EVALUATION OF ASSETS

La Rosa Field
Refugio County, Texas

Prepared For

Datinvest International Ltd.

By

Quantum Oil & Gas, LLC

Effective Date

May 21, 2007

Table of Contents

I. Letter of Transmittal to Datinvest International Ltd.

QUANTUM OIL & GAS, LLC.

305 Clearview Ave., Friendswood, TX 77546 Phone: (713) 826-5828
Email: wes713@msn.com

May 21 2007

Jason Birmingham (Pres.)
Datinvest International Ltd
PO Box 49290 1000 - 595 Burrard St.
Vancouver BC
V7X 1S8
Phone (604) 647-4176 Fax (604) 683-5371

Dear Sir:

Re: Evaluation of Datinvest International Ltd. Assets, Exploitation and Drilling Program, La Rosa Field, Refugio County, Texas

As requested, Quantum Oil & Gas, LLC (hereafter referred to as “Quantum”) has prepared an evaluation of the proposed assets and interests of Datinvest (hereafter referred to as the "Company" or “Datinvest”) to be acquired from Laroco LLP (“Laroco”) in accordance with Canadian Securities Administrator’s National Instrument 51-101-Standards of Disclosure for Oil and Gas Activities (“NI 51-101”). The evaluation is prepared using an effective date of May 21, 2007. The purpose of this evaluation is for a proposed “change of business” filing with the TSX Venture Exchange.

This report has been prepared pursuant to Section 5.10(2) (b) of NI 51-101where the value of the properties cannot be determined on the basis of recent financial transactions related to the property, such as acquisition cost, but where resource quantities and estimates of fair value associated with the interests of the reporting issuer are based on a professional valuator.

Authority:

Quantum Oil & Gas, LLC represented herein by Wesley Franklin, has been engaged and authorized to prepare this report by Jason Birmingham, President of Datinvest International Ltd.

Sources of Information:

Information used in the preparation of this report was obtained from Datinvest, or was provided by others at the request of Datinvest. In preparation of this report we have relied, without independent verification, upon information furnished by, or on behalf of, Datinvest with respect to the property interests to be evaluated, activity and production from such properties, current costs of operation and development, current prices for production, agreements relating to current future operations and sales of production, agreements relating to current and future operations and sales of production, and various other information and technical data that were accepted as represented.

In reviewing the resource estimates contained in this report, it should be understood that there are inherent uncertainties in regards to limited available geological and engineering data (well histories and logs, seismic and other geophysical and exploratory technologies) and few direct producing analogs. The judgments used in assessing the resources are considered reasonable given the knowledge of the properties reviewed by Quantum.

A personal field examination of these properties was considered to be unnecessary because the data available from the operator records, South Oil, Laroco LLP, and public sources was satisfactory for our purposes. Quantum's knowledge of the leasehold positions is limited as to the extent and nature of ownership of the leases. All factual data submitted by the Datinvest and its representatives are believed to be true.

Respectfully Submitted,

Wesley E. Franklin

Wesley E. Franklin

Certified Petroleum Geologist AAPG (# 2388)
Registered Geologist, State of Washington (# 2093)
Quantum Oil & Gas, L.L.C.

II. DEFINITIONS, CLASSIFICATIONS, AND ESTIMATIONS of RESOURCES

Hydrocarbon Products*

Crude Oil: A mixture, consisting mainly of pentanes and heavier hydrocarbons that exist in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain sulfur and other non-hydrocarbon compounds, but does not include liquids obtained from the processing of natural gas. Classes of crude oil are often reported on the basis of API gravity. Acceptable ranges are as follow:

- Light: (greater than 31.1º API)
- Medium: (31.1º API to 22.3º API)
- Heavy: (22.3º API to 10º API)
- Extra-heavy: (less than 10º API)

Natural Gas: A mixture of lighter hydrocarbons that exist either in the gaseous phase or in solution in crude oil in reservoirs but are gaseous at atmospheric conditions. Natural gas may contain sulfur or other non-hydrocarbon compounds.

Natural Gas Liquids: Those hydrocarbon components that can be recovered from natural gas as liquids, including but not limited to, ethane, propane, butane, pentane plus, condensate and small quantities of non-hydrocarbons.

*(Section 5 of Volume 1 of the Canadian Oil and Gas Evaluation Handbook, by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy and Petroleum (Petroleum Society), June 30, 2002.)

Definitions and Classifications of Reserves and Resource

Any estimation of resources or reserves for hydrocarbon accumulations is subject to both technical and economic uncertainties, and should be quoted as a range. The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty.

In consideration of reserves categories, proved, probable, and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The range of uncertainty is reflected in estimates for proved reserves (conservative), proved + probable reserves (realistic), and proved + probable + possible reserves (optimistic).

For resources, low estimate, best estimate, and high estimate categories are understood, but as La Rosa is an established producing field, this resource classification is not used in this report. The estimates of reserves and resources are mutually exclusive and must not be aggregated. For the purpose of information and clarity of classification, the following two categories are defined for this report.
Contingent resources are defined as those quantities of oil and gas estimated on a given date to be potentially recoverable from known accumulations, but are not currently economic. Contingent resources include, for example, accumulations for which there is currently no viable market.

Prospective resources are defined as undiscovered but recoverable quantities of oil and gas estimated on a given date to be contained in hydrocarbon accumulations.

RESERVES:

Reserves are quantities of oil and gas anticipated to be economically recoverable from discovered resources. The definition of economic for an accumulation will vary according to local conditions of prices, costs, and operating circumstances and is left to the discretion of the company concerned, but reserves must be classified according to the definitions of the COGE Handbook. Hydrocarbons must not be classified as reserves unless there is an expectation that the accumulation will be developed and placed on production within a reasonable timeframe.

The determination of oil and gas reserves involves estimates that have an inherent degree of uncertainty. Categories of proved, probable, and possible reserves have been established to reflect the level of these uncertainties and indicate the probability of recovery.

The estimation and classification of reserves requires professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied.

a. Proved Reserves

Proved reserves can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves (conservative case).

- It is expected that there is at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves

b. Probable Reserves

Probable reserves are additional reserves that are less certain to be recovered than proved reserves. It is likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved + probable reserves (realistic case).

- It is expected that there is at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved + probable reserves;

c. Possible Reserves

Possible reserves are additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved + probable + possible reserves (optimistic case).

- It is expected there is at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved + probable + possible reserves.

.

Proved Reserves

Proved Developed Producing Reserves (PDP)

Proved Developed Producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Proved Developed Non-Producing Reserves (PDNP)

Proved Developed Non-Producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

Proved Undeveloped Reserves (PUD)

Proved Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

In multi-well pools, total pool reserves may be allocated between the developed and undeveloped categories, or to subdivide the developed reserves for the pool between developed producing and developed non-producing.

The reserves estimates in this report have been prepared using the deterministic method. The deterministic approach is the most commonly used reserve assessment method worldwide, and it involves the selection of a single value for each parameter in the reserves calculation. The discrete value for each parameter is selected based on historic production volumes produced from a field, and the estimator's experience with reservoir and field patterns, characteristics and behavior to determine placement of the reserves in the most appropriate reserves category.

Aggregation of Reserves Estimates:

Reported Reserves typically comprise the aggregate of estimates prepared for a number of individual wells, reservoirs, and/or properties/fields.

When deterministic methods are used, *Reported Reserves* will be the simple arithmetic sum of all estimates within each reserves category. Evaluators and users of reserves information must understand the effect of summation on the probabilities of estimates. *The probability associated with the arithmetic sum for a number of individual estimates is different from that of each of the individual estimates*. Arithmetic summation of independent high probability estimates will result in a total with a higher probability; arithmetic summation of low probability estimates will yield a total with a lower probability.

As the definitions and guidelines require a conservative approach in the estimation of proved reserves, the minimum probability target for proved *Reported Reserves* will be satisfied with a deterministic approach as long as there are enough independent entity estimates in the aggregate. Since proved + probable reserves

prepared by deterministic methods will approximate mean values, the probability associated with the estimates will essentially be unaffected by aggregation.

General Requirements for Classification of Reserves

The following general conditions must be satisfied in the estimation and classification of reserves.

a. Drilling Requirements

Proved, probable, or possible reserves may be assigned only to known accumulations that have been penetrated by a well bore. Potential hydrocarbon accumulations that have not been penetrated by a well bore may be classified as prospective resources.

b. Testing Requirements

Confirmation of commercial productivity of an accumulation by *production* or a *formation test* is required for classification of reserves as proved. In the *absence* of production or formation testing, probable and/or possible reserves are assigned to a zone on the basis of well logs and/or core analysis that indicate that the zone is hydrocarbon bearing and is analogous to other reservoirs in the immediate area that have demonstrated commercial productivity by actual production or formation testing.

c. Economic Requirements

Proved, probable, or possible reserves are assigned only to those volumes that are economically recoverable. The fiscal conditions under which the reserves estimates are prepared are where a reasonable outlook can be made of the future and for this reason; constant prices and costs have been used.

d. Methodology

Standard methods were used in the analysis of uncertainty. These representations were prepared based on known data, analogy and other standard estimation methods including experience

Volumetric methods were used to calculate the reservoir rock volume, the hydrocarbons in place, and the degree of hydrocarbon recoverable from the original hydrocarbons in place. The key unknown factors in volumetric reserve determinations are rock volume, effective porosity, fluid saturation and recovery factor.

Rock volume is determined as the product of a single well drainage area and net pay and geologic mapping. Geological characteristics, reservoir fluid properties and drainage areas, potential pressure depletion and potential boundary conditions from test data were incorporated in the estimates

Where data that clearly defines fluid contacts, the structural interval for Volumetric calculation of proved reserves was restricted by the lowest known structural elevation of occurrence of hydrocarbons as defined by well logs, core analyses, formation testing and previous producing wells.

Effective porosity, fluid saturation and other reservoirs were determined from logs, core, well test data and previous production.

Recovery factors were determined using rock and fluid properties, hydrocarbons in place, drilling density, drainage area, depletion and economic factors.

Prospect Technical Evaluation Stage

A prospect can often be subcategorized based on its current stage of technical evaluation. The different stages of technical evaluation relate to the amount of geologic, geophysical, engineering, and petrophysical data, as well as the quality of available data. In this report, prospects are referred to as mature prospects to reflect the current stage of technical evaluation.

Mature Prospects - A mature prospect is a potential accumulation that is sufficiently well defined to be a viable drilling target. For a mature prospect, sufficient data and analyses exist to identify and quantify the technical uncertainties, determine reasonable ranges of geologic chance factors, engineering and petrophysical parameters, and estimate prospective resources.

Immature Prospect - An immature prospect is less well defined and requires additional data and/or evaluation to be classified as a mature prospect. An example would be a structure mapped using regional seismic data in a basin containing favorable source and reservoir(s). An immature prospect may or may not be elevated to mature prospect status depending on the results of additional technical work.

Present Worth

The potential values of the projected resources are expressed in terms of present worth, which is defined as potential future net revenue discounted at a specified discount rate compounded monthly over the expected life of the project. In this report, present worth values are summarized using the estimated 10% discount rate (although discounted net cash-flows are included in the economic summaries at rates from 5% to 25%).

Potential $PW_{10\%}$ estimates are provided as a means of comparison to the potential present worth estimates of other resources, and do not provide a means of direct comparison to the present worth estimates attributable to reserves.

Estimates of reserves and their potential present worth should be regarded only as estimates that may change as additional information becomes available. Not only are such reserves and potential present worth estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in judgmental factors in interpreting such information. The volumes that might actually be recovered may differ from the estimates presented in this report.

Estimation of Reserves

Estimates of reserves were prepared by the use of standard geological and engineering methods generally accepted by the petroleum industry. The methods used in the analyses of the reserves were tempered by experience with similar reservoirs, the stage of development of the prospects, and the quality and completeness of the data.

The analysis of the reserves in this report considered the uncertainty in the amount of petroleum that may be discovered, and the geologic risk factors. The uncertainty analyses addressed the range of possibilities for the general parameters that determine the size of the resources and the geologic risk analysis addresses the probability that the identified prospects will encounter petroleum that flows at a measurable rate.

III. Datinvest Exploitation Program

Datinvest is in the process of acquiring a *81.25%* working interest (W.I.) bearing 64.8% net revenue (N.R.I.) in producing leasehold interests in the La Rosa field, Refugio County, Texas, represented to be approximately 3,800 acres (HBP) of developed and undeveloped acres gross to the Company. Value of the land alone is estimated to be $1,500,000 and value of 23 square miles of 3-D seismic is estimated to be $800,000. The field has 8 producing wells, surface facilities (including compressor and salt water disposal facilities) and pipelines.

The complete working interest in the La Rosa Field is currently held by Laroco LLP and Fortune Energy. No critical land considerations exist on the 3,800 acres held by production, but unleased prospects have been defined to the north and west outside the subject land position.

To evaluate the resource potential of the assets, Datinvest is continuing to evaluate existing 3-D, purchase neighboring available 3-D datasets, reprocessing all 3-D utilizing pre-stack depth migration (PSDM) and evaluating other seismic attribute and special analyses.

The list of anticipated drilling wells is noted in the Economics and Prospects segment of this report. |

The net cash flow, discounted (10%) and undiscounted, is calculated based on anticipated hydrocarbon recoveries, royalties, adjusted current prices, drilling and operating expenses, and ad valorem taxes, before income tax (BFIT). All cash flow data is in U. S. dollars. A summary of the Datinvest's net share of reserves and net share of the future production and incomes is in Section V.

Crude Oil and Natural Gas Prices

Any reference in this report to the equivalency of the price or value between oil and gas is defined by section 5.14(d) of NI-51-101. Written disclosure includes information expressed in BOEs, MCFGEs or other units of equivalency between oil and gas: (d) the disclosure shall include a cautionary statement to the effect that:

"BOEs [or 'MCFGEs' or other applicable units of equivalency] may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 MCF: 1 bb1 [or 'An MCFGE conversion ratio of 1 bb1: 6 MCF] is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead".

Oil and gas prices (as well as costs) respond daily to the vagaries of the futures markets, and therefore are subject to the numerous influences affecting supply and demand. In our experience, prices respond to many unpredictable economic, political, social, emotional and climatic factors, and the range of variables are so great that the industry has seldom been able to successfully predict resource prices into the future. The information affecting economic projections are just models, though based on experience, analogy and professional technical knowledge. The basis for estimating production rates and resource, or reserve, estimates, have many inherent uncertainties, which affect revenues, taxes, expenses and cash flows. Pricing is a significant factor in these outcomes, and it is important to not introduce additional uncertainty and volatility into the economic models by indicating that the knowledgeable estimator knows what the price fluctuations are to be over the life of the project. For these reasons, we have elected to choose a reasonable approach to pricing, using two separate methods for developing the economic scenarios. One method is a "flat price projection" which holds prices constant over the life of each project (using the price at the date of this report…May 21, 2007) at $64.20 per barrel of oil and $7.20 per MCF natural gas.

The other method is to use a “forecast pricing projection” which employs the U.S. Department of Energy Projected Crude Oil and Natural Gas Average Prices to vary oil and gas price forecasts over the history of the economic evaluations of this project.

-END- MO-YR	NET OIL PRICE $/MBO	NET GAS PRICE $/MCF
12-07	66.700	7.440
12-08	64.100	7.380
12-09	60.900	6.790
12-10	57.500	6.470
12-11	54.300	5.990
12-12	51.700	5.820
12-13	50.000	5.650
12-14	49.600	5.680
12-15	49.900	5.620
12-16	49.900	5.620
12-17	49.900	5.620
12-18	49.900	5.620
12-19	49.900	5.620
12-20	49.900	5.620
12-21	49.900	5.620
(Avg. Prices at End 15 Years)	54.339	6.070
(Avg. Prices for remainder of the life of the Project)	49.900	5.620
(Avg. Prices over Total Life of the Project)	54.183	6.040

IV. CERTIFICATE AS QUALIFIED PERSON AND CONSENT OF AUTHOR

Wesley E. Franklin
3310 Louisiana, #2408
Houston, TX 77006
(713) 826-5828

CERTIFICATE AS QUALIFIED PERSON BY AUTHOR

I, **Wesley E. Franklin**, Certified Petroleum Geologist, do hereby certify that:

1. That I am a partner in Quantum Oil & Gas, LLC, Houston, Texas, which has been retained as a consulting firm to evaluate certain assets for Datinvest International Ltd. in South Texas, U.S.A.

2. That Quantum Oil & Gas, LLC's partners have no direct or indirect interests, nor do they expect to receive any direct or indirect interest, in the properties, or in any securities of Datinvest International Ltd.

3. I am a Certified Petroleum Geologist with the Association of Petroleum Geologists (AAPG) (# 2388) and a Registered Geologist, State of Washington (#2093).

4. I graduated with a B.S. degree in Geology from Washington State University in 1969 and an M.S. degree in Geology from Oregon State University in 1975.

5. I am a member of the American Association of Petroleum Geologists (AAPG), Geological Society of America (GSA), Society of Petroleum Engineers (SPE), Society of Exploration Geophysicists (SEG), Houston Geological Society and Houston Geophysical Society. As stated in (1.), I am a Certified Petroleum Geologist with the AAPG and a Registered Professional Geologist with the State of Washington.

6. I have worked as a professional geologist for a total of 36 years since my graduation from university. I am responsible for the preparation of the report entitled **EVALUATION OF ASSETS: La Rosa Field, Refugio County, Texas** (Technical Report) which estimates the expected value reserves and present worth cash-flows for Datinvest International Ltd., south Texas production and prospects.

7. A personal field examination of these properties has been made of the properties and a review of all available well data, engineering and production data, 3-D seismic data, and Laroco's production and revenue records. In addition, considerable research and familiarization of the geology and engineering in the region has been performed by Quantum.

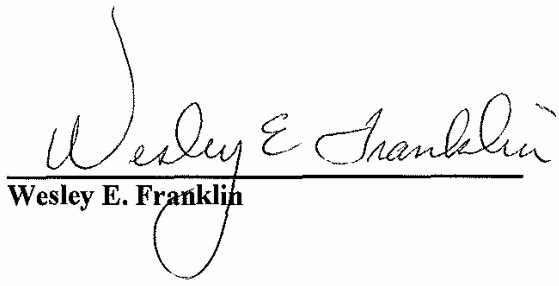
8. I have had prior involvement with exploration and development in South Texas from 1988 to 1097 as Division Manager, for Fina Oil and Chemical Company's South Texas Division, and as Fina's General Manager for North American Exploration. Subsequently, I am part owner (as well as Quantum partner Chris Barden) are part owners in a 700 acre producing property in the Mission River field several miles

to the northeast which produces from equivalent geologic reservoirs to La Rosa, and we (with Quantum partner Tom Bowmen) have evaluated the 3-D data on the Rooke Ranch to the immediate west of the La Rosa Field. We personally have a well log dataset that includes every well drilled in Refugio County. An engineer that helped Quantum evaluate the field, Randall Salge, was assigned La Rosa field as his project with Amoco in 1973, and was Area Engineer, then Production Manager for Fina Oil and Chemical Company for 28 years, primarily bearing responsibilities over the Texas Coastal Region.

9. I am not aware of any material fact, or material change with respect to the subject matter of the Technical Report, that is not reflected in the Technical Report, the omission to disclose which makes the Technical Report misleading.

10. I am independent of the issuer, Datinvest International Ltd. I consent to the filing of the Technical Report with any stock exchange and other regulatory authority and any publication by them, including electronic publication in the public company files on their websites accessible by the public, of the Technical Report.

Dated this 21st day of May, 2007



Wesley E. Franklin

Certified Petroleum Geologist AAPG (# 2388)
Registered Geologist, State of Washington (# 2093)
Quantum Oil & Gas, L.L.C.

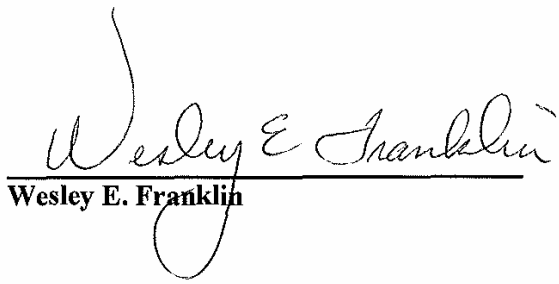
Wesley E. Franklin
3310 Louisiana, #2408
Houston, TX 77006
(713) 826-5828

CONSENT OF AUTHOR

I, Wesley E. Franklin, do hereby consent to the filing, with the TSX Venture Exchange, of the technical report **EVALUATION OF ASSETS: La Rosa Field, Refugio County, Texas** and dated May 21, 2007 (the "Technical Report") and to the written disclosure of the Technical Report and of extracts from or a summary of the Technical Report in the information circular of Datinvest International Ltd. dated May 21th, 2007 (the "Circular").

I also certify that I have read the Circular and I do not have any reason to believe that there are any misrepresentations in the Circular derived from the Technical Report or that the Circular contains any misrepresentation of the information contained in the Technical Report.

Dated this 21st day of May, 2007



Wesley E. Franklin

Certified Petroleum Geologist AAPG (# 2388)
Registered Geologist, State of Washington (# 2093)
Quantum Oil & Gas, L.L.C.

GEOLOGIC SETTING OF LA ROSA FIELD

LA ROSA FIELD SUMMARY

Introduction:

The La Rosa field is located 4 miles southwest of the town of Refugio. The field was discovered in September, 1938, following discoveries at Refugio (1920, 1928) and Tom O'Connor-Greta (1934) and was the result of geophysical work integrated with subsurface mapping, which indicated a large positive area south of the town of Woodsboro. There have been 151 gas and oil wells that produced from 44 separate Miocene and Oligocene Frio sands ranging in depth from 3,500'to 8,700'. Structurally, La Rosa is typical of gas and oil fields along a regional producing trend from Louisiana into Mexico, in that it is a large, low-relief roll-over anticlinal fold formed on the down-thrown and down-dip side of complex growth fault system referred to as the "Vicksburg Flexure". Most structural movement within the field occurred previous to the end of Frio deposition and little or no structure is observed in formations younger than the Frio. Some zones, like the 5,900' sand average about 32 % porosity, its permeability averages approximately 2,000 millidarcys, and ultimate recovery from this zone should be 975 barrels of oil per acre foot.

The Rock and Fluid properties from approximately 4,000 to 7,200 feet are as follow:

Reservoir	BTU	Gravity	% CO2	% N2	"4,000" Oil API°	"5,000-7,200" Oil API°	Cond. API°	Permeability	Porosity	Rec. Factor BO/AF	Net Pay
4,000-7,200 ft	1088.8	0.6098	0.1002	0.5081	23-37°	39-41°	45-50°	40-2,000 md	24-32%	500-975	5-50 ft

Reserves for the "shallow" reservoirs have been estimated by analogous from wells that have already produced from the respective reservoirs, and compared with volumetric calculations. Unfortunately, production from all oil wells on a lease in Texas pooled and not broken out individually, and production records in the state were not reported prior to 1970 (the field was discovered in 1938). Decline curves for oil wells are therefore by lease, and begin after 1970. Gas wells are reported on an individual well basis in Texas, but again, reserves are reported only after 1970, so many original formation pressures, and early production rates are not available. The 3-D seismic data at La Rosa is extremely valuable in assessing the volumetric analyses of the field reserve ranges. The 3-D seismic not only is valuable for mapping the aerial extent of each reservoir, but an estimate of the gross sand thickness can be estimated, and by comparison with producing wells, this permits a good estimate of net pay. When this data is compared with rock and fluid properties from the numerous producing wells in a given reservoir, a fairly accurate and reliable estimate of reserves can be made.

Deeper zones which represent much of the Probable and Possible reserves are expected to have a much higher gas-oil ratio and the characteristics of the rocks and the fluids will change from the conditions of the shallower rocks. Net pay for an individual reservoir is likely to be noticeably less, and porosity and permeability will be lower. API gravity is greater, and both pressures and temperatures will be higher. PVT analysis from a reservoir at 8,300' from McAlester Fuel Scanio-Shelton No. 6 at Mission River field just east of La Rosa is as follows:

Reservoir	BTU	Gravity	% CO2	% N2	% Methane	% Ethane	% Propane	Reserv Temp	Reserv Press	GOR	Cond. API°	Permeability	Porosity	Net Pay
8,000-9,000 ft	1151	0.6599	0.776	0.067	88.07	5.998	2.926	211°	4,161 psig	20,566	52.853	15-300 md	18-27%	2-15'

Because reservoirs deeper than 7,000 feet will likely be gas with associated condensate, decline curve analyses will be able to be more adequately performed, and this has been recognized in nearby producing wells, such as the well above. P/Z analyses indicate that pressure depletion is the predominant reservoir drive mechanism in these pressured gas-condensate reservoirs, but some wells do water out, indicating the presence of water drives. The 3-D seismic survey allows excellent mapping of the aerial extent of potential reservoirs, and the presence of hydrocarbon, but an estimation net pay thickness is not reliable. Therefore, estimation of net pay thickness and recovery factors are made from analogous producing reservoirs of comparable depths with rock and fluid conditions.

