservoirs meets with only limited success in accurately defining rock properties. This results from the fact that the normal logging tools are operating outside their optimal design range and the fact that tight reservoirs have particular characteristics which differ significantly from conventional gas reservoirs. These include variable invasion profiles causing variable gas saturations within the invaded zone, considerable uncertainties in formation water resistivity, variable grain densities and the presence of clay minerals, both original and authigenic, distributed in various geometries. Special log interpretation techniques are required to account for these factors as detailed in Appendix B of our GGRB report (Scotia, 1993).

Some of the more successful methods for dealing with log interpretation problems in tight reservoirs are those developed by Kukal (1981 and 1984). These methods are included within Scotia's proprietary log interpretation program, SLOG. The objective of the log interpretation exercise was to derive a set of rock properties including sand thickness, net gas pay, effective porosity, water saturation and a log-derived permeability that could be used to map the distribution of gas and in volumetric calculations of GIP.

Formation Water Resistivity

Formation water salinity data available from a variety of sources indicate wide ranges of R_w , making the determination of a blanket R_w for a given play frustrating and problematic at best. The determination of R_w is complicated by the fact that tight reservoirs produce little if any water, and that which is produced often contains condensation. R_w estimates from the spontaneous potential (SP) curves are generally unreliable due to poor development of the SP log in tight gas sands and the absence of a definitive wet clean reservoir for calibration purposes. This also limits the R_{wa} and Pickett plot techniques. Attempts to post and contour available R_w data showed no particular pattern and confounded any attempts to contour the exhibited variation.

The R_w used on a well by well basis was determined via Kukal's (1984) iterative method as described in Appendix B of our GGRB report (Scotia, 1993), and then compared against R_w values reported in the literature at reservoir temperature. In selecting a final R_w for use, generally the lower of these two values was used. Kukal's

(1984) equation, which was derived from a combination of the neutron and density response equations, iteratively solves for S_{dn} (the saturation of the zone investigated by the neutron and density tools). The equation is reversed to solve for R_w . Use of S_{dn} to derive an appropriate formation water resistivity was restricted to sands which were relatively clean (low V_{clay}), in gauge, ideally where a neutron-density gas effect is apparent and where $S_{xo} - S_{dn}$ is a maximum when S_{xo} is not equal to S_w .

S_{dn} and consequently R_w derived from S_{dn} , decreases as gas gravity increases. To account for changes in gas density with depth on a basin scale, a transform was developed for the Piceance Basin and used to adjust density and neutron responses to hydrocarbons and as a function of change in depth.

$$R_{hoh} = a + b \times \text{depth} + c \times \text{depth} \times \ln \text{depth}, \text{ Where:}$$

R_{hoh}	=	Density response to hydrocarbons
a	=	-0.03010759
b	=	-0.000129914
c	=	-1.1787 E-05
P_{hinh}	=	$R_{hoh} \times (9 \times / (12 + x))$, Where:
P_{hinh}	=	Neutron response to hydrocarbons
x	=	Hydrogen-carbon ratio (3.82)

Porosity

Porosity determination in tight sands must take into account several particular physical properties that influence not only the logging tools themselves but also the interpretation methods for deriving an effective porosity measurement. These effects include:

1. Variable gas saturation in the invaded zone or absence altogether of an invaded zone producing an inconsistent density and neutron log response to hydrocarbons.
2. Sonic log values are suspect in tight sands since the sonic log will tend to record primary porosity and bypass secondary porosity. In many cases tight sands have a predominant porosity network of a secondary origin that may be bypassed via sonic log readings.
3. The presence of clay minerals and abundant lithic fragments causes grain

densities to vary and hence matrix values used to derive log porosities will also vary.

4. The overpressured nature of the sediments in certain areas in the basin and the normal practice of drilling wells balanced or under balanced as well as the generally fractured nature of the formation, can cause severe hole caving. This markedly affects the pad tools (density log) and can also affect other log measurements where boreholes are particularly rugose.

Porosities were derived from log data using the methods of Kukal (1984) developed specifically for tight gas sands. Kukal's (1984) equation iteratively solves for S_{dn} to correct for porosity tool gas effects. Details of these calculations are included in Appendix B of the GGRB report (Scotia, 1993).

Water Saturation

Due to the presence of abundant authigenic clay minerals, a shaly sand approach was taken in evaluating water saturations involving use of the total shale (Simandoux) equation. While recent work in the basin has indicated that the use of a dual water or Waxman-Smiths type of approach has been effective in obtaining reasonable results, the general lack of cation exchange capacity data except in extremely local areas limited the use of such techniques for the purposes of a project of this scale.

Archie exponents used in determining water saturation were investigated from a variety of sources and after considerable experimentation and consideration of net overburden (NOB) effects, the following were selected as representative:

$$\begin{array}{rclcl} a & = & 1 & & \\ m & = & n & = & 2.0 \end{array}$$

Permeability From Log Data

Attempts to derive permeability from log information are not usually highly successful. Correlations based on core to log relationships can be locally valid, however, extrapolating these into other areas or other formations often introduces the potential for considerable error. The presence of natural fracturing can also provide a separate and unquantifiable permeability overlay to the natural fabric of the tight reservoirs.

The equations developed by Kukal (1984) based on his study of samples from the MWX wells in the Piceance basin provided a reasonable permeability approximation. Two equations were used: the first required input values of porosity, water saturation and clay volume; the second equation eliminated the saturation fraction which can have a fairly weak correlation with permeability in low permeability rocks. Log permeabilities derived from this study are displayed in the discussion of each individual play.

Permeability

The single most important factor and the single biggest unknown in dealing with tight reservoirs is permeability. By definition, tight reservoirs are defined as having a natural in-situ permeability to gas of less than 0.1 md. The effective range for completion of tight reservoirs, based principally on the current frac technology, is between 0.001 and 0.1 md. At permeabilities below this range, fracture treatment is commonly not successful and above this range is commonly not necessary.

Permeability in tight reservoirs is not only low but complex in its source. Because the sediments are tightly compacted, cemented and contain abundant secondary mineralization and grain dissolution, the producing mechanism in the reservoir is quite different from that of a conventional reservoir. Rather than having discrete pores and pore throats, the porosity available within the tight sand may be distributed in a non-uniform fashion and connected by an anastomosing network of micro-fractures and fine capillaries. As such, a standard core plug sampling of cores from tight sands may not do justice to the range of parameters that may be expected from the gross sand itself and also may have permeabilities so low as to be not measurable utilizing standard core analysis techniques.

In addition, tight sands are markedly influenced by the effects of unloading and require significant corrections to convert surface ambient measurements to in-situ conditions as discussed in Appendix A of our GGRB report (Scotia, 1993).

Scotia's proprietary COREPRO software was utilized to process a large database of core information collected for the Uinta Basin. The COREPRO software performed the necessary corrections for overburden and the corrections for gas slippage (Klinkenberg) and brine saturation.

Corrections to In-Situ Condition

Prior to the development of automated equipment able to measure porosity and permeability at NOB, in use in many laboratories today, measurements were taken at ambient conditions. Essentially all the core data available for this study was measured

at ambient conditions and consequently required the following corrections to represent in-situ conditions.

1. Overburden corrections to restore porosity and permeability to in-situ conditions. NOB corrections to porosity were developed using core measurements from the MWX wells as a function of both changes in porosity and NOB. Because of the increase in magnitude of correction with decreasing porosity, the data set was split into samples greater than and less than 5% porosity, this being the approximate cutoff between reservoir and non-reservoir rock. Correction transforms taken from plots of percent reduction in porosity versus overburden pressure are as follows:

$$\begin{aligned} \text{Porosity} < 5\% \quad y &= -2.3641 + 0.1566 \sqrt{\text{NOB}} \\ \text{Porosity} > 5\% \quad y &= -1.2781 + 0.0904 \sqrt{\text{NOB}}, \quad \text{Where:} \end{aligned}$$

y = percent of porosity reduction.

A normalizing factor was developed to adjust the percent reduction in porosity according to the value of ambient porosity as follows:

$$\begin{aligned} \text{Porosity} < 5\% \quad y &= 3.2167 - 0.5140 \times P_{hi} \\ \text{Porosity} > 5\% \quad y &= -0.3085 + 10.4069/P_{hb} \quad \text{Where:} \end{aligned}$$

y = normalized percent reduction.

Note that the correction for porosities greater than 5% is significantly smaller than that using the Jones and Owens (1980) transform applied in the GGRB study (Scotia, 1993), whereas the correction for porosities less than 5% is similar.

In the GGRB, the permeability overburden correction assumed an average NOB of 4,650 psi, since it was estimated that NOB was essentially constant below 9,000 feet due to an increasing overpressure gradient with depth. In the Piceance Basin, the bulk of the play areas are interpreted to be normally pressured with NOBs which increase with depth. Consequently, the correction must account for variations in permeability and NOB. Combined overburden and gas slippage permeability corrections were generated from MWX core data which are discussed below.

2. Correction of air permeability for gas slippage. The Klinkenberg correction is large for tight gas sands. This correction increases with decreasing permeability and varies depending upon the gas used in the permeability measurement (usually air which is mainly nitrogen) and also the mean flowing pressure. The following expression and associated exponents were used to correct ambient air permeabilities for the effects of gas slippage and overburden:

$$k_{airNOB} = B k_{airAMB}^m$$

Where:

		1,000 psi	3,000 psi	4,000 psi
> 1md	B	.70	.65	.60
	m	1.0245	1.0402	1.0571
< 1md	B	.70	.65	.60
	m	1.4048	1.6297	1.7533

The correction transforms used in the GGRB report are less severe than the above expression.

3. Correction to absolute liquid permeability. The application of the above corrections yields a NOB corrected dry Klinkenberg permeability which is often higher than a measured absolute liquid permeability. This is because the correction for gas slippage does not account for possible rock fluid interaction and alteration of pore geometry during the drying process (e.g., collapse of fibrous illite clay in high temperature ovens). A correction was developed to convert dry Klinkenberg to absolute liquid permeabilities based upon work by Jones and Owens (1980) as summarized below and detailed in Appendix B of the GGRB report (Scotia, 1993).

$$k_w = k_{\infty}^{1.32} \text{ for } k < 1 \text{ md @ NOB, Where:}$$

$$k_w = \text{Absolute liquid permeability, md}$$

$$k_{\infty} = \text{Dry Klinkenberg permeability @ NOB}$$

4. Correction to effective gas permeability. Jones and Owens (1980) determined from their tight gas sand data set that NOB corrected absolute liquid permeabilities approximate effective gas permeabilities measured at irreducible water saturation. Consequently, no further corrections were applied.

Correlation of Core, Log and Test Permeabilities

Based upon data collected in this study, considerable difficulty was found in correlating permeabilities derived from differing sources. Some of this difficulty is related to the way in which each parameter was measured and the effective volume of the reservoir that the measurement represents.

As noted, core and log correlations can be developed which are valid in localized areas but may provide poor correlations in other areas due to various nonquantifiable factors that necessitate a differing empirical relationship. Well test-derived permeabilities are representative of a much larger reservoir volume than those derived from log and core data and thus take into account a greater degree of heterogeneity. Suffice to state that due to the generally variable nature of tight reservoirs, it is a rarity to have test-derived and core/log-derived permeabilities match with any high degree of consistency.

Reservoir Pressure and Temperature

Volumetric GIP estimates require a knowledge of reservoir temperature and pressure in order to determine FVFs. Therefore, it was necessary to develop pressure and temperature relationships versus depth for the basin. Three types of data were employed for the calculation of a temperature gradient. DST maximum BHT data from the WHCS database, log maximum BHT data from the WHCS database, and log BHT data from logs collected for analysis. A temperature versus depth relationship was developed for the DST data first and then compared to BHT as reported on the logs as a reality check. After close inspection of the data, it was determined that a single temperature gradient could not be used for the entire basin. As such, the data was broken up into two subsets based on geographical location using the Green River as the divider. The temperature gradient to the east of the Green River was determined to be $50 + 0.02 \times \text{depth}$ (Figure 13). While the gradient to the west of the Green River was determined to be $90 + 0.011 \times \text{depth}$ (Figure 14). These gradients represent the upper limit of temperatures recorded in the basin.