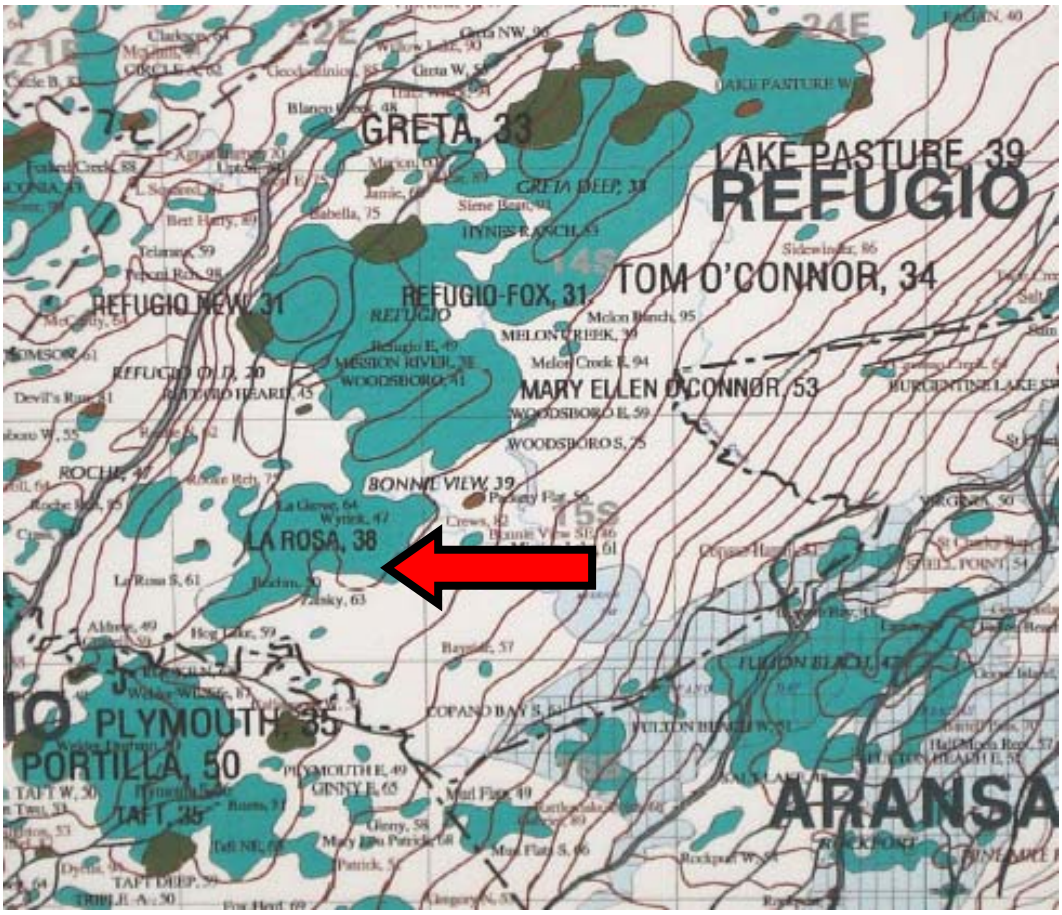


Figure 1, Location Map, La Rosa Field

Datinvest is purchasing the working interest of LAROCO LLP, which is 81.25% in the heart of the La Rosa Field. The field contains approximately 3800 acres held by production (HBP), which remain intact until all production within the field has ceased. Included in the sale are leases, 8 currently producing wells, behind pipe reserves, surface facilities, compressor, pipelines and some 30 locations delineated by 23 square miles of proprietary 3-D seismic data.

The field currently produces 700 MCFD and 70 BOPD from 8 wells, but an overhauled compressor has just been placed back on line, and when restored to full production, the field is anticipated to produce at rates approximating 1,000 MCFD and 100 BOPD. Remaining gross proved reserves are estimated to be 2.2 BCF and 504,000 BO.

Additional Potential Asset Value:

Leases:
Three year term lease in this area are approximately $400 per acre, although they probably are closer to $1,000 per acre adjacent to existing production. If the 3,800 HBP acres were newly leased today, the estimated land value would approximate $1.5 million.

Seismic:
A 23 square mile proprietary 3-D seismic survey would cost approximately $1.5 million; if acquired from a broker, the value would be approximately $800,000.

Prospects:
If the 24 identified probable and possible drilling locations (unrisked) are successful, an additional 1,947,000 BO and 36 BCF of gas could be realized. The unrisked and only partially deep Vicksburg sands with "bright spots" (10,000-14,000 feet) may add as much as 50 BCF to the field.

The company which owns the remaining 18.75% of the properties may be willing to sell its interests.

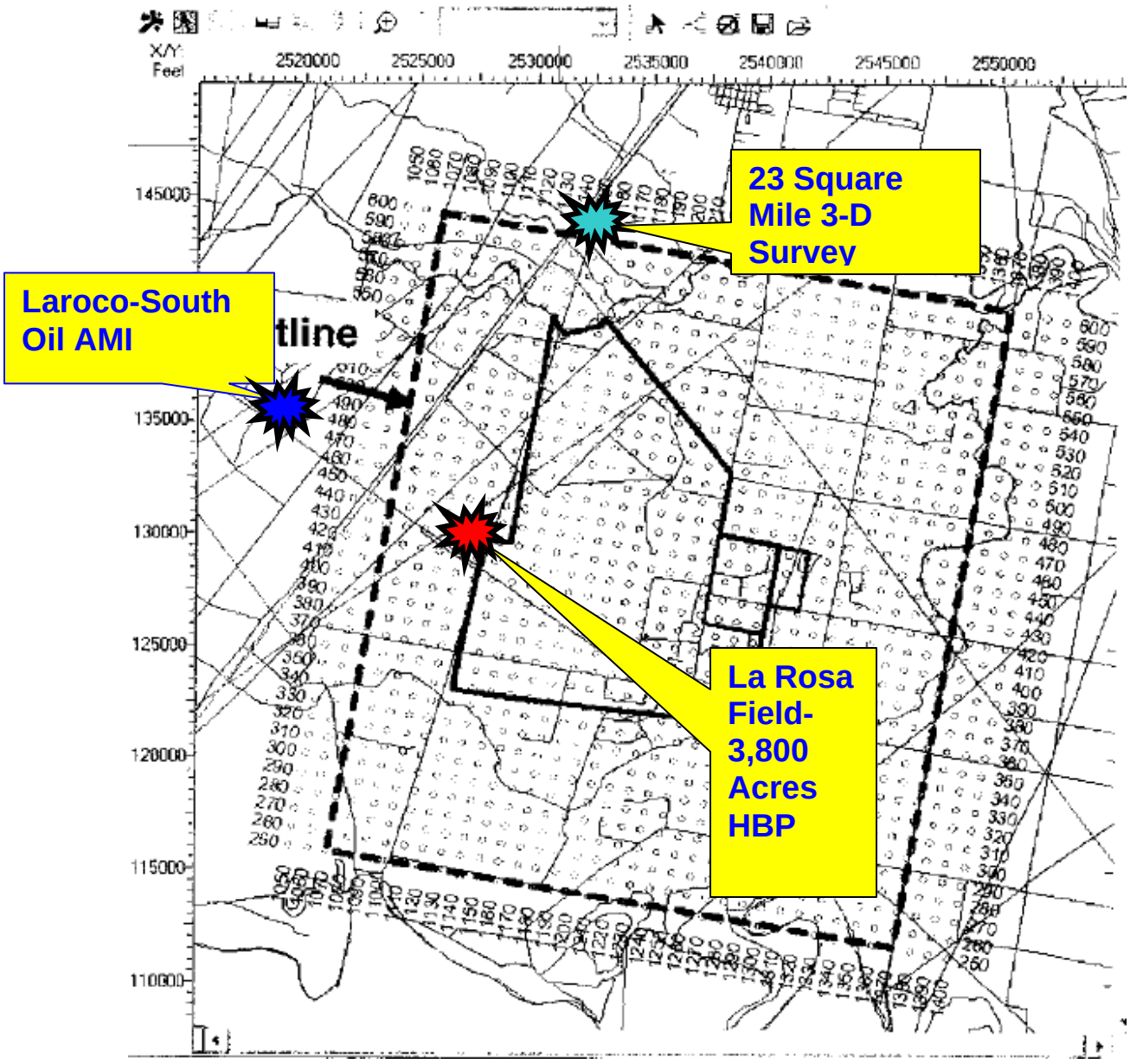


Figure 2, Outline of 3-D Survey (23 square miles). La Rosa properties in center.

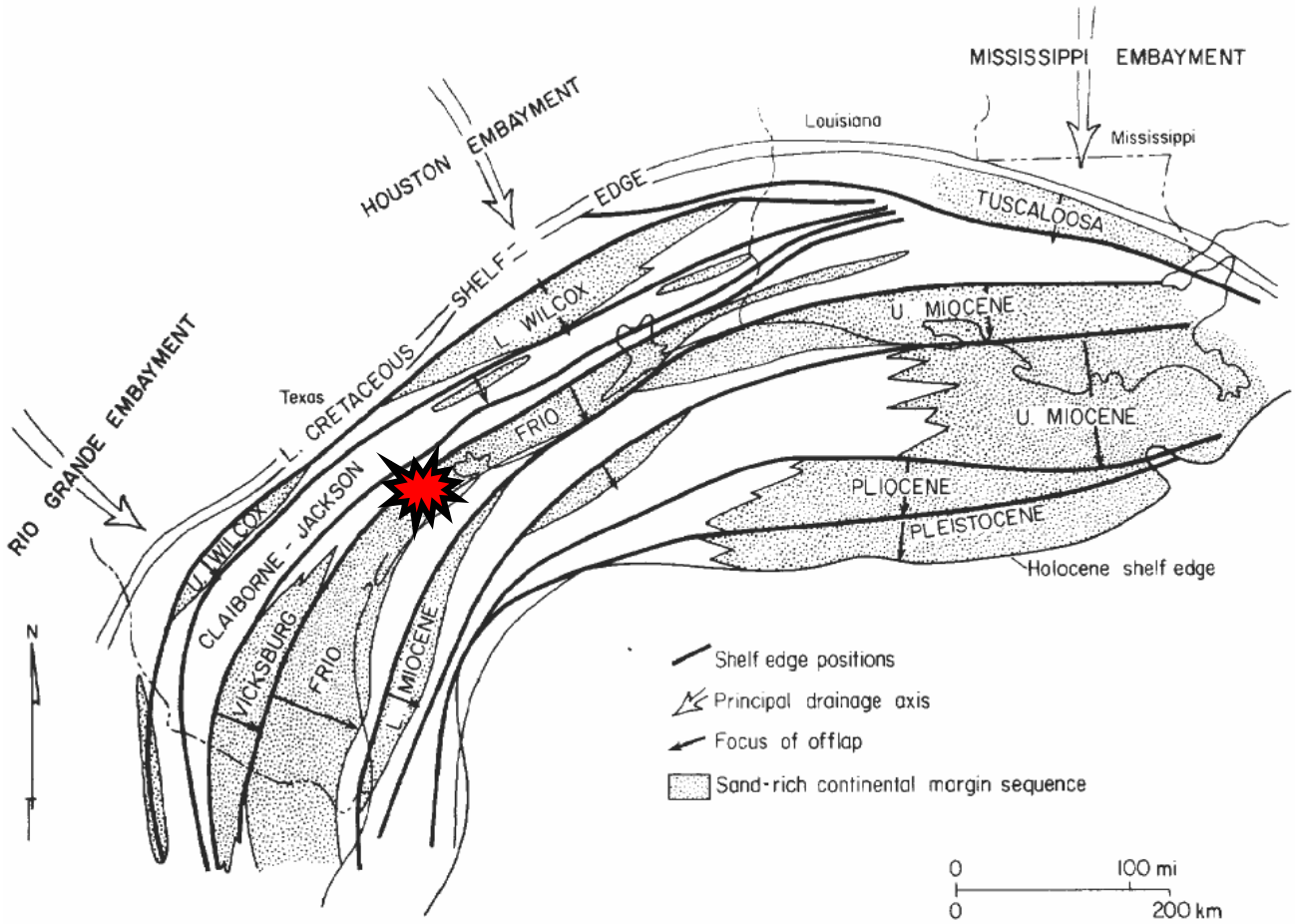


Figure 3, Arcuate shelf edge, growth fault trends of the Gulf Coast. The shelf moves progressively southward toward the center of the Gulf of Mexico as it with each successively younger system of sedimentation. Frio Fields shown on map below, red box around the La Rosa area.

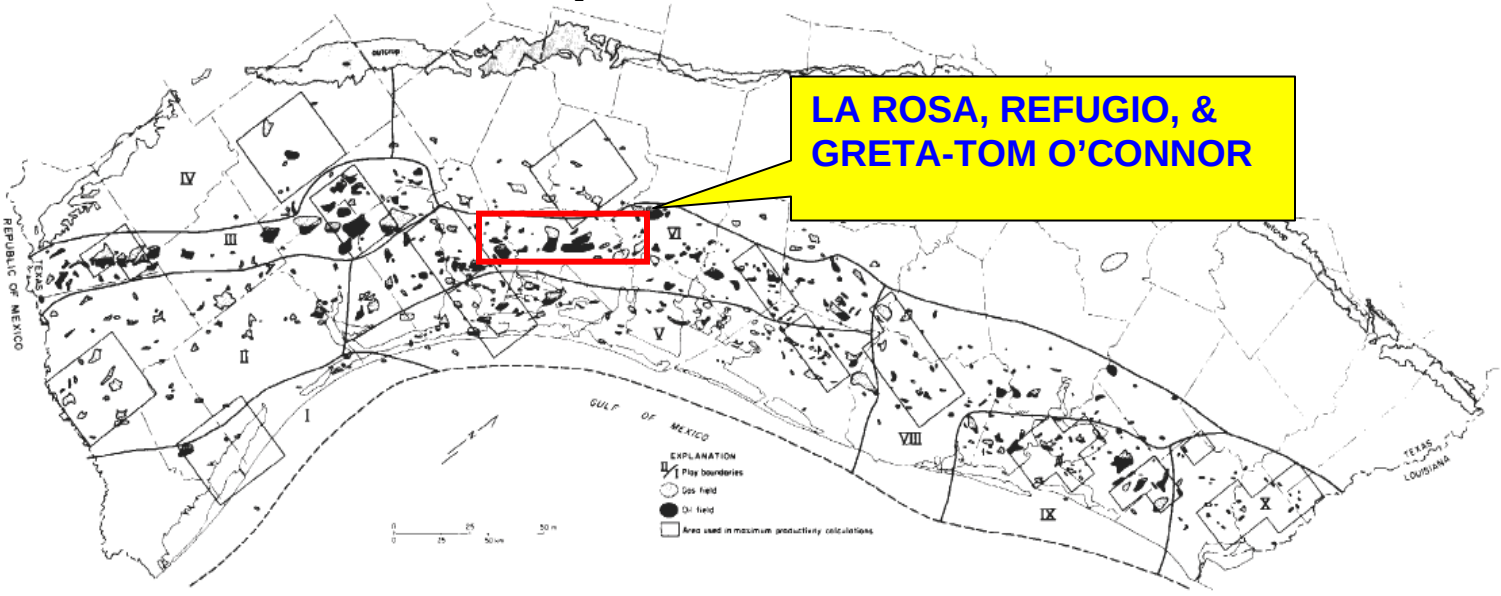


Figure 4, Frio Fields of Texas Gulf Coast. Red Box shows La Rosa Area.

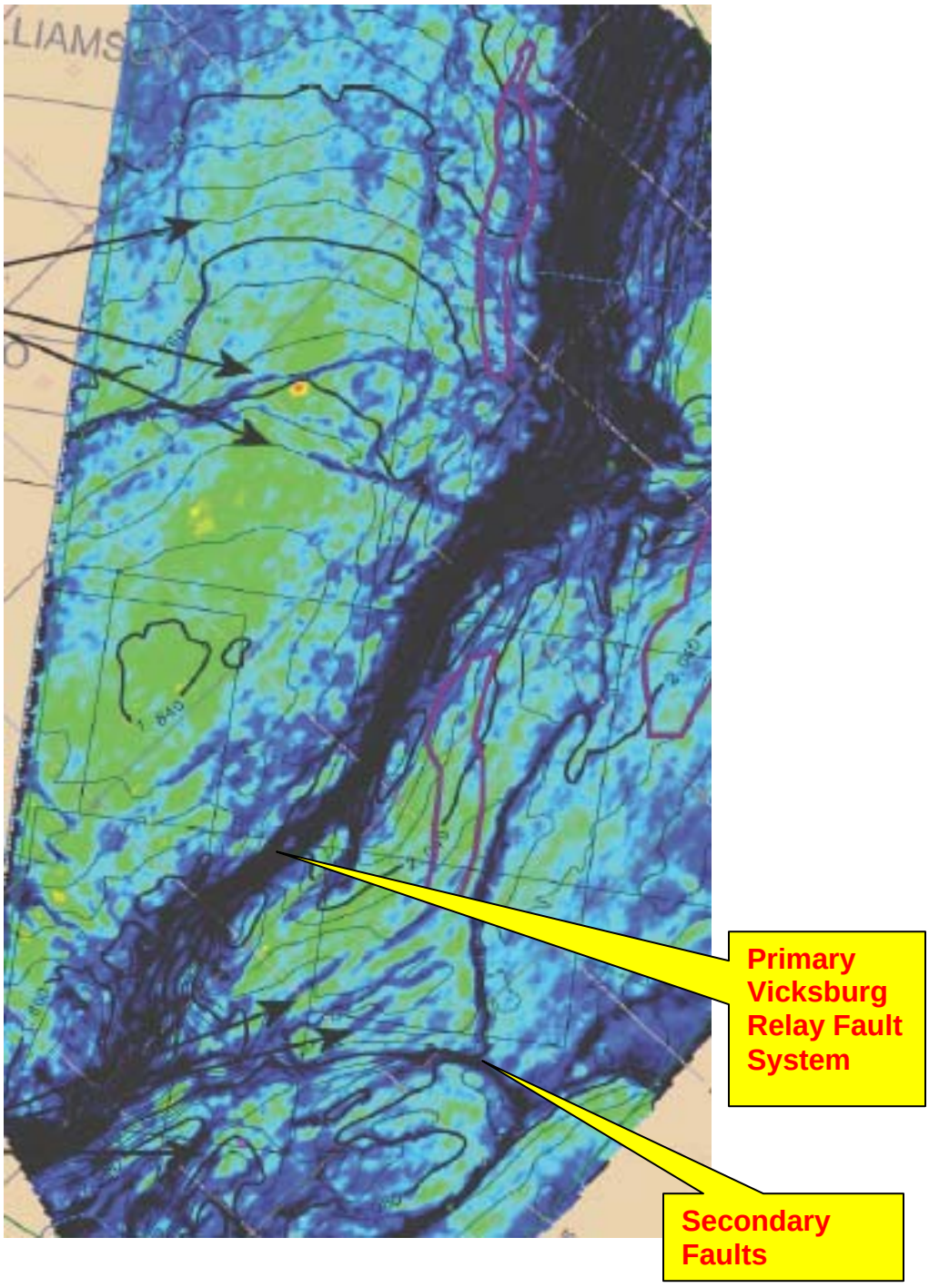
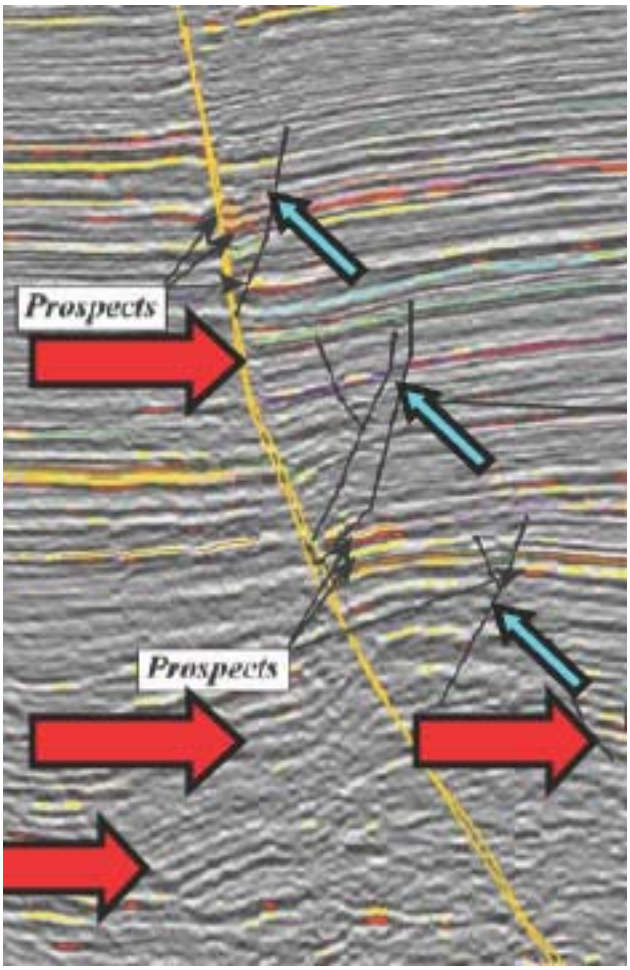
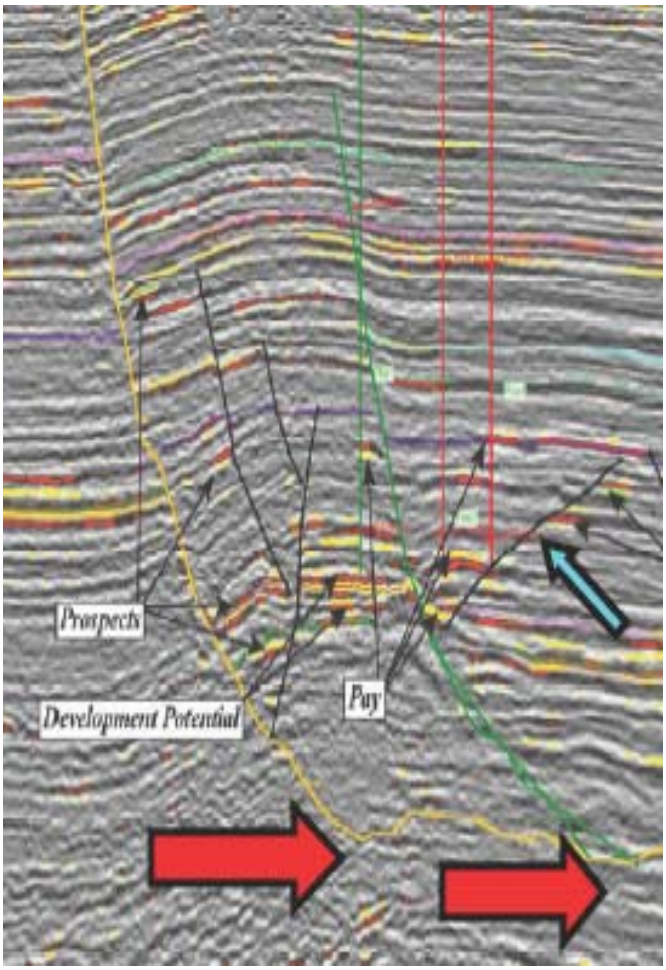


Figure 5, Seismic amplitude and time map shows the distinctive relay, or transfer fault, characteristics of the main Vicksburg growth fault system north of La Rosa (red spot) and west of Refugio field (yellow spot). Two following dip oriented seismic lines display the en echelon down-thrown character of the growth faults, as well as antithetic faults that are resultant from extension at the ancestral shelf margin.





Figures 6 and 7, East-west and north-south lines showing down to basin growth faults (red arrows) and antithetic faults and splays (blue arrows). Both structural environments are capable of trapping hydrocarbons (yellow bright spots indicate gas).

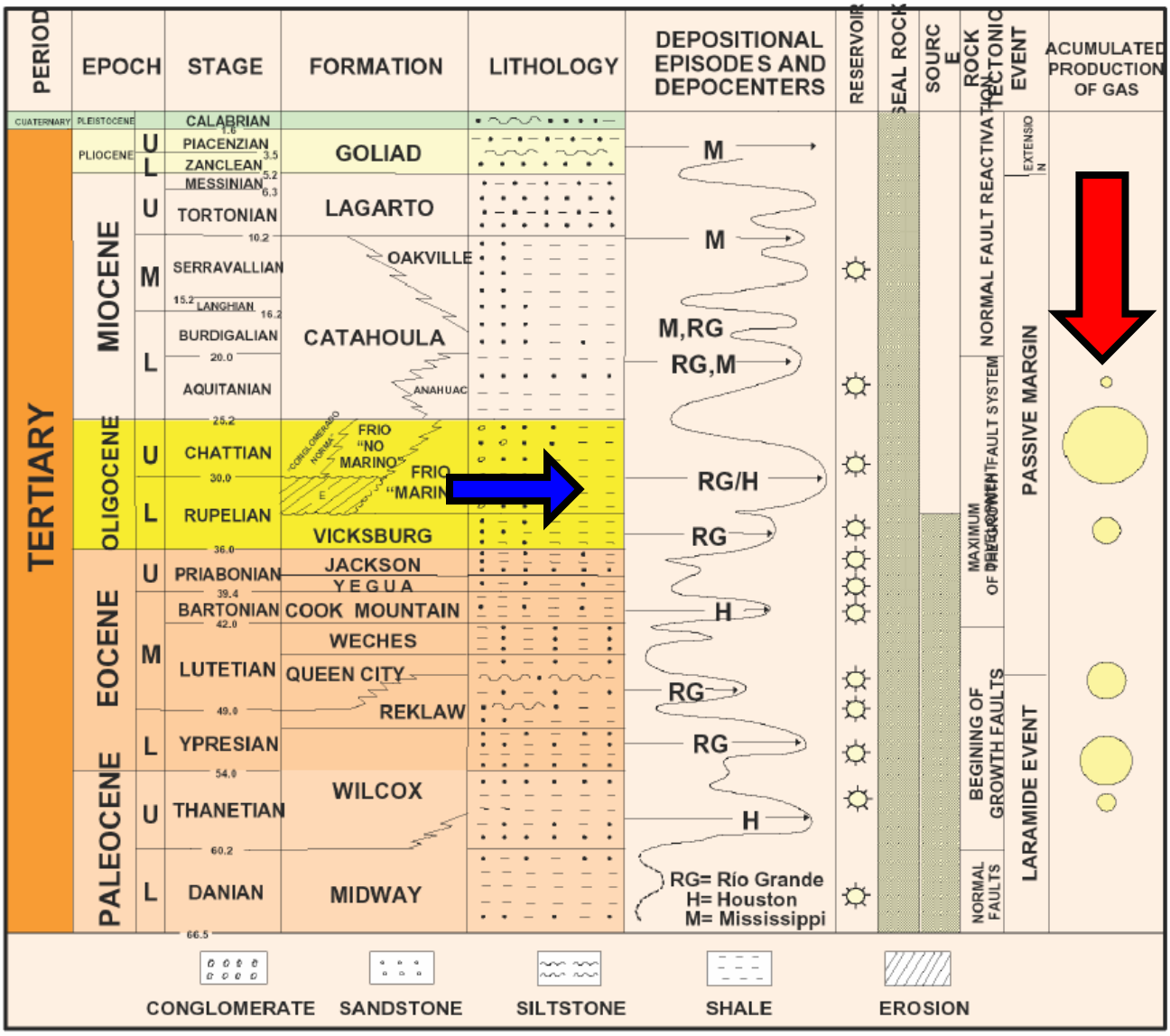


Figure 8, Stratigraphic chart for the Gulf Coast Tertiary sediments. Frio and Vicksburg are colored yellow and indicated with the blue arrow. The relative size of the hydrocarbon occurrence for the different formations is shown in right hand column; red arrow indicates Frio and Vicksburg.

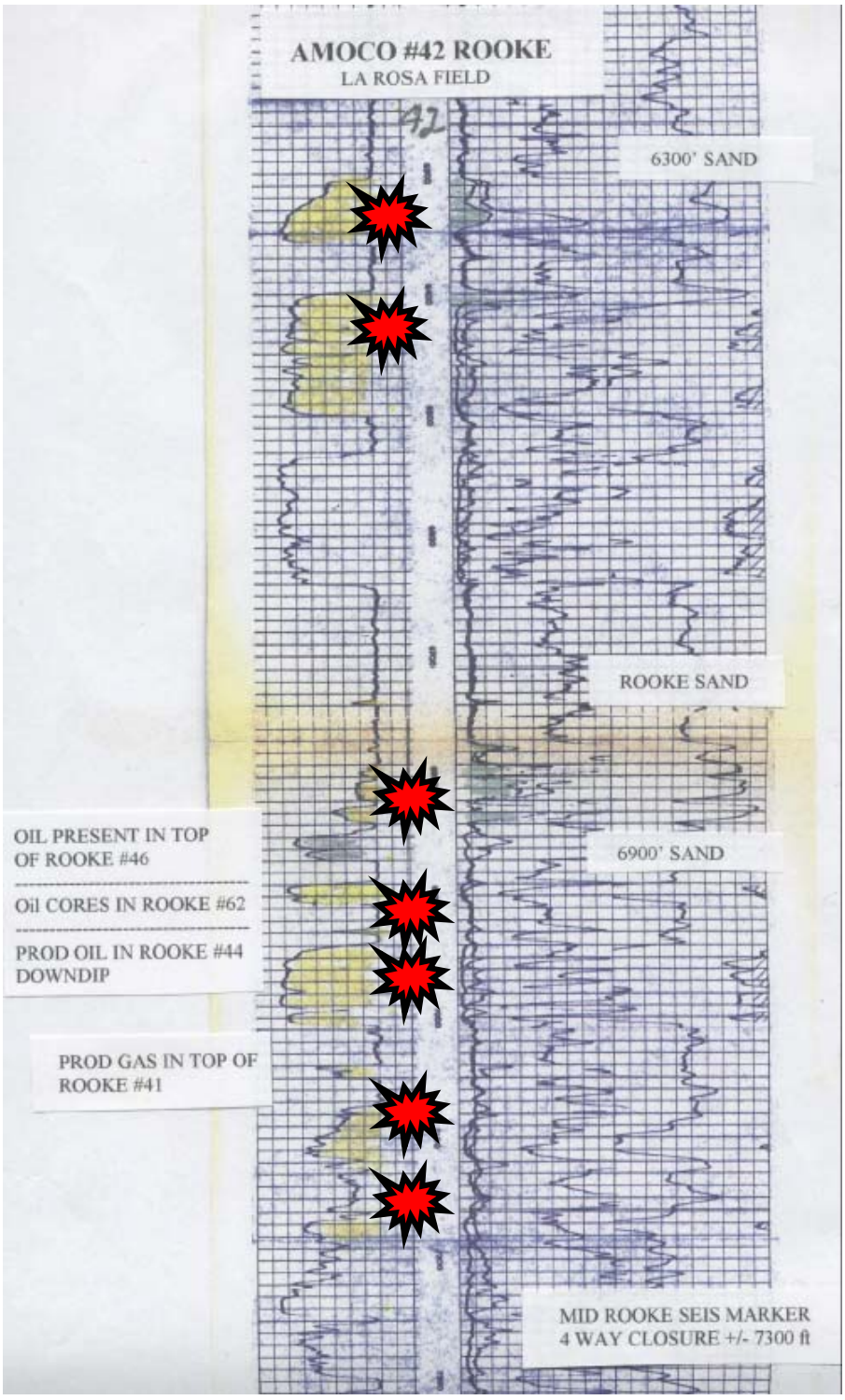


Figure 9, Amoco Rooke #42, the "type" electric log for a number of proposed locations. Some of the important field producers (6,300', the 6,900' sand and the Rooke Sand) are shown on log segment. The 6,300' sand is also known as the Tom O'Connor Sand.

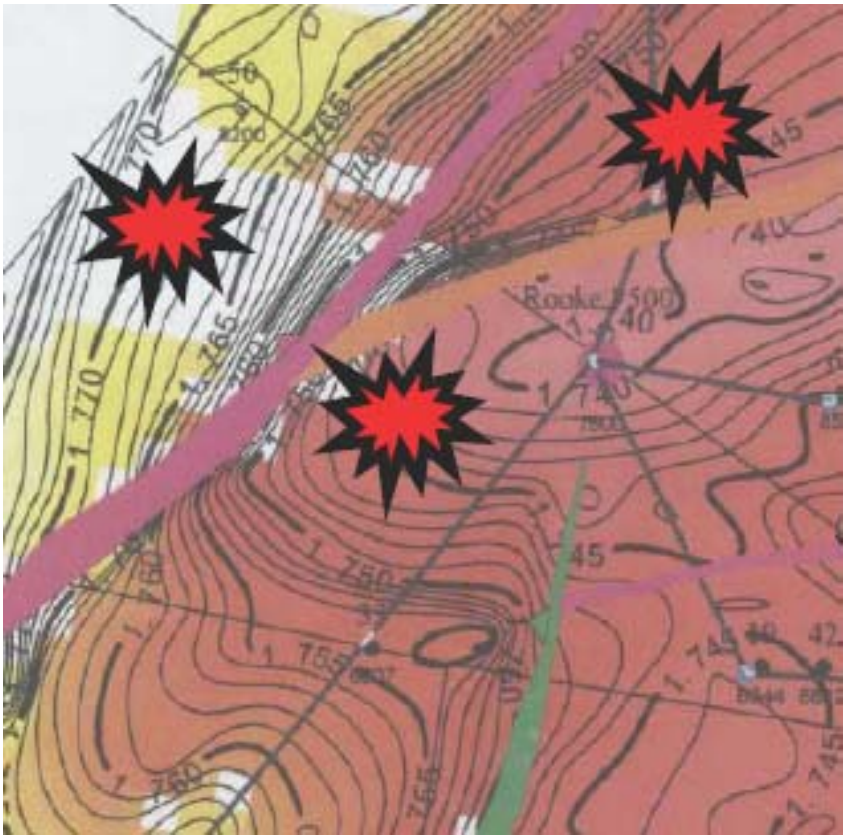


Figure 10, Seismic time structure map at Rooke Sand level on seismic line below (approximately 6,900'). Red Spots indicate infill prospects.

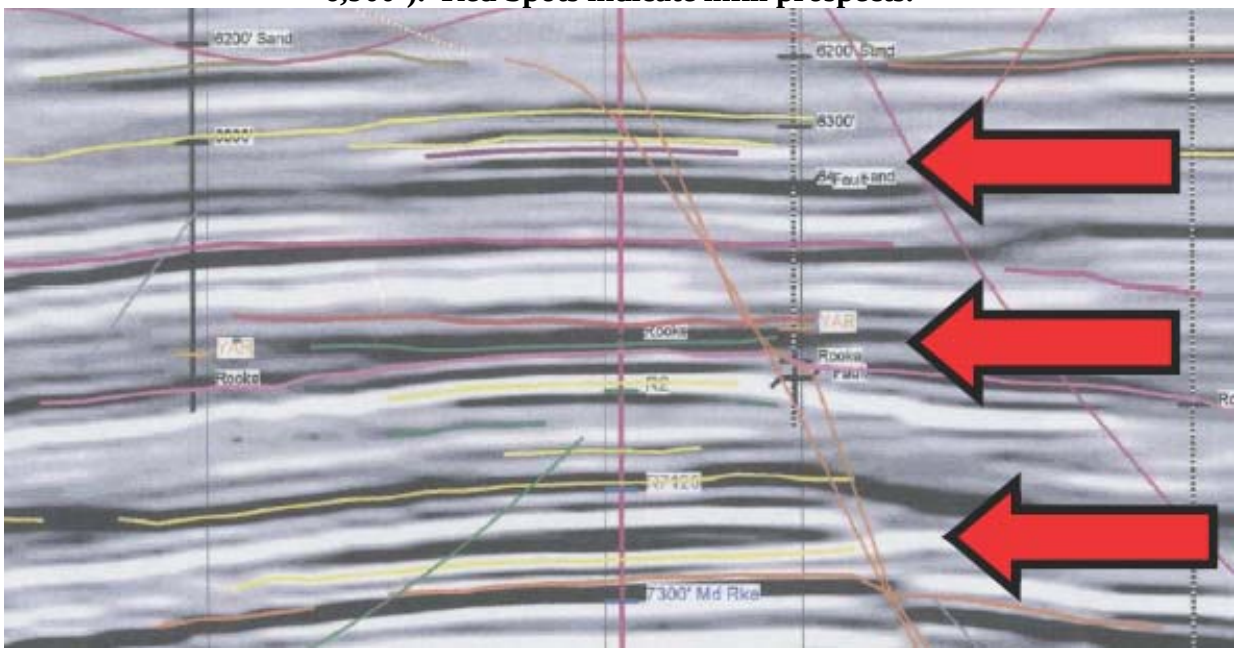
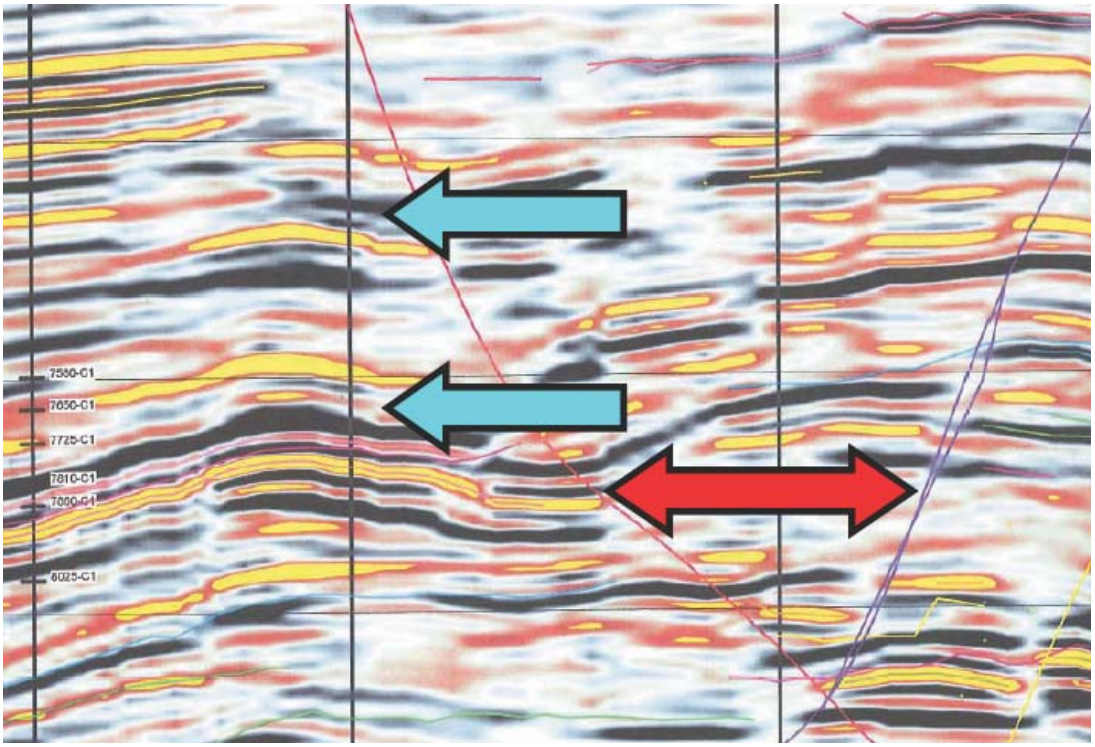
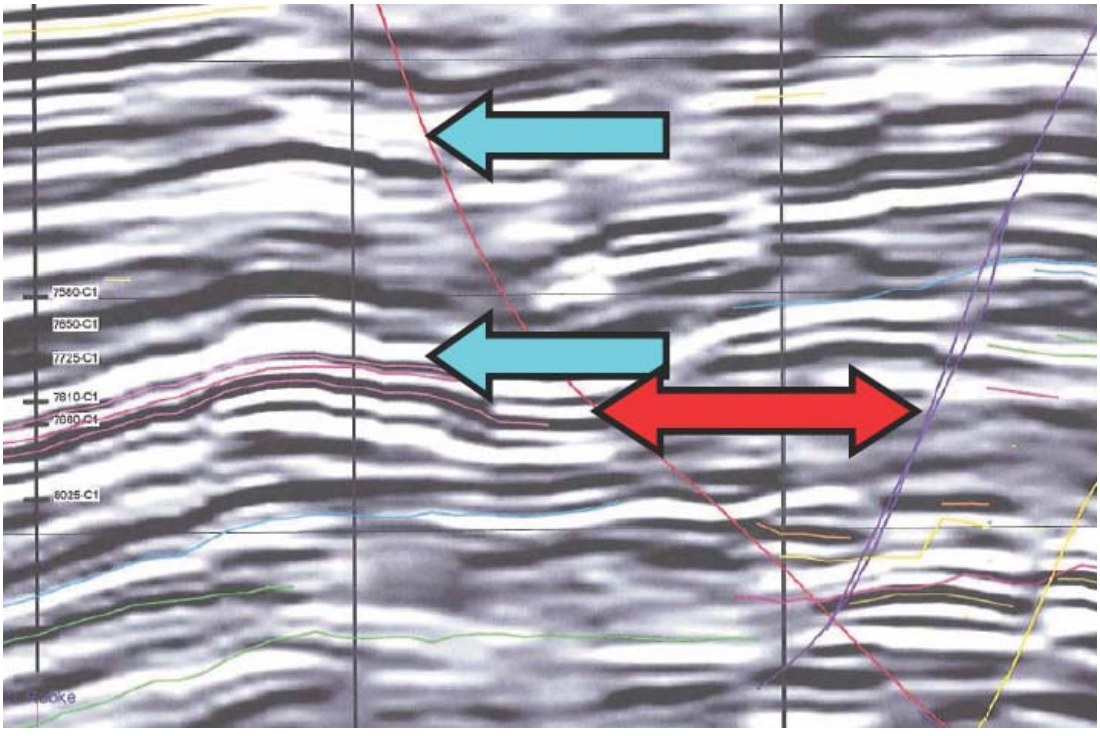


Figure 11, North-south oriented seismic line. Faults are parallel to main Vicksburg fault zone. "Bright spots" are indicated by red arrows.





Figures 12, 13, Northwest-southeast seismic line crosses structure (turquoise arrows). Red arrows show trapping faults.

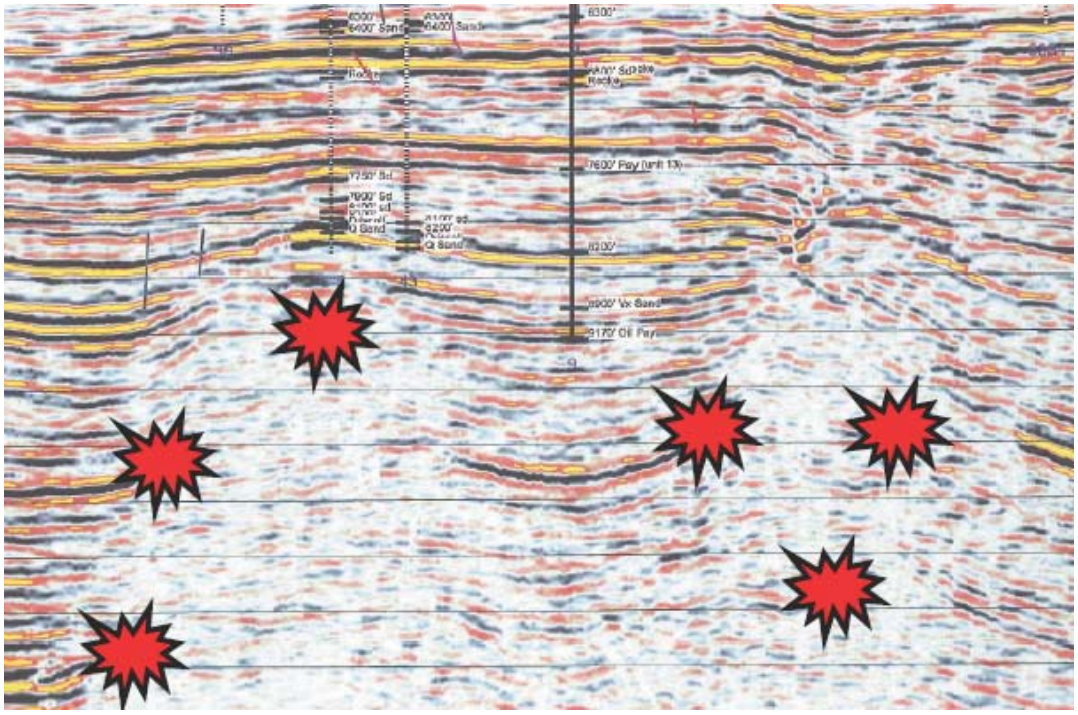


Figure 14, Diagonal NE-SW direction crossing the structure at crestal position

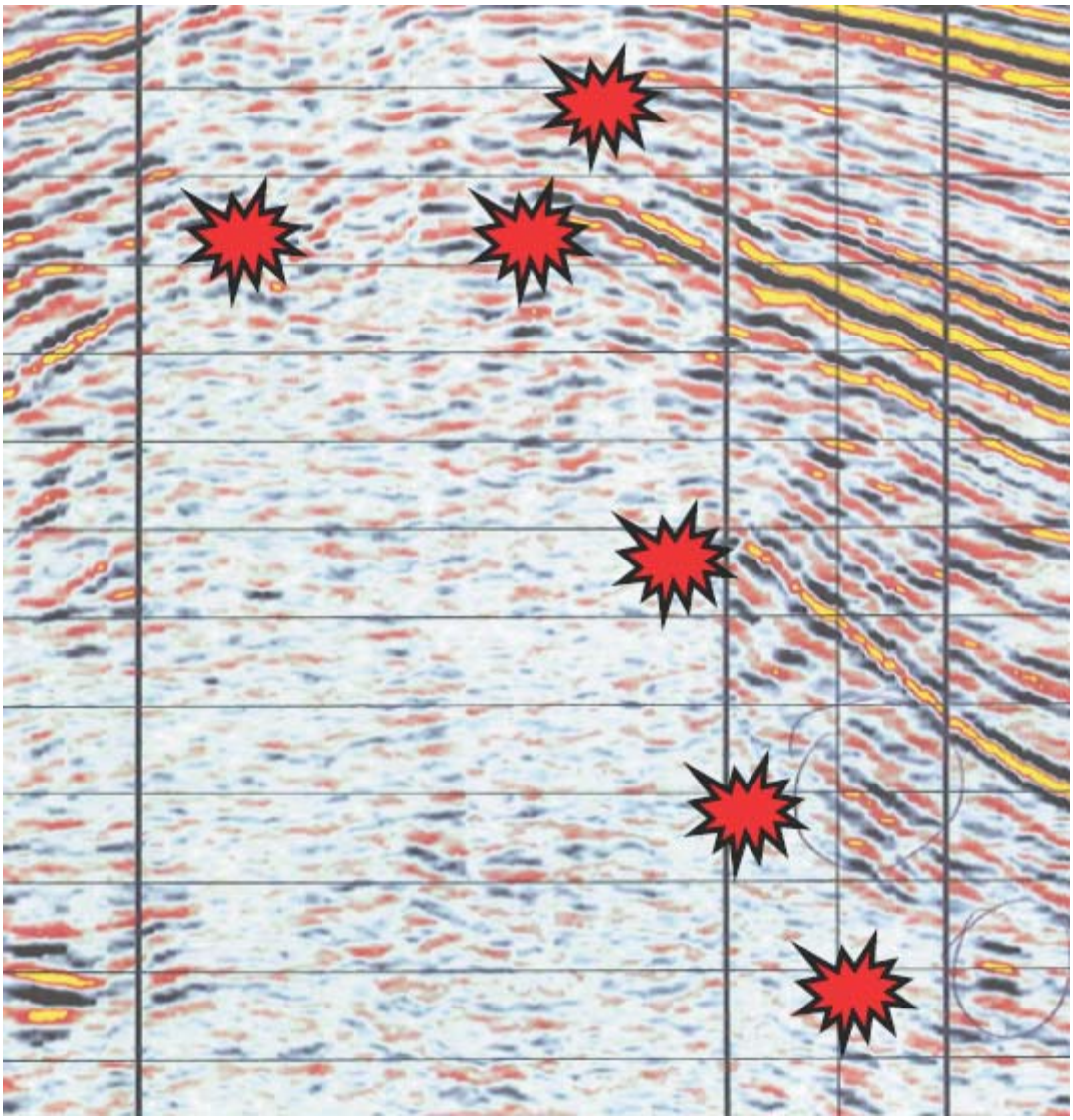
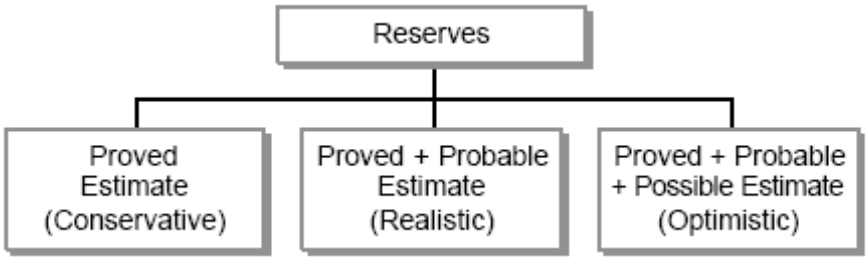


Figure 15, bright spots off the right flanks of Vicksburg structure and shale diapir; amplitudes are approximately 13,000 ft.