Pressure data was available from two sources: DST data obtained from the WHCS database, and IP shut-in wellhead pressures from the NPS database. Wellhead pressures were converted to pressure at the depth of the top-most perforation using:

$$P_{wf} = P_{wh} e^S$$

$$S = Gd/53.33 \bar{T} \bar{Z}$$

Where:

G = Gas gravity (air = 1)
d = Depth, feet
 $\bar{T}$ = Temperature at well mid-point depth °R

Field average gas gravity and impurity mole fractions as provided in the RMGA were used to compute Z factors. The average Z factor ($\bar{Z}$) was calculated at $\bar{T}$ and the wellhead pressure, P_{wh} . As a check on the approximate solution for P_{wf} , the eight highest values were checked by calculating the static wellbore gradients. The approximation was found to slightly underestimate the pressure by no more than 10 psi. Two pressure gradients were determined based on the data available the first equally valid in two areas; in the north of the basin underneath the Altamont Bluebell Field and in the east part of the Natural Buttes Field. Figure 15 indicates the location of the overpressured areas. It should be noted that although there are no pressure data points in the Mesaverde at Altamont Bluebell, this area is presumed to be overpressured by Fouch (1992) and Spencer (1987). All other areas are considered to be normally pressured.

The average pressure gradient for the overpressured points, defined as any pressure value for which $P/d > 0.5$ psi/foot, were used to determine the overpressure gradient. A regression fit of this data yielded the relationship: $P_{wf} = 0.623 d - 413$. The overpressured data points and the regression fit are plotted on Figure 16.

As a result of the pressure analysis, the following points are noted:

1. There is evidence of overpressuring in the Mesaverde and Wasatch non-associated gas plays.
2. An overpressure gradient of 0.623 psi/foot is equally valid for both plays.
3. Overpressuring extends above 5,000 feet, perhaps as high as 3,000 feet.

In cases where play boundaries span the Green River or include both overpressured and normally pressured areas, temperature and pressure gradients were calculated using area-weighted averages.

FIGURE 13

FIGURE 14

Figure: 15

FIGURE 16

Natural Fracturing

Summary of Fracturing in the Uinta Basin

Major structural features are mostly absent in the interior of the Uinta Basin. Those that do exist include the Uinta Basin axis adjacent to the north edge of the basin, the Duchesne fault zone in central Uinta, and the Jacks Canyon and Mill Creek anticlines, and the reactivated Garmesa fault zone and associated Uncompahgre Uplift in south Uinta. Fracture systems associated with these and major structural features bordering the basin (Uinta Mountains, Douglas Creek Arch, and Charleston Nebo thrust) have been identified. These include the northwest trending Cowboy-Bonanza, Rainbow, Willow Creek, and Ouray systems which are concentrated in the central and eastern portion of the basin, and the north-northwest trending Fort Duchesne and Pariette systems, and the east-west trending Duchesne fracture zone (Figure 17). North and north-northwest trending fractures also exist across the Wasatch plateau and western flank of the basin in Greater Natural Buttes and surrounding areas. The best defined regional fracture systems include the east-west trending Duchesne fracture zone which parallels the Uinta Mountains, and the Gilsonite veins of the Greater Natural Buttes area which strike west-northwest, roughly parallel to the Uncompahgre Uplift.

More locally the orientation and density of fractures is controlled by folds as seen at Bluebell, Pleasant Valley, Peters Point, and Natural Buttes. Here fractures parallel the axis of structures (Type II fold related fractures of Stearns and Freidman, 1972) and are concentrated along mild surface or sub-surface anticlines and structural noses (Clem, 1985). Gilsonite dikes occur throughout much of the Greater Natural Buttes Field area. Gilsonite is a predominantly aromatic asphaltite with a fusing point above 230° F. The gilsonite dike dominant strike orientation is north 40-70° west with a vertical to sub-vertical dip (Verbeek and Grout, 1992). Dike dimensions range between less than one mile to 14 miles in length, less than one inch to 18 feet in width, and from a few feet to at least 3,000 feet in depth (Verbeek and Grout, 1992). The gilsonite source beds are the lacustrine oil shales of the upper part of the Green River formation (Hunt, 1979). Verbeek and Grout (1992) proposed that "hydraulic extension fractures" were formed within overpressured source beds during the initial phases of regional northeast-southwest post-laramide tectonic extension. The fractures served as conduits for formation water movement and were subsequently infilled with viscous gilsonite. Dikes extend between the upper most Wasatch and lower part of the Duchesne River formation and are rare below the Green River source beds, so their impact on Wasatch production may be minimal. Gilsonite fracture strikes are similar but not identical to Verbeek and Grout's (1992) F2 fracture set. The gilsonite dikes are

considerably longer and their abutting and cross-cutting relationships are different and probably pre-date the regional F2 fractures.

The same five sets of near vertical joints identified by Verbeek and Grout (1992) in the Piceance Basin (Piceance System) are common to the eastern Uinta Basin and are summarized below:

SET	STRIKE RANGE	ABUNDANCE
F1 (Oldest)	N 15 to 30 W	Sparse
F2	N 55 to 85 W	Very Abundant
F3	N 60 to 80 E	Moderate
F4	N 15 to 40 E	Very Abundant
F5 (Youngest)	N 65 to 85 W	Sparse

Verbeek and Grout (1992) date the three oldest fracture sets at between 43 and 10 mya and the two youngest sets beginning about 10 mya. Fractures illustrated in Figure 17 around Greater Natural Buttes correspond to the F2 set. They are related to the regional tectonic extensional history of the northeastern margin of the Colorado plateau (Verbeek and Grout, 1992). F1 and F5 sets are rare in Uinta and F2 fractures are dominant at most localities. Bed parallel joints also exist which are related to uplift, erosion and decompression at around F4 time.

Few faults have been identified at Greater Natural Buttes, primarily because of the discontinuous nature of the Mesaverde, Wasatch and parts of the Green River formation (Osmond, 1992). Only where they cut the lower Green River where continuous lacustrine carbonate beds can be correlated between wells are faults recognized. Generally the faults formed during deposition of the Green River formation, they strike northwest and do not reach the surface. The Duchesne fault zone, west of Greater Natural Buttes, extends some 50 miles and cuts the Uinta and Eocene-Oligocene Duchesne formation.

Figure 17 presents a compilation of regional fracture measurements and fault and structure systems for the Late Cretaceous-Tertiary section in the Uinta Basin. This map attempts to illustrate those areas where fold and fault related fracturing should prevail and enhance the connectivity of regional orthogonal fractures. In the Piceance Basin, Tyler (1995) predicts that fracturing in the northern half of the basin may be more open than in the south since the dominant system parallels the present-day west-northwest regional maximum horizontal stress pattern. This may also be the case for the Uinta Basin.

Figure: 17

Modified From Verbeek & Grout(1992), Osmond(1992), Chidsey and Laine(1992)

LEGEND

	ANTICLINE		FRACTURE ZONE
	SYNCLINE		FAULT
	GILSONITE VEINS		FRACTURE ORIENTATION
			HIGH ANGLE NORMAL FAULT

U.S. Department of Energy

Uinta Basin

REGIONAL FRACTURES, FOLDS, & FAULTS

Prepared by The Scotia Group, Inc.

Drilling

The tight gas reservoirs of the Uinta Basin are known to be sensitive to drilling and completion fluids. Such sensitivity is related to one or more of the following contributing factors:

1. **Plugging:** Because the pore structure is characterized by adjoinment involving thin ribbon-like micro-fractures as opposed to discrete pore throats, entry of particulate matter can cause plugging and isolation of the wellbore from the main body of the formation.
2. **Fluid Invasion:** Most tight gas reservoirs are characterized by a greater or lesser amount of authigenic clay mineralization, some of which may be sensitive to fluids invading the formation as mud filtrate. This can cause swelling or dislodgment and migration to block permeable channels during subsequent production.
3. **Drilling Induced Fracturing:** Drilling induced fracturing has been noted and acts to impart localized near-wellbore areas of weakness that may cause increased tortuosity during subsequent frac treatment, thus reducing the effectiveness of such fracs.

Drilling cost data was collected from operators responsible for drilling in excess of 80% of the gas wells in the basin. An average dry hole drilling cost was calculated at \$29.00/foot, while drilling and completion costs were estimated at \$74.00/foot.

Casing programs were evaluated over time for the Natural Buttes Field in both the Mesaverde group and Wasatch formation. The Natural Buttes Field was chosen because of the large number of wellbores available for analysis. Wells were divided into six groups based on first productive year and productive formation summarized in Table 9.

TABLE 9
COMPLETION AND WELLBORE SUMMARY

	TIME PERIOD	NUMBER OF WELLS *	
		WASATCH	MESAVERDE
1976-1984	1	208	18
1985-1989	2	145	12
1990-1994	3	59	7

* Number of wells refers to number of wells with full casing information listed in the WHCS database

Casing programs consist of two types, those with two strings and those with three. Both types are present in each of the time periods in both formations. Three casing strings are more often used in deeper wells and become less prevalent as the average TD decreases. For a typical Wasatch completion in the Natural Buttes Field, a three string casing program would consist of setting a surface 13 $\frac{3}{8}$ " string to an average of 194 feet, setting an intermediate 8 $\frac{5}{8}$ " string to 2,400 feet, then setting 4 $\frac{1}{2}$ " casing to 7,000 feet. A 2 $\frac{3}{8}$ " tubing string is run to about 6,250 feet. Average TD of a three string well is 7,270 feet.

Average depth for a two string casing program is almost 700 feet shallower than that of a three string. An average two string casing program consists of a surface string set to 303 feet, followed by a 5 $\frac{1}{2}$ " or 4 $\frac{1}{2}$ " casing set to 6,843 feet. On average 2 $\frac{3}{8}$ " tubing is set to 5,869 feet. Table 10 lists drilling statistics for both two and three string programs over the three time periods for Wasatch completions.

TABLE 10
WASATCH DRILLING STATISTICS

PROGRAM	TIME PERIOD	CASING PROGRAM	# OF WELLS	AVG TD	% OF TOTAL IN TIME PERIOD	AVG EUR
3 String	1	13 $\frac{3}{8}$ " to 194 feet 8 $\frac{5}{8}$ " to 2,440 feet 4 $\frac{1}{2}$ " to 7,000 feet	50	7,082	24	587
	2	13 $\frac{3}{8}$ " to 155 feet 8 $\frac{5}{8}$ " to 2,149 feet 4 $\frac{1}{2}$ " to 7,700 feet	16	7,700	11.3	588
	3	13 $\frac{3}{8}$ " to 60 feet 8 $\frac{5}{8}$ " to 465 feet 5 $\frac{1}{2}$ " to 7,166 feet	2	7,269	1.6	934
2 String	1	9 $\frac{5}{8}$ " to 303 feet 5 $\frac{1}{2}$ " to 6,643 feet	158	6,873	76	819
	2	9 $\frac{5}{8}$ " to 240 feet 5 $\frac{1}{2}$ " to 6,664 feet	125	6,664	88.7	544
	3	8 $\frac{5}{8}$ " to 281 feet 5 $\frac{1}{2}$ " to 6,440 feet	57	6,440	98.4	651

Wasatch average total depths have generally decreased over time. This is evident by the average TD for two string programs dropping from 6,873 feet to 6,480 feet and by the drop in the percentage of three casing string wells being drilled, from 24% to 1.6%. Most of the more recent wells have been drilled in the more easterly areas of the field where depth to top of Wasatch and Mesaverde is shallower.

Table 11 lists drilling statistics for both two and three string casing programs over the three time periods for Mesaverde completions.

**TABLE 11
MESAVERDE DRILLING STATISTICS**

PROGRAM	TIME PERIOD	CASING PROGRAM	# OF WELLS	AVG TD	% OF TOTAL IN TIME PERIOD	AVG EUR
3 String	1	13 $\frac{3}{8}$ " to 200 feet 8 $\frac{5}{8}$ " to 2,305 feet 5 $\frac{1}{2}$ " to 7,950 feet	12	8,031	67	477
	2	13 $\frac{3}{8}$ " to 118 feet 8 $\frac{5}{8}$ " to 2,274 feet 5 $\frac{1}{2}$ " to 9,028 feet	7	9,028	58	547
	3	13 $\frac{3}{8}$ " to 224 feet 8 $\frac{5}{8}$ " to 2,553 feet 4 $\frac{1}{2}$ " to 9,936 feet	2	9,936	29	145
2 String	1	9 $\frac{5}{8}$ " to 1,283 feet 4 $\frac{1}{2}$ " to 7,698 feet	6	7,711	33	702
	2	9 $\frac{5}{8}$ " to 1,289 feet 4 $\frac{1}{2}$ " to 8,016 feet	5	8,016	42	623
	3	9 $\frac{5}{8}$ " to 709 feet 5 $\frac{1}{2}$ " to 8,360 feet	5	8,396	71	683

Immediately noticeable from the table is the trend away from three casing string programs toward two casing programs. This again is probably attributable to well location.

Completions

The Natural Buttes Field dominates both the Wasatch and Mesaverde plays in terms of number of wells and EURs. Wasatch completions in the Natural Buttes Field account for 82% of all the completions in all the plays in the basin, as such, enough information was available to generate relevant completion statistics and quantify how they have changed over time.

The Wasatch Natural Buttes completions were separated into three categories based on date of first production. A complete set of data was required for each completion before it was included in one of the three categories. This information included EUR, TD, upper and lower perforation interval, and initial production date. The three time periods are considered from 1976-1984, 1985-1989 and 1990-1994, referred to as time periods one, two and three. These time periods contained 195, 130 and 68 completion entities respectively. Analysis

indicates that average EURs dropped 193 MMcf or 25% from 767 MMcf to 574 MMcf between time periods one and two. EURs have since rebounded to 88% of the original average.

The average gross completion interval has also dropped by 78 feet since time period one. No correlation can be drawn between gross completion interval and EUR since the average gross completion interval rose 32 feet during time period two resulting in a 193 MMcf drop in average EUR. Average depth to completion mid-point is becoming shallower, but only by 213 feet from an average of 6,000 feet to 5,787 feet.

Wells drilled during time period one tended to be both extension and infill wells. Wells drilled during time period two tended to be more of the infill variety with the exception being toward the northeast area of the field. Almost all wells drilled in time period three are infill wells. Even though the majority of wells were infill, the average EUR rose between time period 2 to time period 3, suggesting that the reservoir pressure at these locations had not been significantly reduced by drainage due to offset well production. This gives rise to optimism that continued infill drilling will yield similar EURs.

Even though the Mesaverde is known to be productive, few wells penetrated the group at Natural Buttes. Less than 6% of wells completed in the Wasatch TD'd in the Mesaverde. However, 70 wells dually completed in the Wasatch and Mesaverde or solely in the Mesaverde formation. Table 12 lists all relevant completion statistics for wells completed in the Wasatch formation in the Natural Buttes Field.

**TABLE 12
WASATCH COMPLETION STATISTICS**

YEAR	NUMBER	AVG EUR MMcf	AVG COMPLETION INTERVAL FT	AVG COMPLETION DEPTH FT	% DRILLED INTO MESAVERDE
1978-1984	195	767	928	6,000	7
1985-1989	130	574	960	5,915	3
1990-1994	68	679	850	5,787	7

Mesaverde completions in the Natural Buttes Field were also broken down into the three time periods discussed previously. A Mesaverde completion can be one of two types: 1) completed solely in the Mesaverde or 2) a commingled Wasatch and Mesaverde completion.

Over time, average EURs have dropped for all Mesaverde completions from 649 MMcf in time period one to 246 MMcf in time period three. It should be noted that in time period

one the average EUR for a well completed in both the Wasatch and Mesaverde was 1,011 MMcf. This dropped 61% by time period two to 392 MMcf. Mesaverde completions have also dwindled over time from 30 in time period one to only six in time period three.

EURs for wells completed across both the Wasatch and Mesaverde formations during time period one exceeded the EURs of Wasatch-only completions during the same time period by an average of 32%. Therefore, the possibility exists to significantly increase EURs by deepening new wells into the Mesaverde and completing both formations.

The above statistics are relevant only to the Natural Buttes Field. Typically the Natural Buttes Field is deeper and is more productive in terms of EUR/well than other Wasatch producing fields.

Hydraulic Fracturing

The successful completion of gas wells in Wasatch and Mesaverde pay zones is very dependent on hydraulic fracturing to stimulate productive capacity. This stimulation method has been employed in the basin for more than four decades. During that time, the technology of fracturing has evolved and expanded greatly. The evolution can be ascertained in part by reviewing the treatment data contained in the WHCS database.

Figure 18 illustrates how the usage of fracturing fluids has evolved during this four decade period. The WHCS database shows that prior to 1970, 50 wells (11.5% of the total treatments) were treated. The predominant fracturing fluids were oil (SOFR), followed closely by water (SWFR), together accounting for four out of five jobs. Acid (SAFR) was used in one of five jobs during this period. In the 1970s emulsion fracturing fluids (SEFR) were used in almost one half of the 132 reported jobs (30.3% of all treatments) and gelled fracturing fluids (SGFR) were introduced and used in one of four treatments. Water or acid was used for the remainder of the 1970s' jobs. A total of 239 fracture treatments or almost 55% of the total to date were performed in the 1980s. The most commonly reported fluid was water with gelled and foamed fluids (SFFR) in second and third place. No evidence of gas being used as a fracturing fluid (SGAF) has been reported for the Uinta Basin. Activity in the current decade has diminished to 15 jobs (< 5% of the total) and gelled and water fluids have been used with equal frequency.

Figure 19 shows how the treatment size in terms of pounds of proppant has increased with time. The trend toward larger sand volume should yield larger fractures with larger surface area in contact with the reservoir rock, with the expectation of improving initial potential and increasing EURs with time.

FIGURE 18

FIGURE 19

Modern gel based fracturing fluids use improved polymers and delayed cross-linkers to obtain improved rheological properties. By delaying the cross-linking action, pumping friction is reduced in the well tubulars while the more viscous fluid propagates a wider fracture and more efficiently transports the proppant. Combined with the advent of fracture simulators for treatment design, the expected result should be higher productive capacity and larger reserves (EUR).

Figure 20 shows how the changes in fracturing fluids and proppant volumes have impacted the initial potentials (IP) as reported in the WHCS. At first inspection this graph suggests that the improvements in fracturing fluid and treatment procedures have all been for nought, as the IP trend with time, if anything, is downward. Since the majority of these wells are in the Natural Buttes Field, it is possible that depletion by offset producers is in some part responsible for this trend. While this trend remains disturbing, it is also known that tight gas wells commonly show prolonged post-frac clean up periods characterized by improving productivity. The greater volumes of fracture fluids required to transport the larger proppant volumes act to prolong the clean up period and undoubtedly more severely depress the post-frac IP. It remains unclear if these two effects account for the downward trend of IP with time.

FIGURE 20

FIGURE 21

If modern fracturing technology and larger proppant volumes are in fact improving the recovery of gas from the Wasatch Mesaverde, it should be evident in the EURs of the treated wells. As Figure 21 clearly shows, this is indeed the case. Per well recoveries are shown to have increased from 475 MMcf in the 1960s to 656 MMcf in the 1990s. Improvements in fracturing technology and practices have occurred but are apparently offset by drainage effects seen in the most recent wells as the Natural Buttes Field is infill drilled to a 40 acre spacing. This statement may apply only in selected parts of the field, since drainage area calculations yield only ten to 20 acre effective drainage in some situations.

The relationship of fracture treatment variables to EUR has been investigated and is presented in the topical report: *Tight Gas Sand Reservoir Response to Stimulation by Hydraulic Fracturing - Case Studies in the Uinta and Piceance Basins* (Scotia, 1995).

The studies used comprehensive treatment data supplied by three of the prominent operators in the Uinta Basin: Coastal Oil and Gas (Coastal), CNG Producing Company (CNG), and Enron Oil and Gas (Enron). All of the Coastal and CNG data was for wells in the Natural Buttes Field. The treatment philosophy of the two operators is fundamentally different in that CNG selectively treats the gross pay interval with two or more separate fracs, whereas Coastal treats similar intervals in a single treatment. Comparing the Coastal and the CNG wells on the basis of EURs presented in this report suggests that there is no advantage to using multiple fracture treatments.

OPERATOR	PRACTICES	MEDIAN EUR	NUMBER OF WELLS
Coastal	Single Fracs	632	95
CNG	Multiple Fracs	378	62

Production Performance

Analysis of production performance data provided several key elements for this study:

1. All wells identified as being productive from the tight section were projected utilizing rate versus time and rate versus cumulative techniques to derive an EUR. The economic limit was calculated assuming operating costs of \$1,000/month as being average for the basin, an assumed 18.75% royalty, 7.15% combined severance and ad valorem tax, and a \$2.00/Mcf wellhead gas price. The use of this gas price was a study requirement by the DOE. These EURs provide the base measure of ultimate well performance.
2. Initial Productivity and Decline Characteristics: These items governed the rate of gas recovery and provided the profile for recovery. It should be noted that while some wells exhibit the classic low permeability gas signature of a transient flush production (rapidly decreases from initial rates and then gradually stabilizes at a low rate of decline), many more tight gas completions exhibited erratic production behavior more connected with externally imposed producing and market conditions. For example, seasonal curtailment is noted at one time or another in most wells across the basin. In addition, many wells are produced in cyclic fashion, presumably in response to high local line pressures and low well productivity. Some previous researchers have discussed the initial linear flow period in these tight zones due to the massive hydraulic fracs placed on these wells. However, due to the curtailed nature of the production discussed above, no improvement was achieved through the use of linear flow analysis. Historic production from most wells, even the best wells in the basin, could be fit with a hyperbolic curve with an exponent of approximately 0.5. It also should be noted that even with curtailment and various shut-in periods, most wells exhibited fairly steady decline rates after the initial transient period and are thus fairly predictable in terms of production performance.
3. Transient Production Behavior: Many wells exhibited a transient phase of production that could last for several years. Analysis of this phase utilizing Fetkovich type curves in conjunction with data from other sources provided valuable information on permeability and drainage area.

Fetkovich analysis was performed on wells containing enough backup petrophysical information, i.e., log analysis estimates of ϕ , S_w , and h , as well as enough production data to allow for a meaningful fit with the type curves. This analysis depends upon various factors such as: estimates of initial and final bottomhole pressures, bottomhole temperature, gas gravity, and wellbore radius, along with the items mentioned above. For this reason, only a sampling of wells was identified as having enough information to produce meaningful results.

Although this procedure is very sensitive to subtle changes in the fit of production to the type curves, the final completed drainage radius value was checked against the drainage radius calculated using the same petrophysical parameters and a recovery factor ranging from 81% to 87% of GIP depending on the play. In general, drainage radius calculations from the Fetkovich analysis were slightly lower, but did serve as a check in terms of order of magnitude for the constant recovery factor model. In addition, since pressure data was extremely sparse, it was not possible to perform any reserves analyses based on P/Z data.

4. A break down of typical performance profiles for tight wells by play is summarized in Table 13:

TABLE 13
TYPICAL PRODUCTION PERFORMANCE PARAMETERS BY PLAY

	MESAVERDE	WASATCH
Average Initial Rate (Mcf/d)	237	741
High Initial Rate (Mcf/d)	2,001	3,563
Average Initial Decline	60%	58%

5. Average play production profile curves were created for wells with production history of at least ten years and a minimum EUR of 1 Bcf, in an attempt to use Fetkovich type curves to determine average drainage areas for the superior producers in each play. The production profile curves were created using the following methodology:
 - a. All wells with a production start date prior to February 1976 were eliminated. January 1976 is the first date of monthly reported producing volumes. All wells with this start date were assumed to have commenced production at some unknown earlier date and, as such, were eliminated.
 - b. Wells were divided into subsets based upon producing play.

- c. Production from all remaining wells was normalized to time zero.
- d. Total production and number of producing wells were tabulated for each month for each play.
- e. EURs for all wells used to create the production profile were averaged to generate an average EUR for the typical superior well. The EURs were used to volumetrically back into a drainage area. In the Wasatch play, drainage areas calculated using Fetkovich types curves and volumetrics were consistent.
- f. Average pay in feet was then calculated for each play by overlaying the wells on the pay isopach and averaging the pay thicknesses.
- g. Pressures and temperatures were calculated for each play based on average perforation depth of all wells used to create the average production profile.
- h. Average porosity and water saturation values were derived from log analysis in the net pay sections.
- I. Finally, Fetkovich type curve analysis was used to determine drainage areas for a typical large EUR well in each play. This was done using a hyperbolic exponent of 0.5.

The average drainage area for a superior Wasatch well in the Natural Buttes Field was calculated to be 97 acres, while well spacing is 40 acres. This indicates that the drop in average EURs over the last 20 years may be due in part to partial pressure depletion within the flow boundaries of the more recent wells adjacent to wells with large EURs.