VI. PROSPECTS, ECONOMICS, AND RISK

The classifications and definitions of Reserves have been addressed in II of this report. For illustration purposes, the diagram below if from the COGE Handbook, and it figuratively depicts the categories that are used in this report.



Economics

Disclosures Concerning Production and Prospects

La Rosa is not an exploratory project, although it has exploratory potential. Therefore it is not practical to assess the geologic risks of each individual development prospect, for PUD or Probable prospect has a main primary objective, and numerous secondary objectives, which have produced elsewhere in the field. Each primary and secondary objective will differ from the next, having variable rock and fluid characteristics (pay thickness, aerial extent, recovery efficiency, porosity, permeability, degree of pressure and reserve depletion, water vs. depletion drives, API° gravity, gas-oil ratio, and, in deeper reservoirs, retrograde condensate factors related to dew point. Because of the multiplicity of objectives for development drilling, the risk of a dry hole is almost non-existent, but the risk of reservoir presence, quality and depletion of a discrete zone may exist, and in cases, may be substantial. Therefore, the continued development, exploitation and exploration within the field and its confines are not without risk or uncertainty, particularly relative to whether a well may be commercial, even though it becomes productive. For a variety of geological reasons, drilling of prospects may not realize the anticipated outcomes (this could be positive, as well as negative). The assessment of the reserves and the inherent uncertainties that can not be envisioned in the future (that may entail unexpected production and depletion, price fluctuations, economic climates, etc.), are done to the best of the estimators technical abilities, experience, and familiarity with the available data. The evaluators have adhered to the definitions, terminology, procedures and categories set out in the guidelines for the NI 51-101 (section 5.3) and the COGE Handbook for reserves and resources (sections 5.4 and 5.5).

Economic scenarios were performed utilizing both flat price cases and NYMEX futures forecast cases for price input discussed in the segment on definitions (II). Cash flow, or net income, calculations were discounted at 10%, but are also disclosed at discount rates ranging from 8% to 100% in the lower right corner of each economic summary. The La Rosa field consists of several individual properties, some of which are unitized, and some of which are not, and the economic projections were estimated without special distinctions for well locations complicated by these situations.

The estimates of reserves and future net revenue for individual properties may not reflect the eventual outcomes of the drilling of each prospect. The capital and operating expense, and tax projections, as well as the reserve and the net present value cash flows outputs of these economic scenarios are estimates only and are not a fair

market value of the potential reserves. The investor must not rely upon these estimates and projections as market or book value assets.

(a) La Rosa is located approximately 4 miles southwest of the town of Refugio, Texas, and is adjacent to the Refugio-Woodsboro-Mission River fields. The basin within which the field is present is considered "the lower coast of Texas, onshore Gulf of Mexico".

(b) Datinvest International Ltd has approximately 81.35% Working Interest (W.I.) and 64.8% Net Revenue Interest (N.R.I.) of 3,800 acres that are held by production (HBP).

(c) The acreage will expire upon the date of last production within the field.

(d) The La Rosa field has 44 producing intervals that Lower Miocene and Oligocene Frio in age from 4,000 to 8,700 feet. Potential Oligocene Vicksburg reservoirs are estimated to be from 10,000 to 14,000 feet. Existing idle well bores are planned for various recompletions to shallow horizons. These activities will be accomplished after new wells have been drilled, thereby better defining the likely results of the plug-back recompletions.

(e) Datinvest will own the existing gathering and sales pipelines, surface facilities (including compressor), pump jacks, salt water disposal wells, 44 existing well bores (of which 8 are currently producing), and access to all roads and access to and from the leases. Datinvest will also own 23 square miles of 3-D seismic data that covers the field.

Eventual abandonment costs for all existing wells, future wells and all surface equipment (as well as the estimated salvage value) have been incorporated as inputs into the economic runs for this report. $7,000 abandonment costs per well have been used, and this cost is based on the current owners recent costs to plug and abandon old wells, as well as personal experience of Quantum's abandonment costs 2 miles to the east in the Mission River Field. Salvage costs are estimated at $7,000 per well based on the same sources of information.

Input to the economic programs were made between years 20 and 30, and do not affect the Present Net Worth of the cash flows. As the capital expense output of the economic summaries does not show past year 15, these costs are not visible on the economic summary sheets.

(f) The field produces oil in the 39-41° API range, but future production is expected to produce oils and condensates that will vary in API gravity range from 35-58º. Natural gas does and will vary from approximately 1100-1200 BTU), natural gas liquids will be especially important when produced from the anticipated gas reservoirs below 7,000 feet (see above tables).

(1) Existing marketing and transportation arrangements are in place;

(m) The operator is South Oil Inc.; the contract employees of South Oil have extensive geological, geophysical, engineering, marketing and transportation knowledge of the Gulf Coast region in general, and the immediate La Rosa area specifically.

(n) The geological, mechanical, engineering and economic risks and the probabilities of success anticipated for the prospects, while considerably low (probabilities of geological success for PUD locations are virtually 100%, and in excess of 80% for the extension prospects), geological and mechanical uncertainties and risks do exist (see first paragraph of Disclosures). Some of the shallow reservoirs that have a depletion drive may be substantially underpressured from past production and add a mechanical risk of lost circulation while drilling to even infill drilling prospects.

Deeper pool and seismically derived exploratory prospects have inherently more risk; in these cases the geological risks involve effective traps, top and side sealing shales and faults, the presence and quality of the reservoir conditions, and the timing of migration (or charge) into the fault, pinch out, shale out or diapiric shale traps. From 8,000 to 9,000 feet, the pressures are expected to exceed normal pressure (.4-.45 psi/ft) and it is expected that another string of casing or liner will be run to withstand the 12.5 ppg mud weight conditions. Below 9,000 feet, mud weights may range from 15 to 18 ppg, depending on the depth and percent of sand enveloped by highly overpressured shale. In these circumstances, the risks of mechanical difficulty or failure are significant. It is estimated that the deepest potential objectives have geological risks in the 20-30% range; economic and engineering risks for these high pressured reservoirs may lower the overall probability of success of drilling a successful and/or a commercial well significantly.

(o) The estimate of the reserves in this report, as discussed in the Definitions section, reflects the range of three values that reflect reasonable likelihood's (Proved Reserves, the low value being conservative), (Proved plus Probable Reserves, the middle value being the median and realistic), (Proved plus Probable plus Possible Reserves, the high value being optimistic).

(p) Summarized Capital Expenditure schedule net to the 81.25% working interest is as follows:

*In the first year, drilling capital will be $1,056,250 specifically targeting PUD locations.
*Year two will spend $6,825,000 drilling Probable prospect locations.
*Year three will spend $10,968,750 for Probable prospects
and $1,137,500 for Possible prospects (for a total of $12,106,250).
*In year four, $4,550,000 will be spent on drilling Possible drilling locations.
*In year seven, a recompletion of a PDNP case will cost $40,625.
*In year eleven, a recompletion of a PUD case will cost $40,625.

(q) After Tax Net Income *(SEE APPENDIX B)*

It is estimated that the company will face a reduction of net income at a rate of 20% annually. The estimate is derived from the application of 35% estimated tax rate. The tax is reduced in that operators may immediately utilize approximately 75% of drill costs (Intangible Drilling Costs, or IDC's) to shield income. The remaining drill costs (Tangible Drilling Costs of TDC's) are also depreciated based on the amount of production compared to the estimated remaining oil and gas reserves on a field by field basis. The actual tax rate will depend on production rates, existing corporate tax benefits, rate of drilling and other capital expenditures, and the rate of tax applied by the applicable jurisdictions.

The estimates in this report have been made by Wesley Franklin and Chris Barden, the professional valuators. This report may not be relied on as fact or as any understanding that the assets and prospects discussed in this report are without risk or uncertainties or unknowns.

The following economic summaries are for all categories of proved (Proved Producing, Proved Developed Non-Producing, Proved Undeveloped), Probable and Possibles reserves. A one-line summary for each category, and each projected well in each category is initially provided for both the (1) flat price case and the (2) forecast price case.

Flat (or Fixed) Price One Line Economic Summary

O N E L I N E S U M M A R Y

LEASE NAME	INITIAL WORK INT	INITIAL REV INT	GROSS OIL (MB)	GROSS GAS (MMcf)	NET OIL (MB)	NET GAS (MMcf)	AVG OIL PRICE ($/BBL)	AVG GAS PRICE ($/Mcf)	OIL REV (M$)	GAS REV (M$)	AD VAL & PROD TAX (M$)	OPER. EXPENSE (M$)	TOTAL INVEST. (M$)	BFIT NET INCOME (M$)	DISC 10% NET INC (M$)
LA ROSA C-14 PDP	81.25000	64.80000	32.5	32.5	21.0	21.0	64.20	7.70	1,350.1	161.9	74.2	266.9	0.0	1,170.9	1,010.7
LA ROSA GAS UNIT 47	81.25000	64.80000	0.0	41.8	0.0	27.1	0.00	7.70	0.0	208.5	15.6	102.4	0.0	90.4	82.6
LA ROSA GAS UNIT 52	81.25000	64.80000	0.0	34.4	0.0	22.3	0.00	7.70	0.0	171.7	12.9	120.7	0.0	38.2	35.2
LA ROSA UNIT 46	81.25000	64.80000	0.0	45.0	0.0	29.2	0.00	7.70	0.0	224.6	16.8	146.3	0.0	61.5	56.9
LAROSA GAS UNIT 16	81.25000	64.80000	0.0	812.1	0.0	526.3	0.00	7.70	0.0	4,052.1	303.9	2,047.5	0.0	1,700.7	656.6
LAROSA OIL	81.25000	64.80000	27.3	4.9	17.7	3.2	64.20	7.70	1,133.9	24.4	54.0	482.6	0.0	621.7	472.7
ROOKE C-10	81.25000	64.80000	0.0	195.3	0.0	126.5	0.00	7.70	0.0	974.4	73.1	241.3	0.0	660.0	578.3
ROOKE GAS UNIT 1-A	81.25000	64.80000	0.0	89.4	0.0	57.9	0.00	7.70	0.0	446.1	33.5	182.8	0.0	229.8	203.1
PROVED DEVELOPED PRODUCING			**59.7**	**1,255.4**	**38.7**	**813.5**	**64.20**	**7.70**	**2,484.0**	**6,263.8**	**584.0**	**3,590.4**	**0.0**	**4,573.3**	**3,095.0**
LA ROSA C-14 PDNP	81.25000	64.80000	100.0	50.0	64.8	32.4	64.20	7.70	4,160.0	249.5	210.1	332.7	40.6	3,826.1	1,803.7
PROVED DEVELOPED NON-PRODUCING			**100.0**	**50.0**	**64.8**	**32.4**	**64.20**	**7.70**	**4,160.0**	**249.5**	**210.1**	**332.7**	**40.6**	**3,826.1**	**1,803.7**
LA ROSA C-15 PUD	81.25000	64.80000	0.0	176.8	0.0	114.6	0.00	7.70	0.0	882.2	66.2	135.3	0.0	680.8	622.2
LA ROSA C-16 PUD	81.25000	64.80000	0.0	363.7	0.0	235.6	0.00	7.70	0.0	1,814.5	136.1	204.8	0.0	1,473.7	1,291.4
LA ROSA C-17 PUD	81.25000	64.80000	127.1	63.6	82.4	41.2	64.20	7.70	5,288.0	317.1	267.0	416.8	0.0	4,921.3	3,911.9
LA ROSA C-18 PUD	81.25000	64.80000	127.1	63.6	82.4	41.2	64.20	7.70	5,288.0	317.1	267.0	416.8	812.5	4,108.8	3,020.1
LA ROSA C-18 PUD BP1	81.25000	64.80000	85.1	42.6	55.2	27.6	64.20	7.70	3,541.3	212.4	178.8	446.1	40.6	3,088.1	940.0
MICHNA NO 13 PUD	81.25000	64.80000	0.0	199.9	0.0	129.5	0.00	7.70	0.0	997.4	74.8	142.6	243.8	536.2	447.0
PROVED UNDEVELOPED			**339.4**	**910.1**	**219.9**	**589.7**	**64.20**	**7.70**	**14,117.2**	**4,540.7**	**989.9**	**1,762.3**	**1,096.9**	**14,808.8**	**10,232.6**
3390 NO. BRIGHT SPOT	81.25000	64.80000	0.0	240.0	0.0	155.5	0.00	7.70	0.0	1,197.5	89.8	171.8	243.8	692.1	551.2
3390 SO. BRIGHT SPOT	81.25000	64.80000	0.0	439.4	0.0	284.7	0.00	7.70	0.0	2,192.5	164.4	252.3	243.8	1,532.0	1,172.7
3450' MICHNA #12	81.25000	64.80000	0.0	293.3	0.0	190.1	0.00	7.70	0.0	1,463.6	109.8	208.4	243.8	901.7	639.7
3800 NO. BRIGHT SPOT	81.25000	64.80000	0.0	320.0	0.0	207.4	0.00	7.70	0.0	1,596.6	119.7	175.5	243.8	1,057.6	842.8
3800 SO. BRIGHT SPOT	81.25000	64.80000	0.0	720.0	0.0	466.5	0.00	7.70	0.0	3,592.4	269.4	391.2	243.8	2,688.0	1,890.4
5200' YARROW #1	81.25000	64.80000	0.0	479.5	0.0	310.7	0.00	7.70	0.0	2,392.7	179.4	259.6	446.9	1,506.7	1,028.6
6200' NORTH A1	81.25000	64.80000	0.0	1,000.0	0.0	648.0	0.00	7.70	0.0	4,989.4	374.2	380.3	609.4	3,625.6	2,454.2
6200' NORTH C-6	81.25000	64.80000	0.0	1,000.0	0.0	648.0	0.00	7.70	0.0	4,989.4	374.2	380.3	609.4	3,625.6	2,473.8
6200' NORTH LOC4	81.25000	64.80000	0.0	1,649.6	0.0	1,068.9	0.00	7.70	0.0	8,230.7	617.3	464.3	609.4	6,539.7	4,378.8
6500' LOC4	81.25000	64.80000	0.0	1,299.4	0.0	842.0	0.00	7.70	0.0	6,483.2	486.2	405.8	609.4	4,981.8	3,391.6
6500' LOC5	81.25000	64.80000	0.0	1,584.0	0.0	1,026.4	0.00	7.70	0.0	7,903.3	592.7	497.3	609.4	6,203.9	4,058.4
BELOW DRISCOLL A #1	81.25000	64.80000	65.0	0.0	42.1	0.0	64.20	0.00	2,702.3	0.0	124.3	285.2	731.3	1,561.6	970.9
BELOW DRISCOLL A #2	81.25000	64.80000	138.0	0.0	89.4	0.0	64.20	0.00	5,740.8	0.0	264.1	497.3	731.3	4,248.3	2,469.6
BELOW DRISCOLL A #3	81.25000	64.80000	0.0	384.0	0.0	248.8	0.00	7.70	0.0	1,915.9	143.7	146.3	731.3	894.7	606.4
DRISCOLL 8,000	81.25000	64.80000	22.5	150.0	14.6	97.2	64.20	7.70	936.0	748.4	99.2	109.7	731.3	744.3	515.1
GRETA 1	81.25000	64.80000	60.0	0.0	38.9	0.0	64.20	0.00	2,495.6	0.0	114.8	347.3	325.0	1,708.5	1,145.6
GRETA 2	81.25000	64.80000	60.0	0.0	38.9	0.0	64.20	0.00	2,495.6	0.0	114.8	347.3	325.0	1,708.5	1,145.6
GRETA 3	81.25000	64.80000	60.0	0.0	38.9	0.0	64.20	0.00	2,495.6	0.0	114.8	347.3	325.0	1,708.5	1,145.6
ROOKE HIGH - 7500'	81.25000	64.80000	0.0	136.0	0.0	88.1	0.00	7.70	0.0	678.6	50.9	98.7	40.6	488.3	382.5
ROOKE HIGH 6,900'	81.25000	64.80000	60.0	0.0	38.9	0.0	64.20	0.00	2,495.6	0.0	114.8	347.3	406.3	1,627.2	1,024.0
ROOKE HIGH 7,300'#1	81.25000	64.80000	150.0	0.0	97.2	0.0	64.20	0.00	6,240.0	0.0	287.0	661.8	406.3	4,885.0	2,717.6

1

ONE LINE SUMMARY

LEASE NAME	INITIAL WORK INT	INITIAL REV INT	GROSS OIL (MB)	GROSS GAS (MMcf)	NET OIL (MB)	NET GAS (MMcf)	AVG OIL PRICE ($/BBL)	AVG GAS PRICE ($/Mcf)	OIL REV (M$)	GAS REV (M$)	AD VAL & PROD TAX (M$)	OPER. EXPENSE (M$)	TOTAL INVEST. (M$)	BFIT NET INCOME (M$)	DISC 10% NET INC (M$)
ROOKE HIGH 7,300'#2	81.25000	64.80000	150.0	0.0	97.2	0.0	64.20	0.00	6,240.0	0.0	287.0	661.8	406.3	4,885.0	2,717.6
ROOKE HIGH 7,300'#3	81.25000	64.80000	150.0	0.0	97.2	0.0	64.20	0.00	6,240.0	0.0	287.0	661.8	406.3	4,885.0	2,717.6
SINTON, WEST 1	81.25000	64.80000	0.0	450.0	0.0	291.6	0.00	7.70	0.0	2,245.2	168.4	321.8	325.0	1,430.1	990.8
SINTON, WEST 2	81.25000	64.80000	0.0	271.8	0.0	176.1	0.00	7.70	0.0	1,356.1	101.7	193.8	243.8	816.9	612.9
SINTON, WEST 3	81.25000	64.80000	0.0	240.0	0.0	155.5	0.00	7.70	0.0	1,197.5	89.8	171.8	284.4	651.4	489.2
VICKSBURG #1	81.25000	64.80000	60.0	1,999.4	38.9	1,295.6	64.20	7.70	2,495.3	9,975.9	863.0	625.2	1,137.5	9,845.5	5,515.4
VICKSBURG #2	81.25000	64.80000	60.0	1,999.4	38.9	1,295.6	64.20	7.70	2,495.3	9,975.9	863.0	625.2	1,137.5	9,845.5	5,515.4
VICKSBURG #3	81.25000	64.80000	60.0	1,999.4	38.9	1,295.6	64.20	7.70	2,495.3	9,975.9	863.0	625.2	1,137.5	9,845.5	5,471.8
VICKSBURG #4	81.25000	64.80000	60.0	1,999.4	38.9	1,295.6	64.20	7.70	2,495.3	9,975.9	863.0	625.2	1,137.5	9,845.5	5,428.5
VICKSBURG #5	81.25000	64.80000	60.0	1,999.4	38.9	1,295.6	64.20	7.70	2,495.3	9,975.9	863.0	625.2	1,137.5	9,845.5	5,428.5
WYRICK 1	81.25000	64.80000	144.0	0.0	93.3	0.0	64.20	0.00	5,990.4	0.0	275.6	519.2	325.0	4,870.7	3,187.1
WYRICK 2	81.25000	64.80000	144.0	0.0	93.3	0.0	64.20	0.00	5,990.4	0.0	275.6	519.2	325.0	4,870.7	3,187.1
WYRICK 3	81.25000	64.80000	144.0	0.0	93.3	0.0	64.20	0.00	5,990.4	0.0	275.6	519.2	325.0	4,870.7	3,187.1
PROBABLE			**1,647.3**	**20,654.2**	**1,067.4**	**13,383.5**	**64.20**	**7.70**	**68,529.4**	**103,052.8**	**10,881.3**	**13,469.6**	**17,793.8**	**129,437.5**	**79,453.7**
VICKSBURG #10	81.25000	64.80000	60.0	2,999.9	38.9	1,943.9	64.20	7.70	2,495.9	14,967.7	1,237.4	939.7	1,137.5	14,149.1	6,593.0
VICKSBURG #6	81.25000	64.80000	60.0	2,999.9	38.9	1,943.9	64.20	7.70	2,495.9	14,967.7	1,237.4	939.7	1,137.5	14,149.1	6,805.8
VICKSBURG #7	81.25000	64.80000	60.0	2,999.9	38.9	1,943.9	64.20	7.70	2,495.9	14,967.7	1,237.4	939.7	1,137.5	14,149.1	6,752.0
VICKSBURG #8	81.25000	64.80000	60.0	2,999.9	38.9	1,943.9	64.20	7.70	2,495.9	14,967.7	1,237.4	939.7	1,137.5	14,149.1	6,698.6
VICKSBURG #9	81.25000	64.80000	60.0	2,999.9	38.9	1,943.9	64.20	7.70	2,495.9	14,967.7	1,237.4	939.7	1,137.5	14,149.1	6,645.6
POSSIBLE			**300.0**	**14,999.4**	**194.4**	**9,719.3**	**64.20**	**7.70**	**12,479.6**	**74,838.7**	**6,187.0**	**4,698.3**	**5,687.5**	**70,745.5**	**33,494.9**
GRAND TOTAL			**2,446.4**	**37,869.1**	**1,585.2**	**24,538.4**	**64.20**	**7.70**	**101,770.2**	**188,945.5**	**18,852.3**	**23,853.4**	**24,618.8**	**223,391.2**	**128,079.8**