There is not enough data available to construct an average Mesaverde type curve. Only three wells have achieved 1 Bcf and only two have begun production since 1976. Each of the remaining wells had periods during their production when they were shut-in, destroying any chance of fitting the transient portion of the decline curve to a type curve.

Economic Considerations

Base economics are the driving force for development of any "technology" play such as the development of tight gas reserves. It is fair to say that the Uinta Basin has suffered over the years from gas prices and market takes that are below national averages.

The base premise for this study is to examine reserves development potential based upon an assumed gas price of \$2.00/Mcf.

Base economic considerations can be broken down into the following elements:

1. **Capital Costs:** Consist of the cost to drill, complete and equip a gas well that is inclusive of front end costs such as leasehold, seismic and geological costs.
2. **Operating Expenses:** These consist of the monthly charges for direct and indirect expenses to operate the gas well.
3. **Local Taxes:** These consist of local state severance and ad valorem taxes.
4. **Lease Royalty Expense:** This represents the royalty burden that must be borne by the gas well and will be variable depending upon whether the leases represent freehold, state or federal land.
5. **Production Profile:** This represents the rate of gas production over time and hence the likely distribution of derived revenues assuming a \$2.00/Mcf constant gas price as required by the study specification.

A combination of the above parameters results in a projected cash flow profile for a given well. Several factors are worthy of note:

1. **Wells Exhibiting a Typical Tight Gas Signature:** That is, exhibiting an initial rate which declines rapidly in a hyperbolic fashion to stabilize at a low sustained level, the shape of the hyperbolic decline is extremely important. In situations where the rates drop to a break-even level with relative rapidity, the bulk of the cash flow from the well is derived early in its life.
2. **Once the production has stabilized or the well has "turned the corner,"** base economics of further production depend upon the production rate and price versus operating cost levels. Many tight gas wells are sensitive to small fluctuations in price and operating cost to determine their profitability.
3. **A wide range in well performance is noted both on a regional basis and down to the well level within an individual field.** This is apparently the norm for tight gas wells with the EURs being lognormally distributed at most levels of aggregation.

Due to the fact that tight wells must be frac'd in order to determine productivity characteristics, a significant proportion of completions do not ultimately pay out. That is, while such wells produce sufficient gas volumes to operate profitably by covering operating costs, the payout of drilling and completion costs is never achieved.

RESERVES EVALUATION BY PLAY

In examining resources and estimating what proportion of those resources is technically and economically recoverable and hence available for conversion to reserves, it is useful to diagrammatically express such concepts for the purposes of clarity. This concept was first proposed by the USGS as the McKelvey Box (Figure 22).

The McKelvey Box is an extremely useful tool for illustrating the relationships between reserves and resources. While this concept is embraced by industry, formal linkage of McKelvey's "measured," "indicated," and "inferred" categories with standard industry usage of proved, probable and possible has not occurred due to base concept and purpose differences.

The McKelvey Box was originally developed in 1972 when McKelvey was a director of the USGS. The box represents the total volume of unproduced mineral resources and classifies such volumes with reference to a horizontal axis representing the degree of geologic and engineering certainty, and a vertical axis representing the range of economic feasibility of recovery of such minerals.

FIGURE 22

THE MCKELVEY BOX

The economic and geologic axes each have two principal divisions. On the geologic axis, the logical division is between mineral deposits that have been discovered and those which are postulated with varying degrees of certainty but are still undiscovered. This line constantly moves to the right as more resources are discovered and converted to reserves. Likewise, as reserves are produced, they exit the upper left hand corner of the box to become cumulative production. On the economic axis, the division is between those volumes for which technical characteristics and the existing combination of costs and prices make them profitable to recover, and those that are not. This line moves down over time as technological advances make an increasing fraction of the resource base economically extractable. Cost and price changes will also cause vertical movements of this line.

The upper left hand sector of the McKelvey Box contains reserves. On the horizontal or geologic axis, these are the volumes of oil and gas about which there is the greatest confidence in their existence and characteristics. They have been discovered and characterized by information obtained through drilling. On the vertical or economic axis, reserves are restricted only to those volumes of discovered minerals for which there is the highest certainty about the feasibility of economic recovery.

The remainder of the McKelvey Box is filled by resources. These are minerals which remain to be discovered or have been discovered but for which economic recovery under present conditions is judged uncertain.

The normal subdivision of reserves, as represented by the standard SPE definitions, resides in the upper left hand corner of the McKelvey Box. To qualify as reserves, such volumes must pass an economic producibility test, a test of existence and a further test of level of certainty of existence. Where such reserves are thought to be reasonably certain, they are classified in the proved category. Reserves which are identified but do not pass the reasonable certainty test are classified in the unproved category with subdivisions noted as probable and possible.

For the purposes of expressing the results of this project, we have chosen to utilize the McKelvey Box concept in a modified form. This modification calibrates both X and Y axes in terms of the fundamental controlling technological and economic parameters.

Considering firstly the X or technology axis, this has been calibrated as a function of average reservoir permeability on a logarithmic scale. In addition, the axis has been reversed in comparison to the original McKelvey Box whereby permeability increases from left to right. The technology axis is subdivided based upon permeability ranges. The primary subdivision is between conventional reservoirs having permeabilities of greater than 0.1 md and unconventional reservoirs having permeabilities of less than 0.1 md. The second subdivision of the horizontal axis is based upon the current state of massive hydraulic fracturing

technology. This technology is necessary to produce unconventional gas reservoirs at commercial rates and the current range of effective technology application is in the range of 0.001 to 0.1 md Holditch (1992). The lower limit of this range at $1 \mu\text{d}$, essentially separates the technology axis into *technically nonviable* resources versus *technically viable* resources, a portion of which becomes recoverable reserves based on the appropriate recovery factor. As improvements in fracturing technology are made, the boundary between *viable* and *nonviable* will move to the left and resources will move to the right.

The vertical, or economic axis, is calibrated in units of drill depth and hence drilling cost. While the economics will be dependent upon a variety of factors including levels of royalties, taxes, gas prices and success ratio as well as cost to drill and complete, including frac cost, the primary consideration is the interplay of potential reserves volumes versus base drilling and completion costs. Because drilling and completion costs increase with depth, and potential reserves volumes per well tend to deteriorate with depth because of deteriorating porosity, the interplay of these two factors generates an *economic basement* that can be expressed as a function of drill depth, hence the choice of this parameter for the vertical axis. For a given play, the identified resource will occupy a given depth range between the top and base of play with *economic basement* lying above, below or within that depth window depending upon the interplay of reserves and economics.

As economic conditions change, the *economic basement* line will move vertically. Increasing gas prices, decreasing royalties, taxes or increasing incentives or decreasing drilling cost will move this line down and resources will move up into the *established* category. The reverse also applies in that as costs increase or gas prices drop, the *economic basement* will move up and resources within the *established* category will move to nonestablished.

Figure 23 illustrates this subdivision. Only those resources in the upper right hand area being available as candidates for conversion into reserves by virtue of being potentially technically and economically recoverable. Thus only the fraction of that resource which is considered recoverable represents reserves. For resources below *economic basement*, reserves may still exist but their character will be higher risk and more costly, and thus they will represent a smaller fraction of the resource.

By breaking down the resource estimate into the four basic components based upon technical and economic feasibility of recovery, visualization of what components of that resource will be subject to changes in status in the future can be made. Such status changes will be the result of technological advances and economics by virtue of changes in prices, costs and the imposition of incentives. The diagram also allows the challenge that industry faces in attempting to exploit this resource to be examined in comparing one play to the next. This becomes obvious when comparing plays where the resource is located principally at depth versus those where a greater proportion is in the shallower depth ranges. For the deep

resource to become economic, major changes in the cost and price environment must occur as opposed to the shallower resource. In addition, the relative proportion of the total evaluated resources occurring within each permeability range allows the benefits of technology improvements to be evaluated in terms of how much of the resource is available for the conversion to reserves by application of such technology.

The USGS subdivided the Uinta Basin into six plays for the purpose of conducting their reserves estimate. For our purposes we subdivided the Uinta Basin into two plays based on formation, Wasatch and Mesaverde. These plays were further subdivided into subplay based on thermal maturity and depth. Refer to Table 5 for play name comparisons.

MESAVERDE PLAY

Description

The Mesaverde Play is the deepest stratigraphic unit considered by the USGS and includes all strata lying between the top of the Mancos Shale and the base of the Wasatch formation. The Mesaverde is divided into three distinct subplays; gas-saturated deep synclinal $> 15,000$ feet, gas-saturated $R_o > 1.1$ & $< 15,000$ feet, and gas-water transitional R_o 0.7-1.1. It is important to note that the play boundaries for the Mesaverde subplays correspond approximately to the R_o 1.1 and 0.7 lines as they intersect the base of the Mesaverde group.

Figure 24 displays the three USGS play boundaries along with all Mesaverde penetrations. Gas wells in this figure include Mesaverde completions and completions in deeper formations such as the Mancos and Dakota. As is clear from the figure, there is no well control in the western or extreme southern edges of the basin. Well control is also sparse northwest of the Natural Buttes Field toward the Altamont/Blue Bell area. Figure 25 displays Scotia's play boundaries which differ from those of the USGS along the boundary between the gas-saturated and deep synclinal gas-saturated subplays, and the next eastern updip limit of the gas-water transitional subplay.

Figure 25 indicates the majority of Mesaverde production originates from the Greater Natural Buttes area and also displays those areas designated tight by the FERC. Note the number of dry holes in the south and to the west of the Green River. The producing wells in these areas are also uneconomic based on small EURs at Peters Point the only Mesaverde producing well recovered only 17 MMcf and hence the entire rock volume in these areas has been labeled *nondemonstrated*. This includes all the gas-saturated deep synclinal $> 15,000$ feet play, most of the gas-saturated $R_o > 1.1$ & $< 15,000$ feet play west of the Green River, and the gas-water transitional play west of the Green River and south of Township 11S. Figure 26 shows the *demonstrated* portion of the Mesaverde play along with a graphical representation of EURs for all Mesaverde gas completions.

Fields producing from the Mesaverde are summarized in Table 14. This table also demonstrates the dominance of the Natural Buttes Field in terms of number of wells drilled and EUR/well. The Natural Buttes Field accounts for 53% of the completions and 84% of the EURs with an average EUR of 555 MMcf/well. Average EURs for other wells in the Mesaverde are just 121 MMcf/well. Figure 27, a composite production profile for the Mesaverde Play, shows about 65 wells currently producing at an average rate of 90 Mcfd/well.

TABLE 14
MESAVERDE PLAY FIELD LIST

FIELD NAME	AVG DEPTH (Feet)	CUM MMcf	EUR MMcf	NUMBER OF WELLS	AVG EUR MMcf/WELL
Agency Draw	5,841	5	5	2	3
Bitter Creek	7,337	382	558	3	186
Devils Playground	7,048	42	42	2	21
Hill Creek	5,715	152	152	1	152
Love		111	111	1	111
Main Canyon	4,378	731	731	1	731
Natural Buttes	7,099	32,120	38,871	70	555
Oil Springs	3,325	17	17	1	17
Peters Point		17	17	1	17
Pine Springs		2	2	1	2
Red Wash Greater	6,313	2,212	2,212	3	737
Rock House	5,100	1,478	1,478	6	246
Undesignated	4,352	623	1,719	32	54
Unnamed 15-9S24E		4	4	1	4
Unnamed 2-11S19E	9,102	25	42	1	15
Unnamed 22-10S17E	10,197	49	49	1	49
Unnamed 23-13S20E		2	3	1	3
Unnamed 23-13S20E	5,574	6	6	1	6
Uteland Butte	9,045	226	244	2	122
TOTAL		38,204	46,263	131	353

Drilling statistics are again dominated by the Greater Natural Buttes area. Historically 52% of all Mesaverde wells have been dry. During the 1950s the dry hole frequency was 100% and prior to 1970 it was still over 90%. In the 1990s the dry hole frequency dropped to 12%. In determining a dry hole factor for the Mesaverde only, recent wells drilled in the *demonstrated* area were considered. A dry hole factor of 12% was used in reserves modeling. Examination of the distribution of EURs indicates approximately 13% of the wells are commercially *viable*, leading to a commercial success ratio of 11.4% (Figure 28). The

commerciality percentage calculation is based on the proportion of EURs having a PV10 exceeding the cost to drill and complete a well relative to the average producing depth (6,810 feet) for the play.

Stratigraphy and Rock Properties

All strata of the Campanian Mesaverde group, lying beneath the Paleocene Wasatch, Colton and North Horn formations and Flagstaff member of the Green River formation, whose base is marked by the Laramide unconformity, and lying above the Santonian/Campanian Mancos proper (Blue Gate member), were considered for inclusion in the Mesaverde Play. Formations and members within this group include generally from youngest to oldest: Tuscher, Farrer and Price River formations, Neslen and Sego formations, Castlegate formation, Black Hawk formation and Star Point sandstone. In the majority of the wells evaluated however, most of these strata are not differentiated and are collectively grouped under "Mesaverde."

These formations and members were deposited as a result of a series of marine transgressions and regressions which occurred across the Uinta Basin area between Early and Late Campanian time. Following a Late Santonian/Early Campanian transgression, Mesaverde sedimentation began with the Star Point sandstone, a marine near shore facies, and later during a subsequent regressive phase by the Black Hawk coastal plain and near shore sediments, which prograded some 25 miles east of the Green River as the seaway retreated to its most easterly position during Mid-Campanian. Paleogeographic reconstructions of the Mesaverde section (Fouch et al, 1992, Franczyk et al, 1992) can be used to provide snapshots of depositional conditions during the Mesaverde (Figure 29). The first time slice illustrates the most regressive phase of sedimentation during the early part of the Late Campanian. Alluvial sedimentation, sourced from the Sevier thrust belt, extended east of the Green River. The Castlegate formation (which has only member status in the neighboring Piceance Basin) is represented by alluvial plain and coastal plain deposits. To the southeast, the Blue Gate member of the Mancos shale was deposited in the open seaway. A localized unconformity in southwest Uinta separates the Castlegate from the underlying Black Hawk formation. The second time slice illustrates the most westerly extent of the middle part of the Late Campanian transgression and shows a widening and northwesterly shift of the zone of coastal plain deposition. The Buck Tongue of the Mancos shale, deposited in the seaway, extends approximately ten miles west of the Green River and covers the eastern half of the basin. To the west lies the Castlegate sandstone. This formation is widespread across the basin based on well control and is present in outcrop across the whole south basin rim where it forms cliffs. It is encountered between 3,000 feet md at the eastern basin edge and almost 12,000 feet md in the west half of the basin and is predicted to exist in the basin deep where well control is poor. Its thickness in the Greater Natural Buttes area ranges from 250 to 300 feet. The third time slice represents the middle to late part of the Late Campanian and illustrates the retreat

of the Mancos Sea beyond the southeast basin limit. Accompanying this retreat was the deposition of the Sego and Neslen regressive sandstones and landward of these the Blue Castle Tongue of the Castlegate sandstone (Fouch, 1983). The fourth time slice represents depositional conditions at the close of the Campanian and displays braid plain deposition of the undifferentiated Tuscher and Farrer formations in eastern Uinta and Price River formation to the west. The Tuscher and Farrer formations approach 2,000 feet in thickness across much of the eastern part of the basin but thin to 1,000 feet over the Douglas Creek Arch. The Price River formation is estimated to approach 2,000 feet in thickness west of the Green River. These formations in central and southern Uinta are lithic arkoses and feldspathic litharenites (Fouch, 1992). To the north, sediments are quartz rich litharenites and sub-litharenites. The varied lithologies reflect the different major structural features existing during Late Cretaceous/Early Tertiary which contributed sediment to the Uinta Basin.

Approximately 43% of the Mesaverde group is composed of sandstone, estimated using a 50% V_{shale} cutoff applied to gamma ray logs. Fouch et al (1992) suggests that sandstones represent 70% of the Mesaverde group with the remainder being mud rock, coal and silty sandstone. Less than 10% of the Mesaverde section in the Uinta Basin is composed of marine sandstone (Fouch et, 1992). We estimate that only 4% of the Mesaverde sandstones are of sufficient quality to be considered as pay. By comparison, approximately 29% of the Wasatch Play is composed of sandstone, of which 7% are of high enough reservoir quality to be considered as pay.

Figure 30 presents the structure map of the top Mesaverde group in measured depth. Structures on the top and base of the Mesaverde Play (Figure 31) were constructed based on published formation tops (PI's WHCS) tops provided by the USGS and correlation of wireline logs. Mesaverde well control is extremely limited in the deeper parts of the basin and significant extrapolation of contours, particularly for the base of the play was necessary to delineate the deep synclinal play. Similarly, Mesaverde production data used to derive EURs and well logs used to determine pay counts and rock properties for the deep basin areas are sparse. Depth to the top of the play extends from formation outcrop at the basin edge to a projected 19,000 feet in the basin deep in north Uinta. Regional dip is 270 feet per mile to the northwest. This contrasts with the shallower 170 feet per mile for the overlying Wasatch formation and is a result of the wedging of the sedimentary section against the Cretaceous high in eastern Uinta coupled with continued basin subsidence during deposition. Figure 32 presents the Mesaverde structure in subsea. The basin outline is defined by the top Mesaverde/base Tertiary outcrop pattern. The Mesaverde gross section, Figure 33, ranges in thickness between 2,000 and 3,000 feet east of the Green River and is projected to increase to 4,000 feet in western Uinta. The gross interval mapped includes the Buck Tongue of the Mancos shale.

The Mesaverde sandstone isopach, Figure 34, was constructed using the product of the

gross thickness map and a gross/sandstone thickness ratio map. Sandstone thicknesses range between 1,000 feet to 1,500 feet across the Greater Natural Buttes Field area and thin to less than 500 feet across the basin's northeast flank. In the central portion of western Uinta thicknesses range between 1,000 feet and a projected 2,500 feet.

The Mesaverde pay isopach, Figure 35, displays thicknesses ranging from less than 25 feet to greater than 75 feet across the Greater Natural Buttes area. At Peters Point to the southwest, pay thicknesses average 50 feet. Immediately west of the Greater Natural Buttes area and west of the Green River, projected thicknesses are interpreted to reach greater than 80 feet, but thin again toward the north basin boundary. Deterioration of reservoir quality also occurs in the southeast part of the basin where pays are interpreted to thin to zero. Note that pay has been mapped outside the *demonstrated* area. Wireline logs indicate that reservoir quality rock exists over a wide area which has yet to demonstrate commercial production. At Peters Point for example, total Mesaverde production is only 17 MMcf. Though logs show pay, low matrix permeability generally requires the presence of well developed interconnected natural fractures to give up significant quantities of gas.

Figures 36a, 36b and 36c display rock property distributions for all sandstones lying within the gas-water transitional R_o 0.7-1.1, gas-saturated $R_o > 1.1$ & $< 15,000$ feet md, and gas-saturated deep synclinal $> 15,000$ feet md plays respectively. The bulk of sandstones within the Mesaverde have very low porosities and high water saturations. On average, only 4% of these sands have sufficiently good reservoir quality to be considered as pay. Porosities in the gas-saturated play are 2 to 3 porosity percent lower on average than those in the gas-water transitional play, which may be attributed partly to the increased overburden in the deeper play. However, the gas-saturated play has lower water saturations (79% versus 92% for the *demonstrated* area and 86% versus 90% for the *nondemonstrated* area) which appears to be a function of its higher thermal maturity. Rock properties for the deep synclinal play were based on average rock properties from the two deepest depth slices of the gas-saturated $R_o > 1.1$ & $< 15,000$ feet subplay. Well control within the deep synclinal play itself was not sufficient to develop a reasonable distribution of rock properties. Average porosities of pay sands increase slightly in comparison to porosities for all sandstones, but a substantial reduction in water saturation occurs as might be expected. Table 6 summarizes the rock property distributions used in the reserves calculations.

Porosity histograms plotted for 500 foot depth slices from wells located within the gas-saturated and gas-water transitional play areas (both *demonstrated* and *nondemonstrated*) display steadily decreasing porosities with increasing depth down to 11,500 feet md (Figure 37). Below this depth, the porosity distribution (not shown) displays negligible reduction. This porosity reduction appears to contradict Fouch et al's (1992) contention that Mesaverde porosities remain approximately constant as R_o values increase from 0.7 to 1.8% — the window of active hydrocarbon generation for Type III kerogen (Tissot and Welte, 1984). Note that R_o

values of 0.75% and 1.1% intersect the base of the Mesaverde, at least in the central part of the basin, east of the Green River at roughly 6,000-8,000 feet and 9,000 feet respectively. Fouch (1992) postulates that generating hydrocarbons displace water and potentially inhibit burial diagenesis, promoting expulsion rather than exchange of liquids, particularly if overpressuring occurs, while organic acids from the breakdown of kerogen may alter pore water chemistry and effect subsurface reactions. The implication being that porosities of Mesaverde sandstones in the deeper, *nondemonstrated* but thermally mature undrilled areas should be as good as those at 6,000 to 8,000 feet. The histograms on Figure 37 appear to suggest otherwise. The magnitude of porosity reduction as a function of increasing overburden is greatest above 3,000 to 4,000 psi (6,500 to 8,600 feet md) and decreases as overburden increases below this depth. Note however that the same plots using wells from only the *demonstrated* areas display a porosity reduction down to approximately 8,000 feet, while below this depth the porosity remains relatively unchanged.

Figure 38 represents an example computer processed interpretation (CPI) log for the Mesaverde Play. Well Devils Playground 41-9 (S9 T9S R24E) in the Natural Buttes Field was completed between the gross interval of 5,530 and 6,138 feet in 1978 with an IP of 48 Mcfd, 1 bcpd and 4 bwpd. This well was stimulated with 5,000 gallons of acid in three zones and fractured with 120,000 gallons of water and 225,000 pounds of sand. This well is dual completed in the Mesaverde and Wasatch. EUR for both formations is 315 MMcf.

Only 48 plug samples of Mesaverde core were collected and these were corrected to in-situ conditions and plotted as shown on Figure 39. Porosities range between 2 and 10%, averaging 6%. These are lower than the average porosities determined from log analysis, however, none of the core was sampled over completed intervals. In spite of data scatter, some semblance of a relationship between porosity and permeability exists. The P90, P50, P10 range of expected in-situ permeabilities determined from a probability plot of all measured permeabilities is 0.00001, 0.0015, and 0.03 millidarcies respectively.

Evaluation of Resource

The Mesaverde Play was divided into three subplays and then divided again into *demonstrated* and *nondemonstrated* areas. Average depths for the *demonstrated* area of the gas-saturated $R_o > 1.1$ & < 15,000 feet subplay and gas-water transitional R_o 0.7-1.1 subplay are 9,250 and 7,750 feet respectively with no rock volume below 11,500 feet. Most areas to the west of the Green River and south of Township 11S have been labeled *nondemonstrated* since no commercial production has yet been established. This includes all of the gas-saturated deep-synclinal > 15,000 feet play.

Existing production from the Mesaverde is dominated by the Natural Buttes Field which exhibits superior EURs in comparison to most other Mesaverde completions. All

Mesaverde wells were included in a distribution of expected recoveries constructed for *economic basement* calculations. The resulting "sweet spot" character of the distribution indicates that the EMV analysis and *economic basement* may err on the optimistic side. Even so, 87% of the wells are non-commercial based on an average depth of 6,810 feet. This model calculates an *economic basement* of 3,400 feet. Since there is no rock volume above 3,400 feet, there is no *established* resource in the Mesaverde. Deepest commercial production places a floor for consideration of reserves at 9,300 feet. Below this depth *demonstrated* resources are considered to be *speculative*.

Of the total resource of 335.6 Tcf evaluated for the Mesaverde, 81% (272 Tcf) occurs in low permeability rocks considered to be too tight to support commercial production. Of the remaining 63.6 Tcf, 81.6% (51.9 Tcf) is labeled *nondemonstrated* and is not available to be converted into reserves. All of the remaining 11.7 Tcf is below the *economic basement*.

Table 15 breaks down the resource estimate for the Mesaverde Play. Figures 40 through 44 graphically illustrate this break down for each subplay for both *demonstrated* and *nondemonstrated* categories.