Forecast Price (NYMEX futures projections) One Line Economic Summary

O N E L I N E S U M M A R Y

LEASE NAME	INITIAL WORK INT	INITIAL REV INT	GROSS OIL (MB)	GROSS GAS (MMcf)	NET OIL (MB)	NET GAS (MMcf)	AVG OIL PRICE ($/BBL)	AVG GAS PRICE ($/Mcf)	OIL REV (M$)	GAS REV (M$)	AD VAL & PROD TAX (M$)	OPER. EXPENSE (M$)	TOTAL INVEST. (M$)	BFIT NET INCOME (M$)	DISC 10% NET INC (M$)
LA ROSA C-14 PDP	81.25000	64.80000	32.3	32.3	20.9	20.9	61.75	6.96	1,291.0	145.5	70.3	259.6	0.0	1,106.6	968.2
LA ROSA GAS UNIT 47	81.25000	64.80000	0.0	41.8	0.0	27.1	0.00	7.26	0.0	196.5	14.7	102.4	0.0	79.4	72.9
LA ROSA GAS UNIT 52	81.25000	64.80000	0.0	27.6	0.0	17.9	0.00	7.30	0.0	130.8	9.8	91.4	0.0	29.6	27.7
LA ROSA UNIT 46	81.25000	64.80000	0.0	38.3	0.0	24.8	0.00	7.21	0.0	178.8	13.4	117.0	0.0	48.4	44.7
LAROSA GAS UNIT 16	81.25000	64.80000	0.0	664.1	0.0	430.3	0.00	5.85	0.0	2,519.1	188.9	1,466.2	0.0	864.0	436.6
LAROSA OIL	81.25000	64.80000	24.9	4.9	16.1	3.2	57.37	6.96	923.9	22.1	44.2	398.5	0.0	503.3	405.7
ROOKE C-10	81.25000	64.80000	0.0	188.1	0.0	121.9	0.00	7.02	0.0	855.8	64.2	212.1	0.0	579.5	515.4
ROOKE GAS UNIT 1-A	81.25000	64.80000	0.0	85.6	0.0	55.4	0.00	7.07	0.0	391.9	29.4	168.2	0.0	194.3	174.7
PROVED DEVELOPED PRODUCING			**57.1**	**1,082.5**	**37.0**	**701.5**	**59.84**	**6.33**	**2,214.9**	**4,440.4**	**434.9**	**2,815.3**	**0.0**	**3,405.1**	**2,645.9**
LA ROSA C-14 PDNP	81.25000	64.80000	100.0	50.0	64.8	32.4	49.85	5.64	3,230.2	182.9	162.3	332.7	40.6	2,877.4	1,382.9
PROVED DEVELOPED NON-PRODUCING			**100.0**	**50.0**	**64.8**	**32.4**	**49.85**	**5.64**	**3,230.2**	**182.9**	**162.3**	**332.7**	**40.6**	**2,877.4**	**1,382.9**
LA ROSA C-15 PUD	81.25000	64.80000	0.0	176.8	0.0	114.6	0.00	7.25	0.0	830.4	62.3	135.3	0.0	632.8	580.6
LA ROSA C-16 PUD	81.25000	64.80000	0.0	363.7	0.0	235.6	0.00	7.08	0.0	1,667.9	125.1	204.8	0.0	1,338.1	1,182.2
LA ROSA C-17 PUD	81.25000	64.80000	127.1	63.6	82.4	41.2	59.51	6.71	4,901.8	276.2	246.2	416.8	0.0	4,515.0	3,659.3
LA ROSA C-18 PUD	81.25000	64.80000	127.1	63.6	82.4	41.2	58.85	6.63	4,847.7	273.2	243.5	416.8	812.5	3,648.1	2,730.2
LA ROSA C-18 PUD BP1	81.25000	64.80000	85.1	42.6	55.2	27.6	49.90	5.62	2,752.5	155.0	138.2	446.1	40.6	2,282.6	699.1
MICHNA NO 13 PUD	81.25000	64.80000	0.0	199.9	0.0	129.5	0.00	7.13	0.0	923.6	69.3	142.6	243.8	468.0	390.4
PROVED UNDEVELOPED			**339.4**	**910.1**	**219.9**	**589.7**	**56.85**	**7.00**	**12,502.0**	**4,126.3**	**884.6**	**1,762.3**	**1,096.9**	**12,884.5**	**9,241.9**
3390 NO. BRIGHT SPOT	81.25000	64.80000	0.0	240.0	0.0	155.5	0.00	6.92	0.0	1,075.6	80.7	171.8	243.8	579.4	463.2
3390 SO. BRIGHT SPOT	81.25000	64.80000	0.0	439.4	0.0	284.7	0.00	6.67	0.0	1,900.4	142.5	252.3	243.8	1,261.8	977.6
3450' MICHNA #12	81.25000	64.80000	0.0	293.3	0.0	190.1	0.00	6.38	0.0	1,212.8	91.0	208.4	243.8	669.7	475.7
3800 NO. BRIGHT SPOT	81.25000	64.80000	0.0	319.2	0.0	206.8	0.00	6.86	0.0	1,419.1	106.4	171.8	243.8	897.0	718.6
3800 SO. BRIGHT SPOT	81.25000	64.80000	0.0	720.0	0.0	466.5	0.00	6.39	0.0	2,981.3	223.6	391.2	243.8	2,122.7	1,524.5
5200' YARROW #1	81.25000	64.80000	0.0	479.5	0.0	310.7	0.00	6.31	0.0	1,961.4	147.1	259.6	446.9	1,107.8	756.0
6200' NORTH A1	81.25000	64.80000	0.0	999.0	0.0	647.3	0.00	6.29	0.0	4,069.1	305.2	376.6	609.4	2,777.9	1,899.0
6200' NORTH C-6	81.25000	64.80000	0.0	999.0	0.0	647.3	0.00	6.32	0.0	4,091.0	306.8	376.6	609.4	2,798.2	1,930.1
6200' NORTH LOC4	81.25000	64.80000	0.0	1,649.6	0.0	1,068.9	0.00	6.24	0.0	6,672.8	500.5	464.3	609.4	5,098.7	3,463.5
6500' LOC4	81.25000	64.80000	0.0	1,299.4	0.0	842.0	0.00	6.28	0.0	5,289.9	396.7	405.8	609.4	3,878.0	2,672.0
6500' LOC5	81.25000	64.80000	0.0	1,584.0	0.0	1,026.4	0.00	6.20	0.0	6,366.7	477.5	497.3	609.4	4,782.6	3,177.6
BELOW DRISCOLL A #1	81.25000	64.80000	65.0	0.0	42.1	0.0	55.07	0.00	2,317.9	0.0	106.6	285.2	731.3	1,194.9	737.9
BELOW DRISCOLL A #2	81.25000	64.80000	138.0	0.0	89.4	0.0	53.43	0.00	4,777.8	0.0	219.8	497.3	731.3	3,329.6	1,954.3
BELOW DRISCOLL A #3	81.25000	64.80000	0.0	384.0	0.0	248.8	0.00	6.38	0.0	1,588.7	119.2	146.3	731.3	592.0	389.3
DRISCOLL 8,000	81.25000	64.80000	22.5	150.0	14.6	97.2	58.28	6.51	849.8	633.0	86.6	109.7	731.3	555.3	375.1
GRETA 1	81.25000	64.80000	60.0	0.0	38.9	0.0	55.98	0.00	2,175.9	0.0	100.1	347.3	325.0	1,403.5	956.0
GRETA 2	81.25000	64.80000	60.0	0.0	38.9	0.0	55.98	0.00	2,175.9	0.0	100.1	347.3	325.0	1,403.5	956.0
GRETA 3	81.25000	64.80000	60.0	0.0	38.9	0.0	55.98	0.00	2,175.9	0.0	100.1	347.3	325.0	1,403.5	956.0
ROOKE HIGH - 7500'	81.25000	64.80000	0.0	135.1	0.0	87.6	0.00	6.64	0.0	581.7	43.6	95.1	40.6	402.4	315.8
ROOKE HIGH 6,900'	81.25000	64.80000	60.0	0.0	38.9	0.0	54.79	0.00	2,129.7	0.0	98.0	347.3	406.3	1,278.1	811.6
ROOKE HIGH 7,300'#1	81.25000	64.80000	149.9	0.0	97.1	0.0	53.05	0.00	5,152.8	0.0	237.0	658.1	406.3	3,851.4	2,190.2

O N E L I N E S U M M A R Y

LEASE NAME	INITIAL WORK INT	INITIAL REV INT	GROSS OIL (MB)	GROSS GAS (MMcf)	NET OIL (MB)	NET GAS (MMcf)	AVG OIL PRICE ($/BBL)	AVG GAS PRICE ($/Mcf)	OIL REV (M$)	GAS REV (M$)	AD VAL & PROD TAX (M$)	OPER. EXPENSE (M$)	TOTAL INVEST. (M$)	BFIT NET INCOME (M$)	DISC 10% NET INC (M$)
ROOKE HIGH 7,300'#2	81.25000	64.80000	149.9	0.0	97.1	0.0	53.05	0.00	5,152.8	0.0	237.0	658.1	406.3	3,851.4	2,190.2
ROOKE HIGH 7,300'#3	81.25000	64.80000	149.9	0.0	97.1	0.0	53.05	0.00	5,152.8	0.0	237.0	658.1	406.3	3,851.4	2,190.2
SINTON, WEST 1	81.25000	64.80000	0.0	450.0	0.0	291.6	0.00	6.41	0.0	1,868.5	140.1	321.8	325.0	1,081.6	758.9
SINTON, WEST 2	81.25000	64.80000	0.0	271.8	0.0	176.1	0.00	6.65	0.0	1,170.4	87.8	193.8	243.8	645.1	486.1
SINTON, WEST 3	81.25000	64.80000	0.0	240.0	0.0	155.5	0.00	6.71	0.0	1,043.1	78.2	171.8	284.4	508.7	381.6
VICKSBURG #1	81.25000	64.80000	60.0	1,999.4	38.9	1,295.6	52.97	5.95	2,059.0	7,708.9	672.9	625.2	1,137.5	7,332.2	4,140.1
VICKSBURG #2	81.25000	64.80000	60.0	1,999.4	38.9	1,295.6	52.97	5.95	2,059.0	7,708.9	672.9	625.2	1,137.5	7,332.2	4,140.1
VICKSBURG #3	81.25000	64.80000	60.0	1,999.4	38.9	1,295.6	52.81	5.93	2,052.7	7,686.8	670.9	625.2	1,137.5	7,305.9	4,088.7
VICKSBURG #4	81.25000	64.80000	60.0	1,999.4	38.9	1,295.6	52.65	5.92	2,046.4	7,664.3	669.0	625.2	1,137.5	7,279.0	4,037.4
VICKSBURG #5	81.25000	64.80000	60.0	1,999.4	38.9	1,295.6	52.65	5.92	2,046.4	7,664.3	669.0	625.2	1,137.5	7,279.0	4,037.4
WYRICK 1	81.25000	64.80000	144.0	0.0	93.3	0.0	55.33	0.00	5,163.2	0.0	237.5	519.2	325.0	4,081.5	2,733.2
WYRICK 2	81.25000	64.80000	144.0	0.0	93.3	0.0	55.33	0.00	5,163.2	0.0	237.5	519.2	325.0	4,081.5	2,733.2
WYRICK 3	81.25000	64.80000	144.0	0.0	93.3	0.0	55.33	0.00	5,163.2	0.0	237.5	519.2	325.0	4,081.5	2,733.2
PROBABLE			**1,647.0**	**20,650.4**	**1,067.3**	**13,381.0**	**54.17**	**6.15**	**57,814.2**	**82,358.7**	**8,836.4**	**13,444.0**	**17,793.8**	**100,098.8**	**62,350.5**
VICKSBURG #10	81.25000	64.80000	60.0	2,999.9	38.9	1,943.9	51.44	5.79	1,999.7	11,245.3	935.4	939.7	1,137.5	10,232.4	4,795.1
VICKSBURG #6	81.25000	64.80000	60.0	2,999.9	38.9	1,943.9	51.75	5.82	2,011.9	11,314.4	941.1	939.7	1,137.5	10,308.0	5,001.1
VICKSBURG #7	81.25000	64.80000	60.0	2,999.9	38.9	1,943.9	51.67	5.81	2,008.9	11,297.5	939.7	939.7	1,137.5	10,289.5	4,949.2
VICKSBURG #8	81.25000	64.80000	60.0	2,999.9	38.9	1,943.9	51.59	5.80	2,005.9	11,280.3	938.3	939.7	1,137.5	10,270.7	4,897.6
VICKSBURG #9	81.25000	64.80000	60.0	2,999.9	38.9	1,943.9	51.52	5.79	2,002.8	11,262.9	936.8	939.7	1,137.5	10,251.7	4,846.2
POSSIBLE			**300.0**	**14,999.4**	**194.4**	**9,719.3**	**51.59**	**5.80**	**10,029.1**	**56,400.4**	**4,691.4**	**4,698.3**	**5,687.5**	**51,352.3**	**24,489.2**
GRAND TOTAL			**2,443.5**	**37,692.5**	**1,583.3**	**24,423.9**	**54.18**	**6.04**	**85,790.3**	**147,508.7**	**15,009.5**	**23,052.7**	**24,618.8**	**170,618.1**	**100,110.5**

Full Economic Case Summaries by Reserve Category and Aggregation (Flat and Forecast Pricing):

LAROSA FIELD
GRAND TOTAL
PDP+PDNP+PUD+PROB+POSS

FLAT PRICE CASE

DATE : 06/22/07
TIME : 00:00:05
DBS FILE : LAROSA
SETUP FILE : QUA
SEQ NUMBER : *****

R E S E R V E S A N D E C O N O M I C S

AS OF DATE: 5/07

-END- MO-YR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-07	43.105	357.202	27.931	231.459	64.200	7.700	1793.173	1782.236	3575.409
12-08	119.817	1339.205	77.639	867.777	64.200	7.700	4984.427	6681.881	11666.310
12-09	303.640	3776.302	196.752	2446.964	64.200	7.700	12631.490	18841.620	31473.110
12-10	387.006	6396.174	250.772	4144.587	64.200	7.700	16099.560	31913.310	48012.870
12-11	308.246	5185.797	199.737	3360.287	64.200	7.700	12823.110	25874.210	38697.310
12-12	241.332	4005.040	156.378	2595.182	64.200	7.700	10039.480	19982.900	30022.380
12-13	214.256	3168.117	138.833	2052.873	64.200	7.700	8913.084	15807.120	24720.210
12-14	180.976	2540.917	117.268	1646.461	64.200	7.700	7528.630	12677.750	20206.380
12-15	141.332	2052.381	91.580	1329.900	64.200	7.700	5879.455	10240.230	16119.680
12-16	107.139	1667.794	69.424	1080.696	64.200	7.700	4457.015	8321.356	12778.370
12-17	93.883	1352.859	60.834	876.624	64.200	7.700	3905.573	6750.006	10655.580
12-18	78.117	1089.990	50.618	706.290	64.200	7.700	3249.690	5438.435	8688.125
12-19	62.442	899.010	40.461	582.540	64.200	7.700	2597.584	4485.554	7083.138
12-20	46.957	733.643	30.427	475.385	64.200	7.700	1953.424	3660.467	5613.892
12-21	32.037	614.397	20.759	398.116	64.200	7.700	1332.750	3065.496	4398.246
S TOT	2360.285	35178.820	1529.415	22795.140	64.200	7.700	98188.450	175522.600	273711.000
AFTER	86.099	2690.260	55.790	1743.232	64.200	7.700	3581.745	13422.890	17004.630
TOTAL	2446.384	37869.080	1585.205	24538.370	64.200	7.700	101770.200	188945.400	290715.600

-END- MO-YR	NET ADVAL & PROD. TAXES -----M$----	DIRECT OPER EXPENSE -----M$----	SALVAGE VALUE -----M$----	ABANDON COST -----M$----	CAPITAL EXPENSE -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-07	216.154	351.000	.000	.000	1056.250	1952.005	1952.005	1872.244
12-08	730.425	855.563	.000	.000	6825.000	3255.320	5207.325	4741.633
12-09	1994.170	1681.875	.000	.000	12106.250	15690.810	20898.140	17509.880
12-10	3134.078	2120.625	.000	.000	4550.000	38208.180	59106.320	45669.780
12-11	2530.429	2014.594	.000	.000	.000	34152.300	93258.610	68685.330
12-12	1960.534	1784.250	.000	.000	.000	26277.600	119536.200	84781.980
12-13	1595.536	1619.719	.000	.000	40.625	21464.330	141000.500	96722.950
12-14	1297.148	1535.625	.000	.000	.000	17373.600	158374.100	105518.000
12-15	1038.472	1488.094	.000	.000	.000	13593.120	171967.300	111773.800
12-16	829.124	1356.469	.000	.000	.000	10592.780	182560.000	116206.000
12-17	685.907	1122.469	.000	.000	40.625	8806.578	191366.600	119553.500
12-18	557.368	987.188	.000	.000	.000	7143.570	198510.200	122023.100
12-19	455.905	943.313	.000	.000	.000	5683.920	204194.100	123809.600
12-20	364.393	822.656	.000	.000	.000	4426.843	208621.000	125074.900
12-21	291.219	658.125	.000	.000	.000	3448.903	212069.900	125970.600
S TOT	17680.860	19341.560	.000	.000	24618.750	212069.900	212069.900	125970.600
AFTER	1171.477	4511.813	.000	.000	.000	11321.340	223391.200	128079.800
TOTAL	18852.330	23853.380	.000	.000	24618.750	223391.200	223391.200	128079.800

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	18.0	36.0	LIFE, YRS.	46.67	8.00	141355.600
GROSS ULT., MB & MMF	2611.002	39308.950	DISCOUNT %	10.00	10.00	128079.800
GROSS CUM., MB & MMF	164.617	1439.861	UNDISCOUNTED PAYOUT, YRS.	.23	15.00	102183.600
GROSS RES., MB & MMF	2446.384	37869.090	DISCOUNTED PAYOUT, YRS.	.24	20.00	83529.450
NET RES., MB & MMF	1585.205	24538.370	UNDISCOUNTED NET/INVEST.	10.07	25.00	69624.410
NET REVENUE, M$	101770.200	188945.500	DISCOUNTED NET/INVEST.	7.29	30.00	58971.520
INITIAL PRICE, $	64.200	7.700	RATE-OF-RETURN, PCT.	100.00	40.00	43961.630
INITIAL N.I., PCT.	64.798	64.798	INITIAL W.I., PCT.	81.250	50.00	34112.650
FINAL N.I., PCT.	64.798	64.798	FINAL W.I., PCT.	81.250	75.00	20455.620
					100.00	13818.790

LAROSA FIELD
TOTAL PROVED
PDP+PDNP+PUD

FLAT PRICE CASE

DATE : 06/22/07
TIME : 00:00:05
DBS FILE : LAROSA
SETUP FILE : QUA
SEQ NUMBER : *****

R E S E R V E S A N D E C O N O M I C S

AS OF DATE: 5/07

-END- MO-YR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-07	43.105	357.202	27.931	231.459	64.200	7.700	1793.173	1782.236	3575.409
12-08	71.489	476.672	46.324	308.874	64.200	7.700	2973.979	2378.328	5352.307
12-09	61.800	305.656	40.045	198.059	64.200	7.700	2570.883	1525.051	4095.934
12-10	43.965	173.342	28.489	112.322	64.200	7.700	1828.971	864.881	2693.852
12-11	31.072	88.307	20.134	57.221	64.200	7.700	1292.598	440.601	1733.199
12-12	22.060	45.737	14.294	29.636	64.200	7.700	917.699	228.201	1145.900
12-13	37.774	43.097	24.477	27.926	64.200	7.700	1571.395	215.031	1786.426
12-14	38.545	42.718	24.976	27.680	64.200	7.700	1603.471	213.138	1816.609
12-15	26.082	35.983	16.900	23.316	64.200	7.700	1085.010	179.535	1264.545
12-16	17.449	31.178	11.306	20.203	64.200	7.700	725.864	155.560	881.425
12-17	26.061	35.028	16.887	22.697	64.200	7.700	1084.157	174.770	1258.927
12-18	22.608	33.199	14.649	21.512	64.200	7.700	940.485	165.643	1106.128
12-19	16.692	29.911	10.816	19.382	64.200	7.700	694.393	149.239	843.632
12-20	12.480	27.299	8.087	17.689	64.200	7.700	519.173	136.208	655.380
12-21	7.917	24.524	5.130	15.891	64.200	7.700	329.359	122.361	451.719
S TOT	479.098	1749.853	310.446	1133.868	64.200	7.700	19930.610	8730.782	28661.390
AFTER	19.967	465.621	12.938	301.712	64.200	7.700	830.640	2323.186	3153.825
TOTAL	499.066	2215.474	323.384	1435.580	64.200	7.700	20761.250	11053.970	31815.220

-END- MO-YR	NET ADVAL & PROD. TAXES -----M$----	DIRECT OPER EXPENSE -----M$----	SALVAGE VALUE -----M$----	ABANDON COST -----M$----	CAPITAL EXPENSE -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-07	216.154	351.000	.000	.000	1056.250	1952.005	1952.005	1872.244
12-08	315.178	570.375	.000	.000	.000	4466.754	6418.759	5878.174
12-09	232.639	555.750	.000	.000	.000	3307.545	9726.304	8578.522
12-10	148.999	446.063	.000	.000	.000	2098.790	11825.090	10136.880
12-11	92.505	329.063	.000	.000	.000	1311.632	13136.730	11021.980
12-12	59.329	255.938	.000	.000	.000	830.633	13967.360	11531.420
12-13	88.411	219.375	.000	.000	40.625	1438.015	15405.370	12321.610
12-14	89.745	219.375	.000	.000	.000	1507.489	16912.860	13085.820
12-15	63.376	219.375	.000	.000	.000	981.795	17894.660	13538.340
12-16	45.057	212.063	.000	.000	.000	624.306	18518.960	13800.050
12-17	62.979	175.500	.000	.000	40.625	979.823	19498.790	14170.730
12-18	55.686	146.250	.000	.000	.000	904.192	20402.980	14483.450
12-19	43.135	131.625	.000	.000	.000	668.872	21071.850	14693.800
12-20	34.098	131.625	.000	.000	.000	489.658	21561.510	14833.810
12-21	24.328	87.750	.000	.000	.000	339.642	21901.150	14922.050
S TOT	1571.617	4051.125	.000	.000	1137.500	21901.150	21901.150	14922.050
AFTER	212.448	1634.344	.000	.000	.000	1307.033	23208.180	15131.310
TOTAL	1784.065	5685.469	.000	.000	1137.500	23208.180	23208.180	15131.310

	OIL	GAS
GROSS WELLS	6.0	9.0
GROSS ULT., MB & MMF	663.683	3655.334
GROSS CUM., MB & MMF	164.617	1439.861
GROSS RES., MB & MMF	499.066	2215.474
NET RES., MB & MMF	323.384	1435.580
NET REVENUE, M$	20761.250	11053.970
INITIAL PRICE, $	64.200	7.700
INITIAL N.I., PCT.	64.798	64.798
FINAL N.I., PCT.	64.798	64.798

LIFE, YRS.	46.67
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	.23
DISCOUNTED PAYOUT, YRS.	.24
UNDISCOUNTED NET/INVEST.	21.40
DISCOUNTED NET/INVEST.	15.08
RATE-OF-RETURN, PCT.	100.00
INITIAL W.I., PCT.	81.250
FINAL W.I., PCT.	81.250

P.W. %	P.W., M$
8.00	16220.630
10.00	15131.310
15.00	13015.220
20.00	11481.740
25.00	10318.730
30.00	9404.717
40.00	8054.134
50.00	7096.734
75.00	5573.122
100.00	4659.890

LAROSA FIELD
PROVED PRODUCING

FLAT PRICE CASE

DATE : 06/22/07
TIME : 00:00:01
DBS FILE : LAROSA
SETUP FILE : QUA
SEQ NUMBER : *****

R E S E R V E S A N D E C O N O M I C S

AS OF DATE: 5/07

-END- MO-YR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-07	11.472	139.059	7.433	90.107	64.200	7.700	477.219	693.824	1171.043
12-08	13.089	166.094	8.482	107.626	64.200	7.700	544.525	828.717	1373.242
12-09	9.538	123.694	6.181	80.151	64.200	7.700	396.789	617.162	1013.951
12-10	7.078	78.177	4.586	50.657	64.200	7.700	294.433	390.057	684.490
12-11	5.353	51.322	3.469	33.256	64.200	7.700	222.706	256.070	478.776
12-12	4.129	36.771	2.675	23.827	64.200	7.700	171.762	183.468	355.230
12-13	2.610	25.515	1.691	16.533	64.200	7.700	108.561	127.307	235.867
12-14	1.828	24.359	1.184	15.784	64.200	7.700	76.029	121.539	197.569
12-15	1.602	23.743	1.038	15.385	64.200	7.700	66.656	118.466	185.121
12-16	1.405	23.156	.910	15.005	64.200	7.700	58.438	115.536	173.973
12-17	1.232	22.613	.798	14.653	64.200	7.700	51.233	112.826	164.059
12-18	.376	22.083	.244	14.309	64.200	7.700	15.633	110.180	125.814
12-19	.000	21.565	.000	13.974	.000	7.700	.000	107.597	107.597
12-20	.000	21.059	.000	13.646	.000	7.700	.000	105.074	105.074
12-21	.000	20.565	.000	13.326	.000	7.700	.000	102.610	102.610
S TOT	59.711	799.776	38.691	518.238	64.200	7.700	2483.984	3990.431	6474.414
AFTER	.000	455.637	.000	295.243	.000	7.700	.000	2273.373	2273.373
TOTAL	59.711	1255.413	38.691	813.481	64.200	7.700	2483.984	6263.804	8747.787

-END- MO-YR	NET ADVAL & PROD. TAXES -----M$----	DIRECT OPER EXPENSE -----M$----	SALVAGE VALUE -----M$----	ABANDON COST -----M$----	CAPITAL EXPENSE -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-07	73.989	234.000	.000	.000	.000	863.054	863.054	837.335
12-08	87.202	351.000	.000	.000	.000	935.040	1798.094	1676.927
12-09	64.539	336.375	.000	.000	.000	613.037	2411.130	2177.623
12-10	42.798	252.281	.000	.000	.000	389.410	2800.541	2466.658
12-11	29.450	197.438	.000	.000	.000	251.889	3052.429	2636.662
12-12	21.661	168.188	.000	.000	.000	165.382	3217.811	2738.090
12-13	14.542	106.031	.000	.000	.000	115.294	3333.105	2802.322
12-14	12.613	87.750	.000	.000	.000	97.206	3430.311	2851.485
12-15	11.951	87.750	.000	.000	.000	85.420	3515.731	2890.762
12-16	11.353	87.750	.000	.000	.000	74.870	3590.601	2922.058
12-17	10.819	87.750	.000	.000	.000	65.490	3656.092	2946.946
12-18	8.983	58.500	.000	.000	.000	58.331	3714.423	2967.086
12-19	8.070	43.875	.000	.000	.000	55.652	3770.075	2984.551
12-20	7.881	43.875	.000	.000	.000	53.318	3823.393	2999.763
12-21	7.696	43.875	.000	.000	.000	51.039	3874.432	3013.001
S TOT	413.546	2186.438	.000	.000	.000	3874.432	3874.432	3013.001
AFTER	170.503	1404.000	.000	.000	.000	698.870	4573.302	3095.021
TOTAL	584.049	3590.438	.000	.000	.000	4573.302	4573.302	3095.021

	OIL	GAS
GROSS WELLS	2.0	6.0
GROSS ULT., MB & MMF	224.328	2647.857
GROSS CUM., MB & MMF	164.617	1392.445
GROSS RES., MB & MMF	59.711	1255.413
NET RES., MB & MMF	38.691	813.481
NET REVENUE, M$	2483.984	6263.805
INITIAL PRICE, $	64.200	7.700
INITIAL N.I., PCT.	64.798	64.798
FINAL N.I., PCT.	64.798	64.798