TABLE 15
MESAVERDE PLAY, RESOURCE ESTIMATE BREAK DOWN

	GAS-SATURATED R_o > 1.1 & < 15,000 FT	GAS-WATER TRANSITION R_o 0.7-1.1	GAS-SATURATED DEEP SYNCLINAL > 15,000 FT	TOTAL
Scotia Mean Resource Estimate	200.7	87.1	47.8	335.6
Minus Technologically Nonviable Resources	163.0	68.1	40.9	272.0
Subtotal Technologically Viable Resources	37.7	19.0	6.9	63.6
Minus Nondemonstrated Resources	31.1	13.9	6.9	51.9
Subtotal Demonstrated Resources	6.6	5.1	0.0	11.7
Subdivision				
<i>Speculative Resources</i>	3.7	1.2	0.0	4.9
<i>Nonestablished Resources</i>	2.9	3.9	0.0	6.8
<i>Established Resources</i>	0.0	0	0.0	0.0

Reserves Evaluation

Input parameter distributions used in the probabilistic estimation of *nonestablished* reserves for the gas-saturated $R_o > 1.1$ & $< 15,000$ feet and gas-water transitional R_o 0.7-1.1 subplays are presented below along with the reserves probability results:

TABLE 16
MESAVERDE PLAY, RESERVES CALCULATION
NONESTABLISHED CATEGORY

	GAS-SATURATED R _o > 1.1 & < 15,000 FT			GAS-WATER TRANSITIONAL R _o 0.7-1.1		
Parameters	MAX	MOST LIKELY	MIN	MAX	MOST LIKELY	MIN
Base Recovery Factor	0.87	0.87	0.87	0.87	0.87	0.87
Dry Hole Fraction	0.12	0.12	0.12	0.12	0.12	0.12
Min Economic Drainage Acres	12	42	176	10	36	140
Noncommercial Fraction	0.2	0.77	0.92	0.18	0.72	0.9
Recovery Factor	0.61	0.18	0.06	0.63	0.21	0.08
Rock Volume (M ac-ft)	5,546			7,162		
Porosity	0.15	0.105	0.065	0.14	0.11	0.09
Water Saturation	0.4	0.49	0.58	0.4	0.475	0.55
FVF (res cf/scf)	0.00510	0.0047	0.0042	0.00810	0.00409	0.00450
<u>Reserves Probability Distribution</u>						
90% Probability of Exceeding (Bcf)	336			462		
70% Probability of Exceeding (Bcf)	527			691		
50% Probability of Exceeding (Bcf)	710			902		
30% Probability of Exceeding (Bcf)	935			1,168		
10% Probability of Exceeding (Bcf)	1,315			1,586		
Mean Value (Bcf)	775			974		
<u>PDP Reserves & Cum Production</u>						
Cumulative Production (Bcf)				38.2		
Remaining PDP Reserves (Bcf)				8.1		
EUR of PDP Reserves (Bcf)				46.3		

In summary, reserves are recognized in the *nonestablished* category in the Mesaverde. The mean estimate for *nonestablished* reserves is 1,749 Bcf or 1,703 Bcf after subtraction of EURs of existing Mesaverde wells.

Figure: 24

LEGEND

☆ GAS WELL	— BASIN OUTLINE
• OIL WELL	— USGS PLAY OUTLINE
○ DRY HOLE	— RIVERS

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

U.S. Department of Energy

Uinta Basin MESAVERDE PLAY PENETRATION MAP

Prepared by The Scotia Group, Inc.

Figure: 25

Figure: 26

FIGURE 27

MESAVEVERDE TOTAL PRODUCTION PROFILE

Projections are averages for each year commencing at the effective date of the evaluation. Results are subject to the qualifications and limitations stated in the attached document

MESAVERDE PLAY

Technical Success 88.0%
Commercial Success 11.4%

DRILLING RESULTS

Figure: 29

BACULITES ASPERIFORMIS
EARLY-LATE CAMPANIAN

BACULITES PERPLEXUS
MIDDLE-LATE CAMPANIAN

DIDYMO CERAS NEBRASCENSE
LATE CAMPANIAN

BACULITES CUNEATUS
LATE-LATE CAMPANIAN

Constructed For Selected
Western Interior Molluscan
Fossil Zones
Modified From Fouch Et Al 1992

U.S. Department of Energy

Uinta Basin
CAMPANIAN MESAVERDE
PALEOGEOGRAPHIC RECONSTRUCTIONS

Prepared by The Scotia Group, Inc.

Figure: 30

10. 0. 10. 20. 30. 40. 50. miles

LEGEND

- BASIN OUTLINE
- CONTOURS, FT.

U.S. Department of Energy

Uinta Basin
MESAVERDE PLAY
TOP STRUCTURE, MEASURED DEPTH

Prepared by The Scotia Group, Inc.

Figure: 31

Figure: 32

Figure: 33

Figure: 34

Figure: 35

Uinta Basin: Rock Property Distributions

GAS-WATER TRANSITIONAL Ro .7-1.1, DEMONSTRATED

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Uinta Basin: Rock Property Distributions

GAS-SATURATED $R_o > 1.1$ & $< 15,000'$, DEMONSTRATED

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Uinta Basin: Rock Property Distributions

GAS-SATURATED $R_o > 1.1$ & $< 15,000'$, NONDEMONSTRATED

FRI SEP 01 1995

Uinta Basin: Rock Property Distributions

GAS-SATURATED DEEP SYNCLINAL > 15,000', NONDEMONSTRATED

FRI SEP 01 1995

Uinta Basin: Rock Properties by Depth

MESAVERDE PLAY

WED SEP 06 1995

0 Bad Hole Flag 20
6 ----- Caliper ----- 16
0 ----- Gamma Ray ----- 150
0 75 150

DEPTH

1.00 — Sw — -1.0
0.00 ----- Vclay minimum ----- 2.00
0.60 ----- Phi.Sw ----- 0.00
0.60 ----- Phi.Sxo ----- 0.00
0.60 ----- Effective Porosity ----- 0.00
10⁻⁴ ----- SFL Resistivity ----- 100
10⁻⁴ ----- Deep Induction ----- 100
10⁻⁴ ----- Permeability (Alt) ----- 100
10⁻⁴ ----- Permeability (Kokal) ----- 100
0.60 0.45 0.30 0.15 0.00 10⁻⁴ .001 0.01 0.1 1 10 100

FILE: 9249M

5400

5500

5600

5700

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FILE: 9249M

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SAT SEP 02 1995

FILE: 9249M

Scotia Group Proprietary Systems

SAT SEP 02 1995

Figure 39

COREPRO Client: U.S. DEPARTMENT OF ENERGY
INSITU CONDITION, MESAVERDE PLAY, ALL DATA.
Porosity versus Permeability

COREPRO Client: U.S. DEPARTMENT OF ENERGY
INSITU CONDITION, MESAVERDE PLAY, ALL DATA.
Histogram Plot

COREPRO Client: U.S. DEPARTMENT OF ENERGY
INSITU CONDITION, MESAVERDE PLAY, ALL DATA.
Probability Paper Plot

COREPRO Client: U.S. DEPARTMENT OF ENERGY
INSITU CONDITION, MESAVERDE PLAY, ALL DATA.
Porosity versus Storage Capacity

Uinta Basin Tight Gas Resource Allocation

GAS-WATER TRANSITIONAL Ro .7-1.1 SUBPLAY, DEMONSTRATED

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Uinta Basin Tight Gas Resource Allocation

GAS-SATURATED $R_o > 1.1$ & $< 15,000'$ SUBPLAY, DEMONSTRATED

FRI SEP 01 1995

Uinta Basin Tight Gas Resource Allocation

GAS-WATER TRANSITIONAL Ro .7 - 1.1 SUBPLAY, NONDEMONSTRATED

FRI SEP 01 1995

Uinta Basin Tight Gas Resource Allocation

GAS-SATURATED, $R_o > 1.1$ & $< 15,000'$ SUBPLAY, NONDEMONSTRATED

Uinta Basin Tight Gas Resource Allocation

GAS-SATURATED DEEP SYNCLINAL >15000' SUBPLAY, NONDEMONSTRATED

WASATCH PLAY

Description

The Wasatch Play overlies the Mesaverde. For the purposes of this study, the Wasatch has been broken down into two subplays, the gas-saturated and gas-water transitional subplays, which cover approximately 823 and 840 square miles respectively. The gas-saturated subplay roughly corresponds to the USGS plays 2015 and 2016. The gas-water transitional subplay is a significantly reduced version of USGS Play 2017. Initially, the subplay boundary to the east and south corresponded to the R_o 0.7 line as it intersects the base of the Mesaverde Play. Figures 5 and 6 illustrate that the bulk of the Wasatch is actually immature, being situated for the most part above an R_o of 0.75. Across Natural Buttes however the Wasatch is productive and is sourced by the underlying Mesaverde where mature (Fouch, 1992). Consequently, assuming predominantly vertical migration via faults and fractures, the Mesaverde subplay boundaries which delineate the thermally mature area should also correspond to the gross potentially productive limits of the Wasatch formation. Outside the Natural Buttes area however, limited well control shows very little evidence of gas-saturated reservoir quality rock in the gas-water transitional subplay. Production and well test records also indicate that this area has not been *demonstrated* to be productive. Consequently, because the Wasatch formation is immature and does not display a continuous gas-saturated phase typical of Masters' (1979) basin centered tight gas accumulations, but rather relies on stratigraphic trapping of Mesaverde-sourced gas via fractures which do not appear to be sufficiently developed outside Natural Buttes, the *nondemonstrated* region of the gas-water transitional subplay has been dropped from consideration. Though the gas-saturated subplay is broken out into *demonstrated* and *nondemonstrated* areas, the gas-water transitional subplay is limited to an area around Greater Natural Buttes which is considered to be *demonstrated*.

To the north and west, the Wasatch gas-saturated play boundary corresponds to an approximation of the position beyond which the oil prone lacustrine and marginal lacustrine Green River beds become dominant. Significant inter-tonguing of the Green River and Wasatch formations, resulting from periodic structural and climate controlled expansion and contraction of Lake Uinta, coupled with periodic influx of alluvial sediments, make the positioning of the Wasatch north and west play boundary difficult. Fouch (1994) notes that this boundary approximates the position of the R_o 1.5 line as it intersects the base of the Mesaverde group.

Well control within the play is generally good east of the Green River, but deteriorates to the south. Wells include Wasatch completions plus penetrations through the Wasatch into the Mesaverde. (Figure 45). Also displayed are the original USGS play boundaries. In contrast, the Scotia play boundaries are shown in Figure 46 along with the FERC-designated tight area around the Natural Buttes Field.

The Wasatch Field list, Table 17, shows cumulative production of 413 Bcf from 921 wells. The EURs of these wells are 567 Bcf of an average of 615 MMcf/well. The Natural Buttes Field dominates this play, accounting for 92% (863) of the wells and 96% (545.7 Bcf) of the EUR. The next largest field in the play has only 14 wells. The only Wasatch production west of the Green River follows the Nine Mile Creek, otherwise most of the production is centered around Natural Buttes (Figure 47). Examination of the play level production profile (Figure 48) indicates approximately 634 wells are currently producing with average per well rates of 204 Mcfd. The production plot also suggests curtailment during the 1980s. Also evident is the rapid development since 1991.

Analysis of the Wasatch drilling statistics is complicated by the fact that many Wasatch completed wells TD in the Mesaverde. Considering only those wells with Wasatch TD, 29% were dry holes. These numbers are however skewed by wells located outside the play boundaries which were subsequently removed from consideration. Since reserves are only calculated for the *demonstrated* area, wells lying in the *nondemonstrated* area were also dropped from consideration. The resulting dry hole factor used in the reserves evaluation was 2%.

Stratigraphy and Rock Properties

All strata of the Paleocene-Eocene alluvial Wasatch and Colton formations, plus the alluvial North Horn Formation and intertonguing and undifferentiated open and marginal lacustrine, Green River and Flagstaff beds which unconformably overlie the Mesaverde group and underlie the Green River Formation proper, were considered for inclusion in the Wasatch Play. These alluvial sequences which represent the main nonassociated gas formations in this play commonly consist of variegated red and green sandstone and claystone units. They represent the updip depositional equivalents of oil bearing mixed carbonate and clastic rock sequences which formed near the center of the lacustrine system. The channel sands flowed either south from the Uinta Uplift or northwest from the southern highlands. Productive sandstones are usually isolated and encased in variegated red and brown siltstones, mudstones and shales (Osmond, 1992). Fouch et al and others (1992) and Franczyk and others (1992) reconstructed the paleogeography of the Tertiary section using western interior molluscan fossil zones, three of which are used here to provide snapshots in time during Paleocene and Eocene deposition (Figure 49). The lowest interval (the lower marker of the Paleocene) represents a time slice through a wedge of inter-tonguing marginal lacustrine sediments of the Flagstaff member of the Green River Formation and alluvial North Horn sediments. Sediments include varying colored shales, fluvial sandstones and lacustrine limestone and coal. The wedge unconformably onlaps Cretaceous strata of the Uncompahgre Uplift and Douglas Creek Arch, and pinches out 20 to 30 miles east of the Green River, along a northeast strike. Across Greater Natural Buttes, the wedge is usually 1,000 feet thick or less but thickens to more than 2,300 feet west of the Green River across the west part of the play area. Sands

within this section are oil and gas productive at Altamont Bluebell (Fouch et al, 1992) and gas productive at Greater Natural Buttes.

TABLE 17
WASATCH PLAY FIELD LIST

FIELD NAME	AVG DEPTH (Feet)	CUM MMcf	EUR MMcf	NUMBER OF WELLS	AVG EUR MMcf/WELL
Bonanza	5,832	367	367	2	184
Buck Canyon	5,182	514	514	5	103
Devils Playground	5,313	932	942	2	471
East Bench	4,432	62	62	1	62
Hill Creek	4,851	27	27	1	27
Love	5,477	1,694	1,767	6	294
Natural Buttes	5,937	394,530	545,732	846	645
Nine Mile Canyon	3,913	558	558	1	558
Oil Springs	2,758	2,959	3,599	7	514
Peters Point	3,197	3,673	3,767	8	471
Pine Springs	1,917	611	611	3	204
Red Wash Greater	6,343	12	29	1	29
Rock House	4,594	5,552	6,293	14	450
Sand Ridge	5,134	53	53	1	53
Stone Cabin	4,711	441	491	2	246
Undesignated	6,139	8	9	1	9
Unnamed 11-11S19E	6,031	308	308	1	308
Unnamed 12-9S19E	6,769	47	47	1	47
Unnamed 27-12S15E	5,015	869	1,330	1	1,330
TOTAL		413,217	566,506	904	627

The second and third time slices, the Paleocene-Eocene boundary and the middle marker of the Green River Formation respectively, illustrate the changing relationship between the alluvial sediments of the Wasatch and equivalent Colton formations and the open lacustrine and marginal lacustrine Green River Formation. Periodic structural and climate (solar) controlled expansion and contraction of Lake Uinta (Fouch et al, 1992), coupled with periodic influx of alluvial sediments created a complicated intertonguing of these two depositional facies. At Natural Buttes the Wasatch generally consists of alluvial red shale and siltstones. The Wasatch and associated interbedded strata ranges in thickness from 500 to 5,000 feet across the Uinta Basin. The lower portion of this sequence pinches out against the Uncompahgre Uplift in east Uinta. At Natural Buttes the Wasatch ranges from 3,000 to 2,000 feet in thickness. The major nonassociated gas productive areas for the Wasatch include Greater Natural Buttes and Peters Point, approximately 20 miles southwest of Greater Natural Buttes.

The mineral composition of the Wasatch sediments is related to the geographic location of the sediment source. To the north at Altamont and Redwash, sediments sourced by the granites of the Uinta mountains are quartz rich. To the south at Natural Buttes and Pariette Bench the Wasatch is more feldspathic and lithic-rich, being sourced by the Laramide Uplift to the south.

Figure 50 presents the structure map of the top Wasatch Formation in measured depth, constructed using tops from the PI WHCS database. Depth to the top of the Wasatch formation extends from formation outcrop at the basin edge to approximately 13,000 feet in the basin deep at northern Uinta. Regional dip to the north and northwest is approximately 170 feet per mile. Major structural features within the Uinta Basin are generally absent as indicated by this map. Figure 51 presents the Wasatch Formation structure in subsea.

The Wasatch Play gross interval, Figure 52, increases in thickness from less than 500 feet at the basin's north and eastern margins to over 4,000 feet in the western half of the basin. This change in thickness is a result of pinch out of the lower section against the Cretaceous strata of the Uncompahgre Uplift in the east and continued subsidence of the basin depocenter to the north.

The Wasatch sandstone isopach, Figure 53, thickens from less than 150 feet at the basin's east and northern margins to approximately 1,500 feet in the western half of the basin. Again, this thinning is related to onlap against the Uncompahgre high.

The Wasatch pay isopach, Figure 54, shows the best reservoir quality sandstones to be centered around the northwestern part of the Greater Natural Buttes Field and around Peters Point where greater than 70 feet of pay are mapped. Except for Peters Point, pay sands thin

and reservoir quality deteriorates west of the Green River. Similarly, thinning of pay quality sands occurs to the southeast.

Figures 55a through 55d display rock property distributions for all sands within the demonstrated and nondemonstrated areas of the gas-saturated and gas-water transitional plays. Note the porosity distributions which are heavily skewed toward low values and the very high water saturations. These figures illustrate the overall poor reservoir quality of most Wasatch sands. On average 7% of these sands are of sufficient quality to be considered as pay. In spite of porosities being generally lower (4%-5% versus 7.5% mode) in the gas saturated play corresponding water saturations are also lower (78% versus 90%-94% mode). This difference may be attributed to a generally weaker gas charge in the Wasatch gas-water transitional play from thermally less mature Mesaverde source rock. The lower porosities of the gas saturated play may be partially attributed to greater overburden. Very little difference exists between rock properties of the *demonstrated* and *nondemonstrated* regions in the gas-saturated play. In the gas-water transitional play however, water saturations are higher in the *nondemonstrated* region. The implication that a higher percentage of sands has not been gas-charged may be related to a reduction in fracturing outside the *demonstrated* area. Porosities increase and water saturation drops substantially for the pay sands as summarized in the reserves calculations, Table 19.

Figure 56 is an example of a CPI log from the Wasatch Play. The Natural Buttes #26 is located in the Natural Buttes Field at S27 T9S R21E. The well tested 700Mcf/d 117,000 pounds between 5,625 and 5,865 feet following an acid frac with 63,000 gallons of acid and of sand. This well produced 590 MMcf in eight years. Average porosity over the 21 foot pay interval is 11.7% and water saturation averages 56%. Note the increased resistivity with depth. The higher resistivities below about 6,730 feet md are typical of the Paleocene North Horn formation and Flagstaff member of the Green River formation, whereas the lower resistivities above are typical of the Wasatch alluvial red beds and fluvial sand. Except for this distinction, the Wasatch section generally represents a characterless repetition of difficult to correlate shales, silts and sands.

A total of 1,212 plug samples of Wasatch core were corrected to in-situ conditions and split into three categories: completed, tested and other samples, Figures 57a and 57b. Note the high incidence (65%) of low porosity samples for which permeabilities were not measured. The P90, P50, P10 range of expected in-situ permeabilities determined from a probability plot of all measured permeabilities is 0.0001, 0.003 and 1 millidarcies. Considering data from 26 wells are combined in one plot, a relatively reasonable relationship can be seen between porosity and permeability. Only 51 samples were available from completed intervals which display a 2% to 20% porosity range, averaging 12.5%. This compares with the 8% to 18% porosity range (average 10%) for pay derived from log analysis.

Reevaluation of Resource

All of the rock resource for the Wasatch *demonstrated* play lies above 8,000 feet. The *nondemonstrated* rock volume lies between 4,500 and 8,500 feet.

The existing production from the Wasatch is dominated by the Natural Buttes Field which exhibits superior EURs in comparison to most other Wasatch production. Though the distribution of expected recoveries constructed for *economic basement* calculations includes all productive Wasatch wells, it has a definite sweet spot character. This may cause the EMV analysis and the *economic basement* determination to err on the optimistic side. This model calculated an *economic basement* at 6,150 feet. Deepest commercial production places a floor for reserves consideration at 7,400 feet. Below this depth resources are considered *speculative*. Figure 58 illustrates the EUR distributions and the Wasatch *demonstrated* risk model.

Of total resources of 59.9 Tcf evaluated for the Wasatch, 88% (52.8 Tcf) occurs in low permeability rocks. Of the remaining 7.1 Tcf, 17% (1.2 Tcf) is labeled *nondemonstrated*, leaving 5.9 Tcf of which 31% (2.1 Tcf) is below the *economic basement*.

Table 18 lists the resource estimate break down for both Wasatch subplays.

TABLE 18
WASATCH PLAY RESOURCE ESTIMATE BREAK DOWN

	GAS-SATURATED	GAS-WATER TRANSITIONAL	TOTAL
Scotia Mean Resource Estimate	39.7	20.2	59.9
Minus Technologically Nonviable Resources	35.2	17.6	52.8
Subtotal Technologically Viable Resources	4.5	2.6	7.1
Minus Nondemonstrated Resources	1.2	0.0	1.2
Subtotal Demonstrated Resources	3.3	2.6	5.9
Subdivision			
Speculative Resources	0.3	0.0	0.3
Nonestablished Resources	1.6	0.2	1.8
Established Resources	1.4	2.4	3.8

Figures 59, 60, and 61 graphically illustrate this breakdown.

Reserves Evaluation

Established and *nonestablished* reserves estimates have been made for each of the Wasatch subplays. Tables 19 and 20 below represent the input parameter distributions and the resulting reserves probabilities for the gas-saturated and gas-water transitional subplays respectively.

TABLE 19
RESERVES CALCULATION, GAS-SATURATED SUBPLAY

	ESTABLISHED CATEGORY			NONESTABLISHED CATEGORY		
Parameters	Max	Most Likely	Min	Max	Most Likely	Min
Base Recovery Factor	0.81	0.81	0.81	0.81	0.81	0.81
Dry Hole Fraction	0.02	0.02	0.02	0.02	0.02	0.02
Min Economic Drainage Acres	13	36	110	18	50	150
Noncommercial Fraction	0.18	0.56	0.77	0.26	0.55	0.81
Recovery Factor	0.65	0.44	0.18	0.59	0.35	0.15
Rock Volume (M ac-ft)	3,620			3,486		
Porosity	0.135	0.105	0.085	0.14	0.105	0.085
Water Saturation	0.48	0.515	0.55	0.42	0.485	0.55
FVF (res cf/scf)	0.008	0.0063	0.0054	0.0054	0.0049	0.0049
Reserves Prob Distribution						
90% Probability of Exceeding (Bcf)	377			380		
70% Probability of Exceeding (Bcf)	443			497		
50% Probability of Exceeding (Bcf)	523			596		
30% Probability of Exceeding (Bcf)	604			697		
10% Probability of Exceeding (Bcf)	721			857		
Mean Value (Bcf)	528			608		

TABLE 20
RESERVES CALCULATION, GAS-WATER TRANSITIONAL SUBPLAY

	<i>ESTABLISHED</i> CATEGORY			<i>NONESTABLISHED</i> CATEGORY		
Parameters	Max	Most Likely	Min	Max	Most Likely	Min
Base Recovery Factor	0.81	0.81	0.81	0.81	0.81	0.81
Dry Hole Fraction	0.02	0.02	0.02	0.02	0.02	0.02
Min Economic Drainage Acres	12	35	100	15	44	130
Noncommercial Fraction	0.17	0.43	0.73	0.20	0.5	0.80
Recovery Factor	0.66	0.45	0.21	0.64	0.40	0.16
Rock Volume (M ac-ft)	6,528			456		
Porosity	0.135	0.105	0.085	0.15	0.105	0.08
Water Saturation	0.48	0.515	0.55	0.38	0.48	0.58
FVF (res cf/scf)	0.0168	0.0074	0.0051	0.00531	0.00521	0.00511
Reserves Probability Distribution						
90% Probability of Exceeding (Bcf)	436			51		
70% Probability of Exceeding (Bcf)	592			68		
50% Probability of Exceeding (Bcf)	741			83		
30% Probability of Exceeding (Bcf)	921			98		
10% Probability of Exceeding (Bcf)	1,256			124		
Mean Value (Bcf)	800			85		

Table 21 presents the reserves probabilities combined from both subplays.