LIFE, YRS.	46.67
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	.00
DISCOUNTED PAYOUT, YRS.	.00
UNDISCOUNTED NET/INVEST.	.00
DISCOUNTED NET/INVEST.	.00
RATE-OF-RETURN, PCT.	100.00
INITIAL W.I., PCT.	81.250
FINAL W.I., PCT.	81.250

P.W. %	P.W., M$
8.00	3264.986
10.00	3095.022
15.00	2774.202
20.00	2541.853
25.00	2361.211
30.00	2214.507
40.00	1987.157
50.00	1816.693
75.00	1527.409
100.00	1343.040

LAROSA FIELD
PROVED NON PRODUCING

FLAT PRICE CASE

DATE : 06/22/07
TIME : 00:00:01
DBS FILE : LAROSA
SETUP FILE : QUA
SEQ NUMBER : *****

R E S E R V E S A N D E C O N O M I C S

AS OF DATE: 5/07

-END- MO-YR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-07	.000	.000	.000	.000	.000	.000	.000	.000	.000
12-08	.000	.000	.000	.000	.000	.000	.000	.000	.000
12-09	.000	.000	.000	.000	.000	.000	.000	.000	.000
12-10	.000	.000	.000	.000	.000	.000	.000	.000	.000
12-11	.000	.000	.000	.000	.000	.000	.000	.000	.000
12-12	.000	.000	.000	.000	.000	.000	.000	.000	.000
12-13	22.662	11.331	14.685	7.342	64.200	7.700	942.761	56.536	999.298
12-14	28.001	14.000	18.144	9.072	64.200	7.700	1164.843	69.854	1234.697
12-15	18.402	9.201	11.924	5.962	64.200	7.700	765.548	45.909	811.457
12-16	12.094	6.047	7.837	3.918	64.200	7.700	503.126	30.172	533.298
12-17	7.949	3.974	5.150	2.575	64.200	7.700	330.660	19.829	350.489
12-18	5.224	2.612	3.385	1.692	64.200	7.700	217.314	13.032	230.346
12-19	3.433	1.717	2.225	1.112	64.200	7.700	142.821	8.565	151.386
12-20	2.234	1.117	1.448	.724	64.200	7.700	92.951	5.574	98.525
12-21									
S TOT	100.000	50.000	64.798	32.399	64.200	7.700	4160.023	249.472	4409.495
AFTER	.000	.000	.000	.000	.000	.000	.000	.000	.000
TOTAL	100.000	50.000	64.798	32.399	64.200	7.700	4160.023	249.472	4409.495

-END- MO-YR	NET ADVAL & PROD. TAXES -----M$----	DIRECT OPER EXPENSE -----M$----	SALVAGE VALUE -----M$----	ABANDON COST -----M$----	CAPITAL EXPENSE -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-07	.000	.000	.000	.000	.000	.000	.000	.000
12-08	.000	.000	.000	.000	.000	.000	.000	.000
12-09	.000	.000	.000	.000	.000	.000	.000	.000
12-10	.000	.000	.000	.000	.000	.000	.000	.000
12-11	.000	.000	.000	.000	.000	.000	.000	.000
12-12	.000	.000	.000	.000	.000	.000	.000	.000
12-13	47.607	25.594	.000	.000	40.625	885.472	885.472	482.111
12-14	58.822	43.875	.000	.000	.000	1132.000	2017.472	1056.028
12-15	38.658	43.875	.000	.000	.000	728.923	2746.395	1392.015
12-16	25.407	43.875	.000	.000	.000	464.017	3210.412	1586.476
12-17	16.698	43.875	.000	.000	.000	289.917	3500.329	1696.949
12-18	10.974	43.875	.000	.000	.000	175.497	3675.825	1757.763
12-19	7.212	43.875	.000	.000	.000	100.299	3776.124	1789.379
12-20	4.694	43.875	.000	.000	.000	49.956	3826.080	1803.727
12-21								
S TOT	210.071	332.719	.000	.000	40.625	3826.080	3826.080	1803.727
AFTER	.000	.000	.000	.000	.000	.000	3826.080	1803.727
TOTAL	210.071	332.719	.000	.000	40.625	3826.080	3826.080	1803.727

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	1.0	.0	LIFE, YRS.	13.67	8.00	2081.219
GROSS ULT., MB & MMF	100.000	50.000	DISCOUNT %	10.00	10.00	1803.727
GROSS CUM., MB & MMF	.000	.000	UNDISCOUNTED PAYOUT, YRS.	5.71	15.00	1279.184
GROSS RES., MB & MMF	100.000	50.000	DISCOUNTED PAYOUT, YRS.	5.71	20.00	924.020
NET RES., MB & MMF	64.798	32.399	UNDISCOUNTED NET/INVEST.	95.18	25.00	678.547
NET REVENUE, M$	4160.023	249.472	DISCOUNTED NET/INVEST.	79.66	30.00	505.730
INITIAL PRICE, $	64.200	7.700	RATE-OF-RETURN, PCT.	100.00	40.00	292.119
INITIAL N.I., PCT.	64.798	64.798	INITIAL W.I., PCT.	81.250	50.00	176.460
FINAL N.I., PCT.	64.798	64.798	FINAL W.I., PCT.	81.250	75.00	58.374
					100.00	22.799

LAROSA FIELD
PROVED UNDEVELOPED

FLAT PRICE CASE

DATE : 06/22/07
TIME : 00:00:02
DBS FILE : LAROSA
SETUP FILE : QUA
SEQ NUMBER : *****

R E S E R V E S A N D E C O N O M I C S

AS OF DATE: 5/07

-END- MO-YR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-07	31.633	218.143	20.498	141.352	64.200	7.700	1315.955	1088.412	2404.366
12-08	58.400	310.578	37.842	201.248	64.200	7.700	2429.454	1549.611	3979.065
12-09	52.262	181.962	33.864	117.908	64.200	7.700	2174.095	907.888	3081.983
12-10	36.888	95.166	23.902	61.665	64.200	7.700	1534.538	474.824	2009.362
12-11	25.718	36.984	16.665	23.965	64.200	7.700	1069.892	184.532	1254.423
12-12	17.931	8.966	11.619	5.809	64.200	7.700	745.937	44.733	790.670
12-13	12.502	6.251	8.101	4.050	64.200	7.700	520.073	31.188	551.261
12-14	8.716	4.358	5.648	2.824	64.200	7.700	362.599	21.745	384.343
12-15	6.077	3.039	3.938	1.969	64.200	7.700	252.807	15.161	267.967
12-16	3.950	1.975	2.559	1.280	64.200	7.700	164.300	9.853	174.153
12-17	16.881	8.441	10.939	5.469	64.200	7.700	702.264	42.114	744.378
12-18	17.008	8.504	11.021	5.510	64.200	7.700	707.538	42.430	749.968
12-19	13.259	6.629	8.591	4.296	64.200	7.700	551.572	33.077	584.650
12-20	10.246	5.123	6.639	3.319	64.200	7.700	426.222	25.560	451.782
12-21	7.917	3.959	5.130	2.565	64.200	7.700	329.359	19.751	349.110
S TOT	319.388	900.077	206.956	583.231	64.200	7.700	13286.600	4490.878	17777.480
AFTER	19.967	9.984	12.938	6.469	64.200	7.700	830.640	49.813	880.452
TOTAL	339.355	910.061	219.895	589.700	64.200	7.700	14117.240	4540.690	18657.930

-END- MO-YR	NET ADVAL & PROD. TAXES -----M$----	DIRECT OPER EXPENSE -----M$----	SALVAGE VALUE -----M$----	ABANDON COST -----M$----	CAPITAL EXPENSE -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-07	142.165	117.000	.000	.000	1056.250	1088.951	1088.951	1034.909
12-08	227.976	219.375	.000	.000	.000	3531.715	4620.666	4201.247
12-09	168.100	219.375	.000	.000	.000	2694.508	7315.174	6400.899
12-10	106.201	193.781	.000	.000	.000	1709.380	9024.554	7670.221
12-11	63.055	131.625	.000	.000	.000	1059.743	10084.300	8385.314
12-12	37.668	87.750	.000	.000	.000	665.252	10749.550	8793.333
12-13	26.262	87.750	.000	.000	.000	437.249	11186.800	9037.179
12-14	18.310	87.750	.000	.000	.000	278.283	11465.080	9178.310
12-15	12.766	87.750	.000	.000	.000	167.451	11632.530	9255.558
12-16	8.297	80.438	.000	.000	.000	85.419	11717.950	9291.515
12-17	35.463	43.875	.000	.000	40.625	624.415	12342.370	9526.837
12-18	35.729	43.875	.000	.000	.000	670.364	13012.730	9758.598
12-19	27.853	43.875	.000	.000	.000	512.921	13525.650	9919.870
12-20	21.523	43.875	.000	.000	.000	386.384	13912.040	10030.320
12-21	16.632	43.875	.000	.000	.000	288.603	14200.640	10105.320
S TOT	948.000	1531.969	.000	.000	1096.875	14200.640	14200.640	10105.320
AFTER	41.945	230.344	.000	.000	.000	608.163	14808.800	10232.560
TOTAL	989.945	1762.313	.000	.000	1096.875	14808.800	14808.800	10232.560

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	3.0	3.0	LIFE, YRS.	19.92	8.00	10874.420
GROSS ULT., MB & MMF	339.355	957.477	DISCOUNT %	10.00	10.00	10232.560
GROSS CUM., MB & MMF	.000	47.416	UNDISCOUNTED PAYOUT, YRS.	.33	15.00	8961.834
GROSS RES., MB & MMF	339.355	910.061	DISCOUNTED PAYOUT, YRS.	.33	20.00	8015.870
NET RES., MB & MMF	219.895	589.700	UNDISCOUNTED NET/INVEST.	14.50	25.00	7278.969
NET REVENUE, M$	14117.240	4540.690	DISCOUNTED NET/INVEST.	10.73	30.00	6684.480
INITIAL PRICE, $	64.200	7.700	RATE-OF-RETURN, PCT.	100.00	40.00	5774.858
INITIAL N.I., PCT.	64.798	64.798	INITIAL W.I., PCT.	81.250	50.00	5103.580
FINAL N.I., PCT.	64.798	64.798	FINAL W.I., PCT.	81.250	75.00	3987.339
					100.00	3294.051

LAROSA FIELD
PROBABLE

FLAT PRICE CASE

DATE : 06/22/07
TIME : 00:00:04
DBS FILE : LAROSA
SETUP FILE : QUA
SEQ NUMBER : *****

R E S E R V E S A N D E C O N O M I C S

AS OF DATE: 5/07

-END- MO-YR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-07	.000	.000	.000	.000	.000	.000	.000	.000	.000
12-08	48.328	862.533	31.315	558.903	64.200	7.700	2010.448	4303.553	6314.000
12-09	241.840	3470.646	156.707	2248.906	64.200	7.700	10060.600	17316.570	27377.170
12-10	305.947	4368.110	198.247	2830.444	64.200	7.700	12727.450	21794.420	34521.860
12-11	238.389	3158.261	154.471	2046.486	64.200	7.700	9917.062	15757.940	25675.000
12-12	185.960	2293.667	120.498	1486.248	64.200	7.700	7735.966	11444.110	19180.080
12-13	147.869	1694.377	95.816	1097.921	64.200	7.700	6151.388	8453.989	14605.380
12-14	117.855	1269.396	76.367	822.542	64.200	7.700	4902.789	6333.571	11236.360
12-15	94.142	960.958	61.002	622.681	64.200	7.700	3916.314	4794.642	8710.956
12-16	71.560	730.082	46.369	473.077	64.200	7.700	2976.909	3642.696	6619.605
12-17	52.249	539.193	33.856	349.386	64.200	7.700	2173.585	2690.271	4863.855
12-18	42.134	388.006	27.302	251.420	64.200	7.700	1752.773	1935.930	3688.703
12-19	34.261	294.668	22.200	190.939	64.200	7.700	1425.261	1470.229	2895.490
12-20	24.609	212.956	15.946	137.991	64.200	7.700	1023.750	1062.530	2086.280
12-21	15.644	166.094	10.137	107.625	64.200	7.700	650.805	828.715	1479.519
S TOT	1620.786	20408.950	1050.235	13224.570	64.200	7.700	67425.100	101829.200	169254.300
AFTER	26.544	245.254	17.200	158.919	64.200	7.700	1104.247	1223.678	2327.925
TOTAL	1647.330	20654.200	1067.435	13383.490	64.200	7.700	68529.350	103052.800	171582.200

-END- MO-YR	NET ADVAL & PROD. TAXES -----M$----	DIRECT OPER EXPENSE -----M$----	SALVAGE VALUE -----M$----	ABANDON COST -----M$----	CAPITAL EXPENSE -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-07	.000	.000	.000	.000	.000	.000	.000	.000
12-08	415.247	285.188	.000	.000	6825.000	-1211.434	-1211.434	-1136.541
12-09	1761.530	1126.125	.000	.000	10968.750	13520.770	12309.340	9820.598
12-10	2220.044	1491.750	.000	.000	.000	30810.080	43119.420	32669.650
12-11	1638.030	1466.156	.000	.000	.000	22570.820	65690.230	47885.160
12-12	1214.163	1308.938	.000	.000	.000	16656.980	82347.210	58091.850
12-13	917.013	1180.969	.000	.000	.000	12507.400	94854.600	65058.560
12-14	700.546	1096.875	.000	.000	.000	9438.938	104293.500	69838.000
12-15	539.749	1049.344	.000	.000	.000	7121.864	111415.400	73116.620
12-16	410.140	925.031	.000	.000	.000	5284.434	116699.800	75328.740
12-17	301.755	727.594	.000	.000	.000	3834.507	120534.300	76788.120
12-18	225.822	621.563	.000	.000	.000	2841.319	123375.700	77770.860
12-19	175.829	592.313	.000	.000	.000	2127.348	125503.000	78439.900
12-20	126.782	471.656	.000	.000	.000	1487.841	126990.800	78865.730
12-21	92.091	351.000	.000	.000	.000	1036.429	128027.300	79135.050
S TOT	10738.740	12694.500	.000	.000	17793.750	128027.300	128027.300	79135.050
AFTER	142.571	775.125	.000	.000	.000	1410.228	129437.500	79453.660
TOTAL	10881.310	13469.630	.000	.000	17793.750	129437.500	129437.500	79453.660

	OIL	GAS
GROSS WELLS	12.0	22.0
GROSS ULT., MB & MMF	1647.330	20654.200
GROSS CUM., MB & MMF	.000	.000
GROSS RES., MB & MMF	1647.330	20654.200
NET RES., MB & MMF	1067.435	13383.490
NET REVENUE, M$	68529.350	103052.800
INITIAL PRICE, $	64.200	7.700
INITIAL N.I., PCT.	64.798	64.798
FINAL N.I., PCT.	64.798	64.798

LIFE, YRS.	17.08
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	1.76
DISCOUNTED PAYOUT, YRS.	1.77
UNDISCOUNTED NET/INVEST.	8.27
DISCOUNTED NET/INVEST.	6.33
RATE-OF-RETURN, PCT.	100.00
INITIAL W.I., PCT.	81.250
FINAL W.I., PCT.	81.250

P.W. %	P.W., M$
8.00	86870.550
10.00	79453.650
15.00	64505.620
20.00	53317.040
25.00	44730.340
30.00	38000.860
40.00	28283.570
50.00	21750.540
75.00	12485.370
100.00	7914.803

LAROSA FIELD
POSSIBLE

FLAT PRICE CASE

DATE : 06/22/07
TIME : 00:00:04
DBS FILE : LAROSA
SETUP FILE : QUA
SEQ NUMBER : *****

R E S E R V E S A N D E C O N O M I C S

AS OF DATE: 5/07

-END- MO-YR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-07	.000	.000	.000	.000	.000	.000	.000	.000	.000
12-08	.000	.000	.000	.000	.000	.000	.000	.000	.000
12-09	.000	.000	.000	.000	.000	.000	.000	.000	.000
12-10	37.094	1854.722	24.036	1201.820	64.200	7.700	1543.137	9254.016	10797.150
12-11	38.785	1939.229	25.132	1256.580	64.200	7.700	1613.449	9675.665	11289.110
12-12	33.313	1665.637	21.586	1079.298	64.200	7.700	1385.818	8310.590	9696.407
12-13	28.613	1430.643	18.541	927.027	64.200	7.700	1190.302	7138.105	8328.407
12-14	24.576	1228.803	15.925	796.239	64.200	7.700	1022.371	6131.038	7153.409
12-15	21.109	1055.440	13.678	683.903	64.200	7.700	878.131	5266.051	6144.182
12-16	18.131	906.535	11.748	587.416	64.200	7.700	754.242	4523.100	5277.341
12-17	15.573	778.638	10.091	504.541	64.200	7.700	647.831	3884.966	4532.797
12-18	13.376	668.785	8.667	433.359	64.200	7.700	556.433	3336.862	3893.295
12-19	11.489	574.431	7.444	372.219	64.200	7.700	477.929	2866.087	3344.016
12-20	9.868	493.388	6.394	319.705	64.200	7.700	410.501	2461.730	2872.232
12-21	8.476	423.779	5.492	274.600	64.200	7.700	352.587	2114.421	2467.007
S TOT	260.401	13020.030	168.734	8436.705	64.200	7.700	10832.730	64962.630	75795.360
AFTER	39.588	1979.386	25.652	1282.600	64.200	7.700	1646.859	9876.024	11522.880
TOTAL	299.988	14999.420	194.386	9719.305	64.200	7.700	12479.590	74838.660	87318.240

-END- MO-YR	NET ADVAL & PROD. TAXES -----M$----	DIRECT OPER EXPENSE -----M$----	SALVAGE VALUE -----M$----	ABANDON COST -----M$----	CAPITAL EXPENSE -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-07	.000	.000	.000	.000	.000	.000	.000	.000
12-08	.000	.000	.000	.000	.000	.000	.000	.000
12-09	.000	.000	.000	.000	1137.500	-1137.500	-1137.500	-889.243
12-10	765.036	182.813	.000	.000	4550.000	5299.307	4161.807	2863.246
12-11	799.893	219.375	.000	.000	.000	10269.850	14431.650	9778.198
12-12	687.042	219.375	.000	.000	.000	8789.991	23221.640	15158.700
12-13	590.112	219.375	.000	.000	.000	7518.920	30740.560	19342.770
12-14	506.857	219.375	.000	.000	.000	6427.177	37167.740	22594.200
12-15	435.348	219.375	.000	.000	.000	5489.459	42657.200	25118.810
12-16	373.928	219.375	.000	.000	.000	4684.039	47341.240	27077.180
12-17	321.173	219.375	.000	.000	.000	3992.249	51333.490	28594.590
12-18	275.861	219.375	.000	.000	.000	3398.059	54731.550	29768.760
12-19	236.941	219.375	.000	.000	.000	2887.700	57619.250	30675.880
12-20	203.513	219.375	.000	.000	.000	2449.344	60068.590	31375.360
12-21	174.801	219.375	.000	.000	.000	2072.832	62141.420	31913.510
S TOT	5370.503	2595.938	.000	.000	5687.500	62141.420	62141.420	31913.510
AFTER	816.457	2102.344	.000	.000	.000	8604.080	70745.510	33494.880
TOTAL	6186.960	4698.281	.000	.000	5687.500	70745.500	70745.510	33494.880

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	.0	5.0	LIFE, YRS.	24.42	8.00	38264.370
GROSS ULT., MB & MMF	299.988	14999.420	DISCOUNT %	10.00	10.00	33494.880
GROSS CUM., MB & MMF	.000	.000	UNDISCOUNTED PAYOUT, YRS.	2.88	15.00	24662.780
GROSS RES., MB & MMF	299.988	14999.420	DISCOUNTED PAYOUT, YRS.	2.90	20.00	18730.670
NET RES., MB & MMF	194.386	9719.306	UNDISCOUNTED NET/INVEST.	13.44	25.00	14575.340
NET REVENUE, M$	12479.590	74838.660	DISCOUNTED NET/INVEST.	8.65	30.00	11565.950
INITIAL PRICE, $	64.200	7.700	RATE-OF-RETURN, PCT.	100.00	40.00	7623.933
INITIAL N.I., PCT.	64.798	64.798	INITIAL W.I., PCT.	81.250	50.00	5265.370
FINAL N.I., PCT.	64.798	64.798	FINAL W.I., PCT.	81.250	75.00	2397.131
					100.00	1244.094

LAROSA FIELD
GRAND TOTAL
PDP+PDNP+PUD+PROB+POSS

FORCAST PRICE CASE

DATE : 06/21/07
TIME : 23:52:59
DBS FILE : LAROSA
SETUP FILE : QUA
SEQ NUMBER : *****

R E S E R V E S A N D E C O N O M I C S

AS OF DATE: 5/07

-END- MO-YR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-07	43.105	357.202	27.931	231.459	66.700	7.440	1863.001	1722.057	3585.058
12-08	119.817	1339.205	77.639	867.777	64.100	7.380	4976.663	6404.193	11380.860
12-09	303.640	3770.332	196.752	2443.096	60.900	6.790	11982.210	16588.620	28570.830
12-10	387.006	6388.606	250.772	4139.683	57.500	6.470	14419.390	26783.740	41203.120
12-11	308.246	5181.072	199.737	3357.226	54.300	5.990	10845.710	20109.780	30955.490
12-12	241.332	3996.999	156.378	2589.971	51.700	5.820	8084.755	15073.630	23158.390
12-13	219.586	3170.688	142.287	2054.539	50.000	5.650	7114.363	11608.150	18722.510
12-14	179.084	2539.971	116.042	1645.848	49.600	5.680	5755.705	9348.414	15104.120
12-15	140.089	2051.759	90.775	1329.497	49.900	5.620	4529.653	7471.773	12001.430
12-16	105.525	1667.386	68.378	1080.431	49.900	5.620	3412.064	6072.021	9484.085
12-17	92.115	1350.522	59.688	875.110	49.900	5.620	2978.453	4918.117	7896.570
12-18	77.388	1089.813	50.146	706.176	49.900	5.620	2502.286	3968.709	6470.994
12-19	62.210	898.894	40.310	582.464	49.900	5.620	2011.494	3273.450	5284.943
12-20	46.512	733.421	30.139	475.241	49.900	5.620	1503.935	2670.856	4174.791
12-21	32.037	614.397	20.759	398.116	49.900	5.620	1035.891	2237.414	3273.306
S TOT	2357.692	35150.260	1527.735	22776.630	54.339	6.070	83015.580	138250.900	221266.500
AFTER	85.815	2542.188	55.607	1647.284	49.900	5.620	2774.765	9257.737	12032.500
TOTAL	2443.507	37692.450	1583.341	24423.920	54.183	6.040	85790.340	147508.700	233299.000

-END- MO-YR	NET ADVAL & PROD. TAXES -----M$----	DIRECT OPER EXPENSE -----M$----	SALVAGE VALUE -----M$----	ABANDON COST -----M$----	CAPITAL EXPENSE -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-07	214.852	351.000	.000	.000	1056.250	1962.955	1962.955	1882.722
12-08	709.241	855.563	.000	.000	6825.000	2991.052	4954.008	4518.597
12-09	1795.328	1656.281	.000	.000	12106.250	13012.970	17966.970	15115.890
12-10	2672.072	2087.719	.000	.000	4550.000	31893.340	49860.310	38602.600
12-11	2007.137	1996.313	.000	.000	.000	26952.040	76812.350	56766.230
12-12	1502.421	1751.344	.000	.000	.000	19904.620	96716.980	68959.300
12-13	1197.872	1619.719	.000	.000	40.625	15864.290	112581.300	77786.690
12-14	965.894	1535.625	.000	.000	.000	12602.600	125183.900	84166.890
12-15	768.747	1488.094	.000	.000	.000	9744.584	134928.400	88651.750
12-16	612.357	1330.875	.000	.000	.000	7540.853	142469.300	91807.100
12-17	505.868	1071.281	.000	.000	40.625	6278.796	148748.100	94193.460
12-18	412.758	972.563	.000	.000	.000	5085.674	153833.800	95951.770
12-19	338.037	943.313	.000	.000	.000	4003.594	157837.400	97210.240
12-20	269.495	815.344	.000	.000	.000	3089.953	160927.300	98093.470
12-21	215.457	658.125	.000	.000	.000	2399.724	163327.100	98716.780
S TOT	14187.540	19133.160	.000	.000	24618.750	163327.100	163327.100	98716.780
AFTER	821.969	3919.500	.000	.000	.000	7291.033	170618.000	100110.500
TOTAL	15009.500	23052.660	.000	.000	24618.750	170618.100	170618.000	100110.500