TABLE 21
CUMULATIVE RESERVES PROBABILITY DISTRIBUTION
FOR BOTH SUBPLAYS

RESERVES PROBABILITY DISTRIBUTION	ESTABLISHED	NONESTABLISHED
90% Probability of Exceeding (Bcf)	773	431
70% Probability of Exceeding (Bcf)	1,035	565
50% Probability of Exceeding (Bcf)	1,264	679
30% Probability of Exceeding (Bcf)	1,525	795
10% Probability of Exceeding (Bcf)	1,977	981
Mean Value (Tcf)	1,328	693
<u>PDP Reserves & Cum Production</u>		
Cum Production (Bcf)	318	92
Remaining PDP Reserves (Bcf)	110	42
EUR of PDP Reserves (Bcf)	428	134

In summary, reserves are recognized in both the *established* and *nonestablished* categories in the Wasatch subplays. The mean estimate for *established* reserves is 1,328 Bcf overall or 900 Bcf after subtraction of the EURs of existing Wasatch wells. *Nonestablished* reserves are recognized with a mean estimate of 693 Bcf overall or 554 Bcf after subtraction of the EURs of existing Wasatch wells.

Figure: 45

LEGEND

☆ GAS WELL	— BASIN OUTLINE
• OIL WELL	— USGS PLAY OUTLINE
○ DRY HOLE	— RIVERS

Well locations were obtained from Petroleum Information. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

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Uinta Basin
WASATCH PLAY
PENETRATION MAP

Prepared by The Scotia Group, Inc.

Figure: 46

Figure: 47

FIGURE 48

WASATCH TOTAL PRODUCTION PROFILE

Projections are averages for each year commencing at the effective date of the evaluation. Results are subject to the qualifications and limitations stated in the attached document

Figure: 49

LOWER MARKER OF PALEOCENE AND
EOCENE FLAGSTAFF MEMBER OF THE
GREEN RIVER FORMATION

PALEOCENE-EOCENE BOUNDARY

MIDDLE MARKER OF THE
GREEN RIVER FORMATION

Constructed For Selected
Stratigraphic Markers
Modified From Fouch Et Al 1992

U.S. Department of Energy

Uinta Basin
PALEOCENE-EOCENE
PALEOGEOGRAPHIC RECONSTRUCTIONS

Prepared by The Scotia Group, Inc.

Figure: 50

LEGEND

- BASIN OUTLINE
- CONTOURS, FT.

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Uinta Basin
WASATCH PLAY
TOP STRUCTURE, MEASURED DEPTH

Prepared by The Scotia Group, Inc.

Figure: 51

LEGEND

- BASIN OUTLINE
- CONTOURS, FT.

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Uinta Basin
WASATCH PLAY
TOP STRUCTURE, SUBSEA

Prepared by The Scotia Group, Inc.

Figure:52

LEGEND

- BASIN OUTLINE
- CONTOURS, FT.

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Uinta Basin
WASATCH PLAY GROSS ISOPACH

Prepared by The Scotia Group, Inc.

Figure:53

LEGEND

- BASIN OUTLINE
- CONTOURS, FT.

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Uinta Basin

WASATCH PLAY SANDSTONE ISOPACH

Prepared by The Scotio Group, Inc.

Figure:54

Uinta Basin: Rock Property Distributions
WASATCH PLAY, GAS-SATURATED, DEMONSTRATED

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Uinta Basin: Rock Property Distributions

WASATCH PLAY, GAS-WATER TRANSITIONAL, DEMONSTRATED

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Uinta Basin: Rock Property Distributions
WASATCH PLAY, GAS-SATURATED, NONDEMONSTRATED

FRI SEP 01 1995

Uinta Basin: Rock Property Distributions

WASATCH PLAY, GAS-WATER TRANSITIONAL, NONDEMONSTRATED

FRI SEP 01 1995

0 Bad Hole Flag 20
6 Caliper 16
0 Gamma Ray 150
0 75 150

DEPTH

5600

5700

5800

5900

6000

1.00 Sw -1.0
0.00 Vclay minimum 2.00
0.60 Phi Sw 0.00
0.60 Phi.Sxo 0.00
0.60 Effective Porosity 0.00
0.60 0.45 0.30 0.15 0.00
10⁻⁴ SFL Resistivity 100
10⁻⁴ Deep Induction 100
10⁻⁴ Permeability (Alt) 100
10⁻⁴ Permeability (Kukal) 100
10⁻⁴ 0.001 0.01 0.1 1 10 100

FILE: 92127W1

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SAT SEP 02 1995

0 Bad Hole Flag 20
6 Caliper 16
0 Gamma Ray 150
0 75 150

DEPTH

6000

6100

6200

6300

6400

1.00	Sw	-1.0		
0.00	Vclay minimum	2.00	10 ⁻⁴	SFL Resistivity
0.60	Phi.Sw	0.00	10 ⁻⁴	Deep Induction
0.60	Phi.Sxo	0.00	10 ⁻⁴	Permeability (Alt)
0.60	Effective Porosity	0.00	10 ⁻⁴	Permeability (Kokal)

0.60 0.45 0.30 0.15 0.00 10⁻⁴ .001 0.01 0.1 1 10 100

FILE: 92127W1

Scotia Group Proprietary Systems

SAT SEP 02 1995

0 Bad Hole Flag 20
6 Caliper 16
0 Gamma Ray 150
0 75 150

FILE: 92127W1

DEPTH

6400

6500

6600

6700

6800

1.00 Sw -1.0
0.00 Vclay minimum 2.00 10⁻⁴ SFL Resistivity 100
0.60 Phi.Sw 0.00 10⁻⁴ Deep Induction 100
0.60 Phi.Sxo 0.00 10⁻⁴ Permeability (Alt) 100
0.60 Effective Porosity 0.00 10⁻⁴ Permeability (Kukal) 100
0.60 0.45 0.30 0.15 0.00 10⁻⁴ .001 0.01 0.1 1 10 100

Scotia Group Proprietary Systems

SAT SEP 02 1995

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Scotia Group Proprietary Systems

MON SEP 11 1995

0 Bad Hole Flag 20
6 Caliper 16
0 Gamma Ray 150
0 75 150

DEPTH

7200

7300

7400

7500

1.00	Sw	-1.0										
0.00	Vclay minimum	2.00	10 ⁻⁴	SFL Resistivity								
0.60	Phi.Sw	0.00	10 ⁻⁴	Deep Induction								
0.60	Phi.Sxo	0.00	10 ⁻⁴	Permeability (Alt)								
0.60	Effective Porosity	0.00	10 ⁻⁴	Permeability (Kukal)								
0.60		0.45	0.30	0.15	0.00	10 ⁻⁴	.001	0.01	0.1	1	10	100

FILE: 92127W2

Scotia Group Proprietary Systems

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Figure 57a

COREPRO Client: U.S. DEPARTMENT OF ENERGY
INSITU CONDITION, WASATCH PLAY, ALL DATA.
Porosity versus Permeability

COREPRO Client: U.S. DEPARTMENT OF ENERGY
INSITU CONDITION, WASATCH PLAY, ALL DATA.
Histogram Plot

AVERAGE 4.24 POINTS 1212.
MEDIAN 3.24 STD DEV 3.20

COREPRO Client: U.S. DEPARTMENT OF ENERGY
INSITU CONDITION, WASATCH PLAY, COMPLETED INTERVALS.
Porosity versus Permeability

COREPRO Client: U.S. DEPARTMENT OF ENERGY
INSITU CONDITION, WASATCH PLAY, COMPLETED INTERVALS.
Histogram Plot

AVERAGE 4.40 POINTS 426.
MEDIAN 3.15 STD DEV 3.96

COREPRO Client: U.S. DEPARTMENT OF ENERGY
INSITU CONDITION, WASATCH PLAY, TESTED INTERVALS.
Porosity versus Permeability

Figure 57b

COREPRO Client: U.S. DEPARTMENT OF ENERGY
INSITU CONDITION, WASATCH PLAY, TESTED INTERVALS.
Histogram Plot

COREPRO Client: U.S. DEPARTMENT OF ENERGY
INSITU CONDITION, WASATCH PLAY, OTHER DATA.
Porosity versus Permeability

Figure 57d

COREPRO Client: U.S. DEPARTMENT OF ENERGY
INSITU CONDITION, WASATCH PLAY, OTHER DATA.
Histogram Plot

WASATCH PLAY

Technical Success 98.0%
Commercial Success 53.9%

Uinta Basin Tight Gas Resource Allocation

WASATCH PLAY, GAS-SATURATED DEMONSTRATED

Uinta Basin Tight Gas Resource Allocation

WASATCH PLAY, GAS-WATER TRANSITIONAL DEMONSTRATED

Uinta Basin Tight Gas Resource Allocation
WASATCH PLAY, GAS-SATURATED NONDEMONSTRATED

FRI SEP 01 1995

GLOSSARY OF ABBREVIATIONS

API	American Petroleum Institute
Bcf	Billion Cubic Feet
bcpd	Barrels of Crude Per Day
bwpd	Barrels of Water Per Day
CPI	Computer Processed Interpretation
DST	Drillstem Test
EMV	Expected Monetary Value
EUR	Estimated Ultimate Recovery
FERC	Federal Energy Regulatory Commission
GGRB	Greater Green River Basin
GIP	Gas In-Place
IP	Initial Potential
md	Measured Depth
Mbo	Thousand Barrels of Oil
MWX	Multiwell Experiment
NOB	Net Overburden
NPS	National Production System
PDP	Proved Developed Producing
PI	Petroleum Information Corporation
scf	Standard Cubic Feet
SEC	Securities and Exchange Commission
SP	Spontaneous Potential
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
Tcf	Trillion Cubic Feet
TD	Total Depth
USBM	U.S. Bureau of Mines
USGS	U.S. Geological Survey
WHCS	Well History Control System

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APPENDIX A

SENSITIVITY OF *ECONOMIC BASEMENT* TO GAS PRICE

A premise of this study was the use of a \$2.00/Mcf wellhead gas price. While the examination of alternative price scenarios was not part of the scope of the study, the importance of higher gas prices in unlocking major volumes of additional gas supply is widely recognized. The following is a brief analysis of the effect of gas price changes on *economic basement*.

As the wellhead gas price changes, the *economic basement* changes inversely. As the gas price goes up, the *economic basement* deepens, as the gas price drops, the *economic basement* is raised. Since gas price is dynamic, it is of great interest to determine the amount of extra net pay rock volume that is added or subtracted to the *established* reserves calculation based on the fluctuation in gas price. The table below lists net pay rock volume above the *economic basement* for seven pricing scenarios ranging between \$2.00, and \$5.00 gas.

NET PAY ROCK VOLUME ABOVE ECONOMIC LIMIT
M AcFt

PLAY	\$2.00	\$2.50	\$3.00	\$3.50	\$4.00	\$4.50	\$5.00
Mesaverde	—	463	1,053	2,046	4,023	7,711	14,443
Wasatch	10,148	14,651	14,692	14,692	14,692	14,692	14,692

Figures A-1 and A-2 graphically show this information in plots of depth versus cumulative net pay.

Since gas price can be directly associated with subsurface elevation, *economic basement* contours can be constructed for each gas price scenario which define areas within each play where the rewards outweigh the costs of drilling.

Figures A-3 and A-4 show these *economic basement* contours superimposed on the net pay contours for the Mesaverde and Wasatch plays respectively. Note that the *economic basement* contours are drawn on the structure representing the mid-point of the gross interval of each play. Consequently, if wells are typically completed in the upper portion of the play, rather than across the full gross section, the contour locations will be conservative.

Figure A-3 illustrates that the bulk of the Mesaverde Play is uneconomic at \$2.00 gas prices. Gas prices must increase to between \$3.00 and \$5.00 for the play to become economic across the Natural Buttes area. Dually completing or commingling with the overlying Wasatch Play would improve the *economic basement* picture.

In Figure A-4 the \$2.00 *economic basement* contour passes over the center of the Natural Buttes Field, suggesting that north of the contour the field is uneconomic at \$2.00 gas prices. Actually 73% of Wasatch completions lie within the upper 42% of the formation. Consequently, the location of the \$2.00 *economic basement* contour is conservative and should lie at some point between its mapped position and its intersection with the top of the play, that is, approximately the north-west boundary of the field.

FIGURE A-1

FIGURE A-2

LEGEND

- BASIN OUTLINE
- CONTOURS

U.S. Department of Energy

Uinta Basin
MESAVERDE PLAY
ECONOMIC BASEMENT MAP

Prepared by The Scotia Group, Inc.

Figure: A-4

LEGEND

- BASIN OUTLINE
- ECONOMIC BASEMENT(\$)
- NET PAY

U.S. Department of Energy

Uinta Basin
WASATCH PLAY
ECONOMIC BASEMENT MAP

Prepared by The Scotia Group, Inc.