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	18.0	36.0	LIFE, YRS.	33.42	8.00	110066.300
GROSS ULT., MB & MMF	2608.124	39132.310	DISCOUNT %	10.00	10.00	100110.400
GROSS CUM., MB & MMF	164.617	1439.861	UNDISCOUNTED PAYOUT, YRS.	.23	15.00	80545.620
GROSS RES., MB & MMF	2443.507	37692.450	DISCOUNTED PAYOUT, YRS.	.24	20.00	66319.580
NET RES., MB & MMF	1583.341	24423.920	UNDISCOUNTED NET/INVEST.	7.93	25.00	55631.550
NET REVENUE, M$	85790.340	147508.700	DISCOUNTED NET/INVEST.	5.92	30.00	47387.570
INITIAL PRICE, $	58.628	6.747	RATE-OF-RETURN, PCT.	100.00	40.00	35675.470
INITIAL N.I., PCT.	64.798	64.798	INITIAL W.I., PCT.	81.250	50.00	27916.840
FINAL N.I., PCT.	64.798	64.798	FINAL W.I., PCT.	81.250	75.00	17032.170
					100.00	11670.350

LAROSA FIELD
TOTAL PROVED
PDP+PDNP+PUD

FORCAST PRICE CASE

DATE : 06/21/07
TIME : 23:52:59
DBS FILE : LAROSA
SETUP FILE : QUA
SEQ NUMBER : *****

R E S E R V E S A N D E C O N O M I C S

AS OF DATE: 5/07

-END- MO-YR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-07	43.105	357.202	27.931	231.459	66.700	7.440	1863.001	1722.057	3585.058
12-08	71.489	476.672	46.324	308.874	64.100	7.380	2969.348	2279.488	5248.835
12-09	61.800	299.686	40.045	194.190	60.900	6.790	2438.735	1318.550	3757.286
12-10	43.965	165.774	28.489	107.418	57.500	6.470	1638.097	694.996	2333.092
12-11	31.072	84.460	20.134	54.728	54.300	5.990	1093.272	327.823	1421.095
12-12	22.060	38.516	14.294	24.957	51.700	5.820	739.019	145.251	884.271
12-13	43.104	45.668	27.931	29.592	50.000	5.650	1396.536	167.195	1563.731
12-14	36.653	41.772	23.750	27.067	49.600	5.680	1178.012	153.742	1331.754
12-15	24.838	35.361	16.095	22.913	49.900	5.620	803.129	128.773	931.902
12-16	15.834	30.769	10.260	19.938	49.900	5.620	511.995	112.051	624.045
12-17	24.293	34.759	15.741	22.523	49.900	5.620	785.484	126.581	912.065
12-18	21.879	33.022	14.177	21.398	49.900	5.620	707.436	120.255	827.691
12-19	16.460	29.795	10.666	19.306	49.900	5.620	532.223	108.502	640.725
12-20	12.035	27.077	7.799	17.545	49.900	5.620	389.151	98.604	487.755
12-21	7.917	24.524	5.130	15.891	49.900	5.620	255.997	89.308	345.304
S TOT	476.505	1725.058	308.766	1117.801	56.034	6.793	17301.430	7593.177	24894.610
AFTER	19.967	317.548	12.938	205.765	49.900	5.620	645.622	1156.397	1802.019
TOTAL	496.473	2042.606	321.704	1323.566	55.788	6.611	17947.050	8749.574	26696.630

-END- MO-YR	NET ADVAL & PROD. TAXES -----M$----	DIRECT OPER EXPENSE -----M$----	SALVAGE VALUE -----M$----	ABANDON COST -----M$----	CAPITAL EXPENSE -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-07	214.852	351.000	.000	.000	1056.250	1962.955	1962.955	1882.722
12-08	307.552	570.375	.000	.000	.000	4370.909	6333.864	5802.585
12-09	211.073	530.156	.000	.000	.000	3016.056	9349.920	8264.935
12-10	127.477	413.156	.000	.000	.000	1792.459	11142.380	9595.862
12-11	74.877	314.438	.000	.000	.000	1031.780	12174.160	10292.170
12-12	44.889	226.688	.000	.000	.000	612.695	12786.850	10667.980
12-13	76.780	219.375	.000	.000	40.625	1226.951	14013.800	11344.910
12-14	65.719	219.375	.000	.000	.000	1046.660	15060.460	11875.600
12-15	46.602	219.375	.000	.000	.000	665.925	15726.390	12182.610
12-16	31.956	186.469	.000	.000	.000	405.621	16132.010	12352.710
12-17	45.626	131.625	.000	.000	40.625	694.189	16826.200	12615.040
12-18	41.561	131.625	.000	.000	.000	654.505	17480.700	12841.420
12-19	32.620	131.625	.000	.000	.000	476.480	17957.180	12991.290
12-20	25.296	124.313	.000	.000	.000	338.146	18295.330	13088.020
12-21	18.474	87.750	.000	.000	.000	239.080	18534.410	13150.150
S TOT	1365.354	3857.344	.000	.000	1137.500	18534.410	18534.410	13150.150
AFTER	116.428	1053.000	.000	.000	.000	632.591	19167.000	13270.770
TOTAL	1481.782	4910.344	.000	.000	1137.500	19167.000	19167.000	13270.770

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	6.0	9.0	LIFE, YRS.	33.42	8.00	14105.200
GROSS ULT., MB & MMF	661.090	3482.467	DISCOUNT %	10.00	10.00	13270.770
GROSS CUM., MB & MMF	164.617	1439.861	UNDISCOUNTED PAYOUT, YRS.	.23	15.00	11615.040
GROSS RES., MB & MMF	496.473	2042.606	DISCOUNTED PAYOUT, YRS.	.24	20.00	10384.330
NET RES., MB & MMF	321.704	1323.566	UNDISCOUNTED NET/INVEST.	17.85	25.00	9431.515
NET REVENUE, M$	17947.050	8749.574	DISCOUNTED NET/INVEST.	13.34	30.00	8669.545
INITIAL PRICE, $	48.724	4.636	RATE-OF-RETURN, PCT.	100.00	40.00	7519.964
INITIAL N.I., PCT.	64.798	64.798	INITIAL W.I., PCT.	81.250	50.00	6686.344
FINAL N.I., PCT.	64.798	64.798	FINAL W.I., PCT.	81.250	75.00	5325.518
					100.00	4489.555

LAROSA FIELD
PROVED PRODUCING

FORCAST PRICE CASE

DATE : 06/21/07
TIME : 23:52:55
DBS FILE : LAROSA
SETUP FILE : QUA
SEQ NUMBER : *****

R E S E R V E S A N D E C O N O M I C S

AS OF DATE: 5/07

-END- MO-YR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-07	11.472	139.059	7.433	90.107	66.700	7.440	495.802	670.397	1166.199
12-08	13.089	166.094	8.482	107.626	64.100	7.380	543.677	794.277	1337.953
12-09	9.538	117.724	6.181	76.282	60.900	6.790	376.393	517.958	894.351
12-10	7.078	70.608	4.586	45.753	57.500	6.470	263.705	296.020	559.725
12-11	5.353	47.476	3.469	30.763	54.300	5.990	188.364	184.272	372.635
12-12	4.129	29.550	2.675	19.148	51.700	5.820	138.320	111.440	249.760
12-13	2.421	25.327	1.569	16.411	50.000	5.650	78.438	92.723	171.161
12-14	1.828	24.359	1.184	15.784	49.600	5.680	58.739	89.655	148.394
12-15	1.602	23.743	1.038	15.385	49.900	5.620	51.809	86.465	138.273
12-16	.608	23.156	.394	15.005	49.900	5.620	19.654	84.326	103.980
12-17	.000	22.613	.000	14.653	.000	5.620	.000	82.348	82.348
12-18	.000	22.083	.000	14.309	.000	5.620	.000	80.417	80.417
12-19	.000	21.565	.000	13.974	.000	5.620	.000	78.532	78.532
12-20	.000	21.059	.000	13.646	.000	5.620	.000	76.690	76.690
12-21	.000	20.565	.000	13.326	.000	5.620	.000	74.892	74.892
S TOT	57.118	774.981	37.011	502.171	59.844	6.612	2214.901	3320.410	5535.310
AFTER	.000	307.565	.000	199.295	.000	5.620	.000	1120.041	1120.041
TOTAL	57.118	1082.546	37.011	701.467	59.844	6.330	2214.901	4440.451	6655.351

-END- MO-YR	NET ADVAL & PROD. TAXES -----M$----	DIRECT OPER EXPENSE -----M$----	SALVAGE VALUE -----M$----	ABANDON COST -----M$----	CAPITAL EXPENSE -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-07	73.087	234.000	.000	.000	.000	859.112	859.112	833.514
12-08	84.580	351.000	.000	.000	.000	902.373	1761.485	1643.805
12-09	56.161	310.781	.000	.000	.000	527.409	2288.894	2074.579
12-10	34.332	219.375	.000	.000	.000	306.018	2594.912	2301.762
12-11	22.485	182.813	.000	.000	.000	167.338	2762.250	2414.719
12-12	14.721	138.938	.000	.000	.000	96.102	2858.352	2473.659
12-13	10.562	98.719	.000	.000	.000	61.880	2920.231	2508.110
12-14	9.426	87.750	.000	.000	.000	51.218	2971.449	2534.026
12-15	8.868	87.750	.000	.000	.000	41.655	3013.104	2553.191
12-16	7.229	62.156	.000	.000	.000	34.595	3047.700	2567.650
12-17	6.176	43.875	.000	.000	.000	32.297	3079.997	2579.915
12-18	6.031	43.875	.000	.000	.000	30.511	3110.508	2590.450
12-19	5.890	43.875	.000	.000	.000	28.767	3139.275	2599.479
12-20	5.752	43.875	.000	.000	.000	27.063	3166.338	2607.201
12-21	5.617	43.875	.000	.000	.000	25.400	3191.738	2613.790
S TOT	350.916	1992.656	.000	.000	.000	3191.738	3191.738	2613.790
AFTER	84.003	822.656	.000	.000	.000	213.381	3405.119	2645.941
TOTAL	434.919	2815.313	.000	.000	.000	3405.119	3405.119	2645.941

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	2.0	6.0	LIFE, YRS.	33.42	8.00	2751.191
GROSS ULT., MB & MMF	221.735	2474.990	DISCOUNT %	10.00	10.00	2645.941
GROSS CUM., MB & MMF	164.617	1392.445	UNDISCOUNTED PAYOUT, YRS.	.00	15.00	2432.866
GROSS RES., MB & MMF	57.118	1082.546	DISCOUNTED PAYOUT, YRS.	.00	20.00	2267.256
NET RES., MB & MMF	37.011	701.467	UNDISCOUNTED NET/INVEST.	.00	25.00	2132.413
NET REVENUE, M$	2214.901	4440.451	DISCOUNTED NET/INVEST.	.00	30.00	2019.236
INITIAL PRICE, $	.000	.000	RATE-OF-RETURN, PCT.	100.00	40.00	1837.739
INITIAL N.I., PCT.	64.798	64.798	INITIAL W.I., PCT.	.000	50.00	1697.048
FINAL N.I., PCT.	64.798	64.798	FINAL W.I., PCT.	81.250	75.00	1449.788
					100.00	1286.902

LAROSA FIELD
PROVED NON PRODUCING

FORCAST PRICE CASE

DATE : 06/21/07
TIME : 23:52:55
DBS FILE : LAROSA
SETUP FILE : QUA
SEQ NUMBER : *****

R E S E R V E S A N D E C O N O M I C S

AS OF DATE: 5/07

-END- MO-YR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-07	.000	.000	.000	.000	.000	.000	.000	.000	.000
12-08	.000	.000	.000	.000	.000	.000	.000	.000	.000
12-09	.000	.000	.000	.000	.000	.000	.000	.000	.000
12-10	.000	.000	.000	.000	.000	.000	.000	.000	.000
12-11	.000	.000	.000	.000	.000	.000	.000	.000	.000
12-12	.000	.000	.000	.000	.000	.000	.000	.000	.000
12-13	28.182	14.091	18.261	9.131	50.000	5.650	913.056	51.588	964.644
12-14	26.109	13.054	16.918	8.459	49.600	5.680	839.134	48.047	887.181
12-15	17.159	8.580	11.119	5.559	49.900	5.620	554.824	31.244	586.068
12-16	11.277	5.639	7.307	3.654	49.900	5.620	364.636	20.534	385.170
12-17	7.411	3.706	4.802	2.401	49.900	5.620	239.643	13.495	253.138
12-18	4.871	2.435	3.156	1.578	49.900	5.620	157.496	8.869	166.365
12-19	3.201	1.601	2.074	1.037	49.900	5.620	103.508	5.829	109.337
12-20	1.790	.895	1.160	.580	49.900	5.620	57.866	3.259	61.125
12-21									
S TOT	100.000	50.000	64.798	32.399	49.850	5.644	3230.165	182.864	3413.028
AFTER	.000	.000	.000	.000	.000	.000	.000	.000	.000
TOTAL	100.000	50.000	64.798	32.399	49.850	5.644	3230.165	182.864	3413.028

-END- MO-YR	NET ADVAL & PROD. TAXES -----M$----	DIRECT OPER EXPENSE -----M$----	SALVAGE VALUE -----M$----	ABANDON COST -----M$----	CAPITAL EXPENSE -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-07	.000	.000	.000	.000	.000	.000	.000	.000
12-08	.000	.000	.000	.000	.000	.000	.000	.000
12-09	.000	.000	.000	.000	.000	.000	.000	.000
12-10	.000	.000	.000	.000	.000	.000	.000	.000
12-11	.000	.000	.000	.000	.000	.000	.000	.000
12-12	.000	.000	.000	.000	.000	.000	.000	.000
12-13	45.870	32.906	.000	.000	40.625	845.243	845.243	464.077
12-14	42.204	43.875	.000	.000	.000	801.103	1646.346	870.252
12-15	27.865	43.875	.000	.000	.000	514.327	2160.673	1107.344
12-16	18.313	43.875	.000	.000	.000	322.982	2483.655	1242.718
12-17	12.036	43.875	.000	.000	.000	197.227	2680.882	1317.890
12-18	7.910	43.875	.000	.000	.000	114.580	2795.462	1357.612
12-19	5.199	43.875	.000	.000	.000	60.263	2855.726	1376.626
12-20	2.906	36.563	.000	.000	.000	21.656	2877.382	1382.897
12-21								
S TOT	162.302	332.719	.000	.000	40.625	2877.382	2877.382	1382.897
AFTER	.000	.000	.000	.000	.000	.000	2877.382	1382.897
TOTAL	162.302	332.719	.000	.000	40.625	2877.382	2877.382	1382.897

	OIL	GAS
GROSS WELLS	1.0	.0
GROSS ULT., MB & MMF	100.000	50.000
GROSS CUM., MB & MMF	.000	.000
GROSS RES., MB & MMF	100.000	50.000
NET RES., MB & MMF	64.798	32.399
NET REVENUE, M$	3230.165	182.864
INITIAL PRICE, $	50.000	5.650
INITIAL N.I., PCT.	64.798	64.798
FINAL N.I., PCT.	64.798	64.798

LIFE, YRS.	13.50
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	5.71
DISCOUNTED PAYOUT, YRS.	5.71
UNDISCOUNTED NET/INVEST.	71.83
DISCOUNTED NET/INVEST.	60.35
RATE-OF-RETURN, PCT.	100.00
INITIAL W.I., PCT.	81.250
FINAL W.I., PCT.	81.250

P.W. %	P.W., M$
8.00	1589.878
10.00	1382.897
15.00	989.224
20.00	720.352
25.00	533.012
30.00	400.118
40.00	234.201
50.00	143.194
75.00	48.633
100.00	19.423

LAROSA FIELD
PROVED UNDEVELOPED

FORCAST PRICE CASE

DATE : 06/21/07
TIME : 23:52:56
DBS FILE : LAROSA
SETUP FILE : QUA
SEQ NUMBER : *****

R E S E R V E S A N D E C O N O M I C S

AS OF DATE: 5/07

-END- MO-YR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-07	31.633	218.143	20.498	141.352	66.700	7.440	1367.199	1051.660	2418.859
12-08	58.400	310.578	37.842	201.248	64.100	7.380	2425.671	1485.211	3910.882
12-09	52.262	181.962	33.864	117.908	60.900	6.790	2062.342	800.592	2862.935
12-10	36.888	95.166	23.902	61.665	57.500	6.470	1374.391	398.976	1773.367
12-11	25.718	36.984	16.665	23.965	54.300	5.990	904.908	143.551	1048.459
12-12	17.931	8.966	11.619	5.809	51.700	5.820	600.700	33.811	634.511
12-13	12.502	6.251	8.101	4.050	50.000	5.650	405.041	22.885	427.926
12-14	8.716	4.358	5.648	2.824	49.600	5.680	280.139	16.040	296.179
12-15	6.077	3.039	3.938	1.969	49.900	5.620	196.496	11.065	207.561
12-16	3.950	1.975	2.559	1.280	49.900	5.620	127.704	7.191	134.895
12-17	16.881	8.441	10.939	5.469	49.900	5.620	545.841	30.738	576.579
12-18	17.008	8.504	11.021	5.510	49.900	5.620	549.940	30.969	580.908
12-19	13.259	6.629	8.591	4.296	49.900	5.620	428.714	24.142	452.856
12-20	10.246	5.123	6.639	3.319	49.900	5.620	331.285	18.656	349.940
12-21	7.917	3.959	5.130	2.565	49.900	5.620	255.997	14.416	270.413
S TOT	319.388	900.077	206.956	583.231	57.289	7.012	11856.370	4089.903	15946.270
AFTER	19.967	9.984	12.938	6.469	49.900	5.620	645.622	36.357	681.978
TOTAL	339.355	910.061	219.895	589.700	56.854	6.997	12501.990	4126.260	16628.250

-END- MO-YR	NET ADVAL & PROD. TAXES -----M$----	DIRECT OPER EXPENSE -----M$----	SALVAGE VALUE -----M$----	ABANDON COST -----M$----	CAPITAL EXPENSE -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-07	141.766	117.000	.000	.000	1056.250	1103.844	1103.844	1049.207
12-08	222.972	219.375	.000	.000	.000	3468.535	4572.379	4158.780
12-09	154.912	219.375	.000	.000	.000	2488.648	7061.027	6190.356
12-10	93.145	193.781	.000	.000	.000	1486.440	8547.467	7294.100
12-11	52.392	131.625	.000	.000	.000	864.442	9411.909	7877.449
12-12	30.168	87.750	.000	.000	.000	516.593	9928.502	8194.326
12-13	20.348	87.750	.000	.000	.000	319.828	10248.330	8372.725
12-14	14.089	87.750	.000	.000	.000	194.339	10442.670	8471.322
12-15	9.869	87.750	.000	.000	.000	109.943	10552.610	8522.080
12-16	6.414	80.438	.000	.000	.000	48.044	10600.660	8542.339
12-17	27.414	43.875	.000	.000	40.625	464.665	11065.320	8717.236
12-18	27.620	43.875	.000	.000	.000	509.414	11574.740	8893.359
12-19	21.532	43.875	.000	.000	.000	387.450	11962.190	9015.187
12-20	16.638	43.875	.000	.000	.000	289.427	12251.610	9097.927
12-21	12.857	43.875	.000	.000	.000	213.681	12465.290	9153.465
S TOT	852.136	1531.969	.000	.000	1096.875	12465.290	12465.290	9153.465
AFTER	32.425	230.344	.000	.000	.000	419.209	12884.500	9241.937
TOTAL	884.561	1762.313	.000	.000	1096.875	12884.500	12884.500	9241.937

	OIL	GAS
GROSS WELLS	3.0	3.0
GROSS ULT., MB & MMF	339.355	957.477
GROSS CUM., MB & MMF	.000	47.416
GROSS RES., MB & MMF	339.355	910.061
NET RES., MB & MMF	219.895	589.700
NET REVENUE, M$	12501.990	4126.259
INITIAL PRICE, $	62.700	7.405
INITIAL N.I., PCT.	64.798	64.798
FINAL N.I., PCT.	64.798	64.798

LIFE, YRS.	19.92
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	.33
DISCOUNTED PAYOUT, YRS.	.33
UNDISCOUNTED NET/INVEST.	12.75
DISCOUNTED NET/INVEST.	9.79
RATE-OF-RETURN, PCT.	100.00
INITIAL W.I., PCT.	81.250
FINAL W.I., PCT.	81.250

P.W. %	P.W., M$
8.00	9764.126
10.00	9241.936
15.00	8192.950
20.00	7396.725
25.00	6766.089
30.00	6250.191
40.00	5448.024
50.00	4846.103
75.00	3827.097
100.00	3183.231

LAROSA FIELD
PROBABLE

FORCAST PRICE CASE

DATE : 06/21/07
TIME : 23:52:58
DBS FILE : LAROSA
SETUP FILE : QUA
SEQ NUMBER : *****

R E S E R V E S A N D E C O N O M I C S

AS OF DATE: 5/07

-END- MO-YR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-07	.000	.000	.000	.000	.000	.000	.000	.000	.000
12-08	48.328	862.533	31.315	558.903	64.100	7.380	2007.316	4124.705	6132.020
12-09	241.840	3470.646	156.707	2248.906	60.900	6.790	9543.470	15270.070	24813.540
12-10	305.947	4368.110	198.247	2830.444	57.500	6.470	11399.200	18312.970	29712.160
12-11	238.389	3157.382	154.471	2045.917	54.300	5.990	8387.796	12255.040	20642.830
12-12	185.960	2292.847	120.498	1485.717	51.700	5.820	6229.742	8646.869	14876.610
12-13	147.869	1694.377	95.816	1097.921	50.000	5.650	4790.801	6203.252	10994.060
12-14	117.855	1269.396	76.367	822.542	49.600	5.680	3787.824	4672.037	8459.861
12-15	94.142	960.958	61.002	622.681	49.900	5.620	3043.989	3499.466	6543.455
12-16	71.560	730.082	46.369	473.077	49.900	5.620	2313.828	2658.695	4972.523
12-17	52.249	537.125	33.856	348.045	49.900	5.620	1689.437	1956.015	3645.452
12-18	42.134	388.006	27.302	251.420	49.900	5.620	1362.358	1412.977	2775.336
12-19	34.261	294.668	22.200	190.939	49.900	5.620	1107.797	1073.076	2180.873
12-20	24.609	212.956	15.946	137.991	49.900	5.620	795.719	775.509	1571.227
12-21	15.644	166.094	10.137	107.625	49.900	5.620	505.844	604.854	1110.698
S TOT	1620.786	20405.180	1050.235	13222.130	54.240	6.161	56965.120	81465.540	138430.700
AFTER	26.260	245.254	17.016	158.919	49.900	5.620	849.108	893.126	1742.234
TOTAL	1647.046	20650.430	1067.252	13381.050	54.171	6.155	57814.220	82358.670	140172.900

-END- MO-YR	NET ADVAL & PROD. TAXES -----M$----	DIRECT OPER EXPENSE -----M$----	SALVAGE VALUE -----M$----	ABANDON COST -----M$----	CAPITAL EXPENSE -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-07	.000	.000	.000	.000	.000	.000	.000	.000
12-08	401.689	285.188	.000	.000	6825.000	-1379.856	-1379.856	-1283.988
12-09	1584.255	1126.125	.000	.000	10968.750	11134.410	9754.554	7740.202
12-10	1897.836	1491.750	.000	.000	.000	26322.580	36077.140	27261.480
12-11	1304.967	1462.500	.000	.000	.000	17875.370	53952.510	39311.930
12-12	935.083	1305.281	.000	.000	.000	12636.250	66588.750	47055.090
12-13	685.621	1180.969	.000	.000	.000	9127.462	75716.220	52139.420
12-14	524.643	1096.875	.000	.000	.000	6838.343	82554.560	55602.320
12-15	402.483	1049.344	.000	.000	.000	5091.627	87646.180	57946.500
12-16	305.838	925.031	.000	.000	.000	3741.654	91387.840	59512.890
12-17	224.415	720.281	.000	.000	.000	2700.756	94088.590	60540.760
12-18	168.642	621.563	.000	.000	.000	1985.131	96073.720	61227.450
12-19	131.439	592.313	.000	.000	.000	1457.121	97530.840	61685.780
12-20	94.766	471.656	.000	.000	.000	1004.805	98535.650	61973.340
12-21	68.633	351.000	.000	.000	.000	691.065	99226.710	62152.970
S TOT	8730.310	12679.870	.000	.000	17793.750	99226.710	99226.710	62152.970
AFTER	106.043	764.156	.000	.000	.000	872.034	100098.700	62350.480
TOTAL	8836.353	13444.030	.000	.000	17793.750	100098.700	100098.700	62350.480

	OIL	GAS
GROSS WELLS	12.0	22.0
GROSS ULT., MB & MMF	1647.046	20650.430
GROSS CUM., MB & MMF	.000	.000
GROSS RES., MB & MMF	1647.046	20650.430
NET RES., MB & MMF	1067.251	13381.050
NET REVENUE, M$	57814.230	82358.670
INITIAL PRICE, $	62.148	7.087
INITIAL N.I., PCT.	64.798	64.798
FINAL N.I., PCT.	64.798	64.798

LIFE, YRS.	17.00
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	1.79
DISCOUNTED PAYOUT, YRS.	1.81
UNDISCOUNTED NET/INVEST.	6.63
DISCOUNTED NET/INVEST.	5.19
RATE-OF-RETURN, PCT.	100.00
INITIAL W.I., PCT.	81.250
FINAL W.I., PCT.	81.250

P.W. %	P.W., M$
8.00	68004.370
10.00	62350.470
15.00	50887.660
20.00	42240.750
25.00	35560.180
30.00	30294.240
40.00	22637.430
50.00	17450.050
75.00	10030.230
100.00	6340.049

LAROSA FIELD
POSSIBLE

FORCAST PRICE CASE

DATE : 06/21/07
TIME : 23:52:59
DBS FILE : LAROSA
SETUP FILE : QUA
SEQ NUMBER : *****

R E S E R V E S A N D E C O N O M I C S

AS OF DATE: 5/07

-END- MO-YR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-07	.000	.000	.000	.000	.000	.000	.000	.000	.000
12-08	.000	.000	.000	.000	.000	.000	.000	.000	.000
12-09	.000	.000	.000	.000	.000	.000	.000	.000	.000
12-10	37.094	1854.722	24.036	1201.820	57.500	6.470	1382.094	7775.778	9157.871
12-11	38.785	1939.229	25.132	1256.580	54.300	5.990	1364.646	7526.912	8891.560
12-12	33.313	1665.637	21.586	1079.298	51.700	5.820	1115.994	6281.511	7397.505
12-13	28.613	1430.643	18.541	927.027	50.000	5.650	927.027	5237.701	6164.727
12-14	24.576	1228.803	15.925	796.239	49.600	5.680	789.869	4522.636	5312.504
12-15	21.109	1055.440	13.678	683.903	49.900	5.620	682.535	3843.533	4526.069
12-16	18.131	906.535	11.748	587.416	49.900	5.620	586.241	3301.275	3887.516
12-17	15.573	778.638	10.091	504.541	49.900	5.620	503.532	2835.520	3339.052
12-18	13.376	668.785	8.667	433.359	49.900	5.620	432.492	2435.476	2867.968
12-19	11.489	574.431	7.444	372.219	49.900	5.620	371.475	2091.871	2463.346
12-20	9.868	493.388	6.394	319.705	49.900	5.620	319.066	1796.743	2115.809
12-21	8.476	423.779	5.492	274.600	49.900	5.620	274.051	1543.252	1817.304
S TOT	260.401	13020.030	168.734	8436.705	51.851	5.831	8749.019	49192.210	57941.230
AFTER	39.588	1979.386	25.652	1282.600	49.900	5.620	1280.035	7208.214	8488.249
TOTAL	299.988	14999.420	194.386	9719.305	51.593	5.803	10029.050	56400.420	66429.480

-END- MO-YR	NET ADVAL & PROD. TAXES -----M$----	DIRECT OPER EXPENSE -----M$----	SALVAGE VALUE -----M$----	ABANDON COST -----M$----	CAPITAL EXPENSE -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-07	.000	.000	.000	.000	.000	.000	.000	.000
12-08	.000	.000	.000	.000	.000	.000	.000	.000
12-09	.000	.000	.000	.000	1137.500	-1137.500	-1137.500	-889.243
12-10	646.760	182.813	.000	.000	4550.000	3778.300	2640.800	1745.257
12-11	627.292	219.375	.000	.000	.000	8044.892	10685.690	7162.128
12-12	522.449	219.375	.000	.000	.000	6655.681	17341.370	11236.220
12-13	435.471	219.375	.000	.000	.000	5509.882	22851.250	14302.360
12-14	375.532	219.375	.000	.000	.000	4717.598	27568.850	16688.970
12-15	319.662	219.375	.000	.000	.000	3987.032	31555.880	18522.640
12-16	274.563	219.375	.000	.000	.000	3393.578	34949.460	19941.510
12-17	235.827	219.375	.000	.000	.000	2883.851	37833.320	21037.660
12-18	202.555	219.375	.000	.000	.000	2446.038	40279.350	21882.890
12-19	173.978	219.375	.000	.000	.000	2069.993	42349.340	22533.160
12-20	149.433	219.375	.000	.000	.000	1747.001	44096.340	23032.090
12-21	128.350	219.375	.000	.000	.000	1469.578	45565.920	23413.650
S TOT	4091.870	2595.938	.000	.000	5687.500	45565.920	45565.920	23413.650
AFTER	599.498	2102.344	.000	.000	.000	5786.408	51352.330	24489.200
TOTAL	4691.368	4698.281	.000	.000	5687.500	51352.330	51352.330	24489.200

	OIL	GAS
GROSS WELLS	.0	5.0
GROSS ULT., MB & MMF	299.988	14999.420
GROSS CUM., MB & MMF	.000	.000
GROSS RES., MB & MMF	299.988	14999.420
NET RES., MB & MMF	194.386	9719.306
NET REVENUE, M$	10029.050	56400.420
INITIAL PRICE, $	57.500	6.470
INITIAL N.I., PCT.	64.798	64.798
FINAL N.I., PCT.	64.798	64.798

LIFE, YRS.	24.42
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	2.97
DISCOUNTED PAYOUT, YRS.	3.00
UNDISCOUNTED NET/INVEST.	10.03
DISCOUNTED NET/INVEST.	6.60
RATE-OF-RETURN, PCT.	100.00
INITIAL W.I., PCT.	81.250
FINAL W.I., PCT.	81.250

P.W. %	P.W., M$
8.00	27956.770
10.00	24489.200
15.00	18042.920
20.00	13694.500
25.00	10639.860
30.00	8423.788
40.00	5518.083
50.00	3780.448
75.00	1676.420
100.00	840.750

C. Geologic and Engineering Risks & Uncertainties

Probability of Geological Success

The Probability of Geological Success (Pg) is the probability of discovering hydrocarbon accumulations that will flow at a sustainable, measurable rate. Pg is estimated by quantifying the probability of each of the following individual geologic factors: trap, source rock, reservoir, seal, and timing of migration. This has been previously addressed in this report. The combined probability, or the product of the five probabilities of the factors that comprise the hydrocarbon system, is computed as Pg.

However, because La Rosa Field has produced from 44 different reservoirs to date, and 151 wells have been drilled in the field since its discovery in 1938, this report will not address geologic risks except to say that the field is comprised of the following:

Traps are variable: faults trap with both antithetic and sympathetic throw; individual sands pinch out, shale out, or are trapped by capillary pressure relationships.

Reservoirs are variable: They may take the form of thin channel sands, to delta front lobes; it is anticipated that deep reservoirs maybe slope or basin floor fans and channels. As a consequence, porosity and permeability is highly variable, as is clay content, grain and pore throat size.

Source rock: No question that a source rock exists, for the field to date has produced over 25 million barrels and 50 BCF of natural gas. As in most of the Gulf Coast, significant hydrocarbons have been generated in the Jurassic and Cretaceous carbonates underlying the Tertiary clastic wedge, but studies suggest that the Midway Shale (Wilcox) and Jackson Shale (Eocene) are viable sources as well.

Seal: The most obvious seals are the contemporaneous and post-depositional faults. Faults with displacement of as little as 30-50 feet may trap sands as thin as 2-5 feet in thickness, or trap an oil or gas column as thick as the amount of shale that is on the opposing side of a fault. Because of the marine to shelf margin to coastal plain to fluvial conditions under which the sands were deposited, and the variable sand thickness produced by the intimate fault and structural relationships, shale barriers, capillary pressure seals and pinch outs are historic and excellent seals at La Rosa.

Charge: The timing of migration in the Frio-Vicksburg trend is ideal. The charge has most likely been by the. pervasive growth fault, and related faults, of this extensional structural system which is discussed in Appendix. The down-thrown, expanded clastic reservoirs had nearly contemporaneous charging of migrating fluids, along with the contemporaneous deposition of clastic reservoirs with concurrent faults.

One objective at La Rosa is to infill drill un-drained, or undepleted fault blocks. Another objective is to target potential gas charged stratigraphic traps utilizing the 3-D seismic data. Deep, gas charged seismic events are abundant and prominently display gas-charged characteristics.

APPENDIX A:
FRIO AND VICKSBURG DEPOSITIONAL SYSTEMS

Evolution of Growth Faulting and Contemporaneous Sedimentation

The depositional systems of clastic sedimentation in the Gulf of Mexico have been virtually the same for the last 65 million years. The depositional series began with an unstable shelf and slope from older clastic sequences. The source of sediment originated in the Rocky Mountains, Sierra Madre Occidental and the Appalachian Mountains (figure 19, 20). Because sediments seek the path of least resistance, a new depocenter shifts in away from an older delta-to-basin bulge; the new sediment is forced to compensate and move to a topographically lower depositional setting (figure 21).

Shifting sea levels always play an important part of the depositional systems. *Regression*, or progradation, occurs during falling sea level, basin subsidence, or increases in sedimentation rates. The falling sea level may be from removal of water from the worlds oceans during glacial advance, or it may be due to tectonic uplift. *Transgression*, or aggradation, occurs during rising sea level, low rates of sedimentation and limited basin subsidence. Sea level rise may be due to periods of glacial melting, and during stable tectonic environments (figures 22-24).

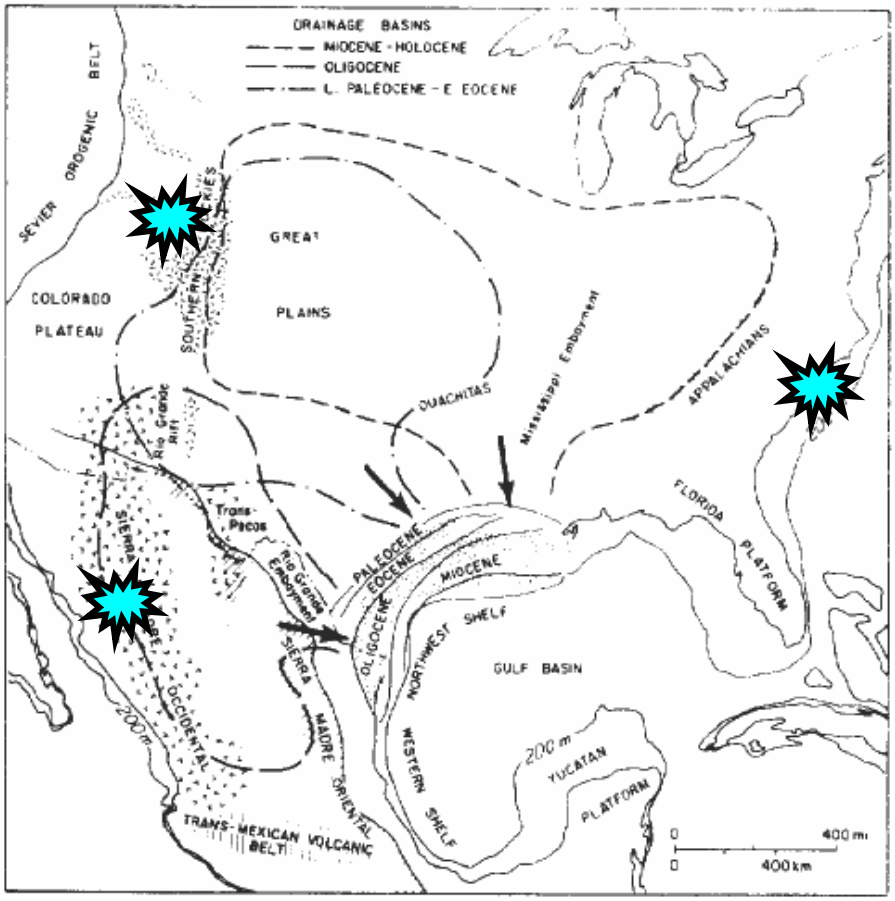


Figure 19, Sediment source areas for the Gulf Coast Sediments is shown as uplifts in the Appalachian, and Rocky Mountains, as well as Mexico's Sierra Madre Occidental,.

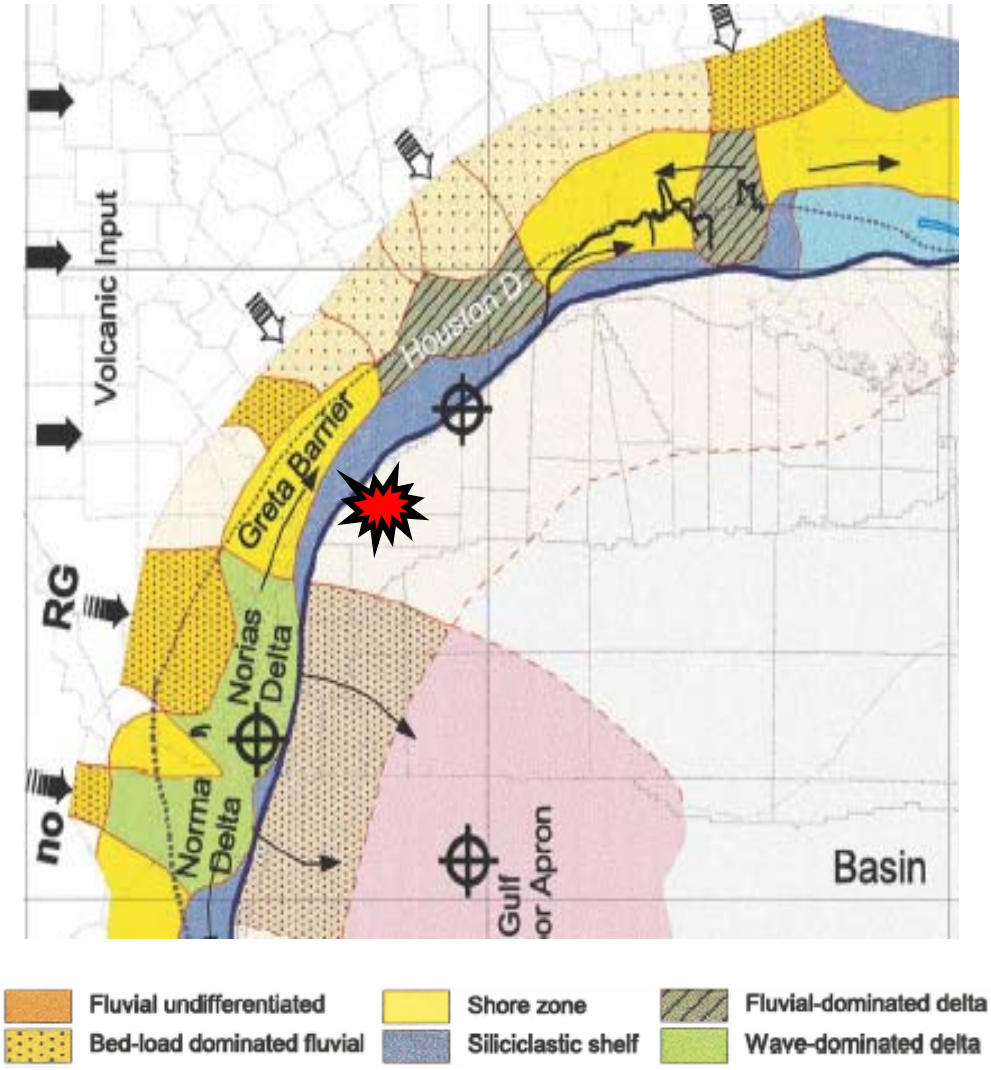


Figure 20, Paleogeography of Oligocene, Vicksburg & Frio

The two systems of greatest importance at La Rosa are the Oligocene-aged Frio and Vicksburg formations. In the Gulf Coast Basin, depositional systems reorganized across (1) major transgressive and high-stand events on the shelf, but at the same time a (2) down-system regressive depositional cycle developed where sediment was distributed onto an unstable mud dominated shelf margin and into a down-system sub-basin. In the case of the older Vicksburg formation, the initial sands would be distributed outward toward the Gulf of Mexico across the underlying and unstable Jackson-Yegua delta-slope systems. The Frio subsequently compensates by shifting deposcenters and builds outward and over the Vicksburg shelf and slope.

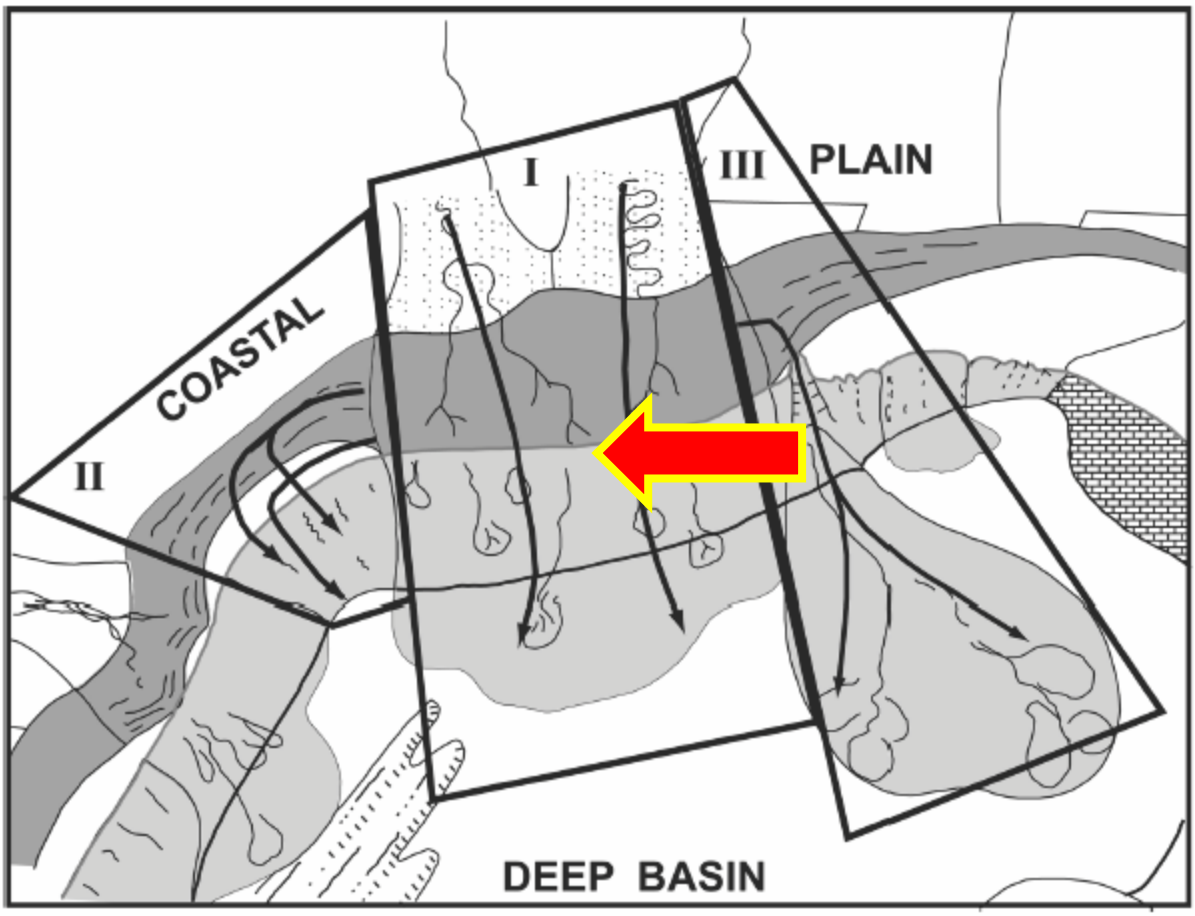


Figure 21, In the Tertiary Gulf of Mexico, there are three important sequences, or styles of shelf margin to basin sedimentation and this is a schematic depiction of the Frio system of coastal Texas:

I. Fluvial to Delta to Delta-fed Apron systems.
II. Coastal Plain to Shore Zone to shelf systems.
III. Delta Flank to Submarine Fan Systems.

Systems II and III have significant along-strike transport of sediment; red arrow indicates approximate position of La Rosa.

Progradation under Low Stand Sea Level Conditions:

Various activities occur in the up-shelf incised valley and deltaic sands environment. The initial sands delivered to the shelf margin bypassed the shelf and built onto the mud-shale paleoslope as slope fans. As outbuilding continued, the slope was bypassed and clastic sediment was deposited into the sub-basins as basin floor fans and turbidites. A ubiquitous feature of this shelf margin outbuilding is the growth fault. Growth faulting initiated during tectonic extension at the shelf margin, and during the accumulation of gravity-transported sediments in a deep water setting. The concurrent slope failure and slump block rotation pushed the plastic, mud dominated surfaces upwards, much like tooth paste, giving rise to upwelling shale, which is often referred to as a shale diapir or shale "toe". The excessive infilling of sediment behind the shale diaper produced an expanded, wedge shaped series of sands and shale on the down-thrown side of the growth fault (figures 22-24). Sediment loading was contemporaneous with progressive movement on the down-thrown side of the growth fault. In response to the extensional stresses, smaller, and important hydrocarbon-trapping antithetic faults developed later, and their displacement was opposite that of the growth fault(s). The sediment wedge was always thicker on the down-thrown side of the fault, and rotation back toward the shelf margin and sediment onlapped the shale diapir. The differential thickening toward the fault and shelf margin accompanies the movement of the fault (or more commonly a system of down-to-the-basin en echelon faults), and can be recognized from seismic and well log analyses

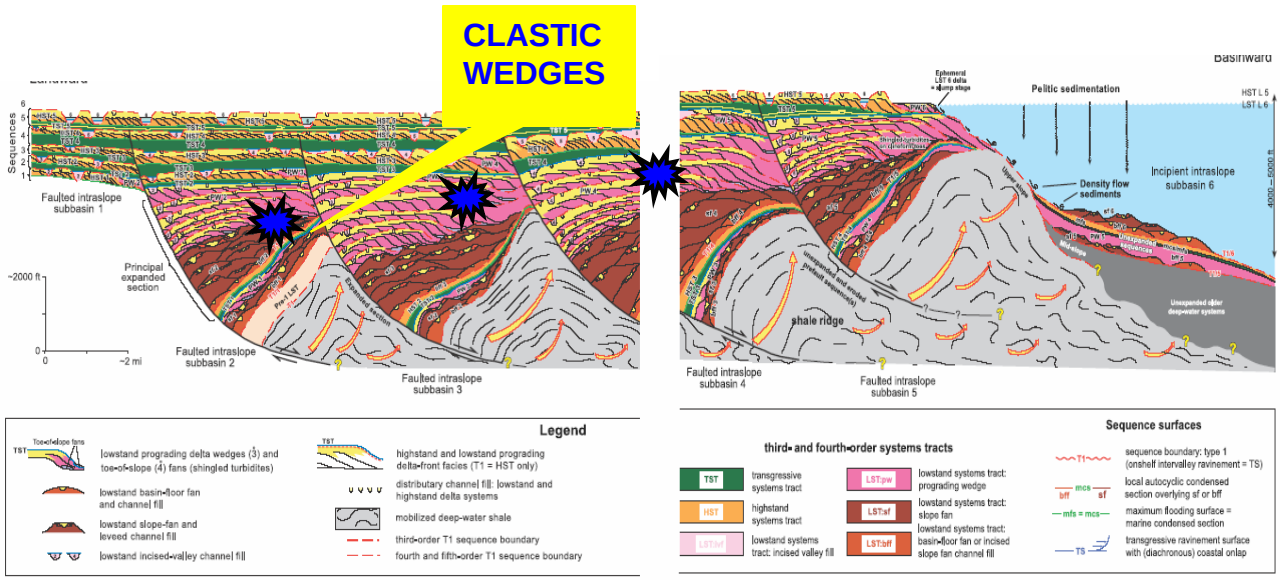


Figure 22, Schematic cross-section illustrating initiation of Frio growth faults by sediment loading on marine muds and rotational faulting causing the characteristic down-thrown thickening and wedging of sediment onto the flanks of diapiric shale. Upward progression of sequences is from marine shale, basin floor fans and turbidites, slope fans and slump blocks, prodelta muds, delta front sands, coastal plain and fluvial facies.

The growth fault did not create the slope. The original slope is a product of the preceding and older formation's instability and weakness that permitted: mass wasting (slump blocks); an up-rising shale ridge; and sediment filling into the expanding gap between the shale diapir and the contemporaneous movement along the fault plane. When the growth fault initiated, it did not align with the slope but created a much steeper plane. Depositional slopes in a clastic shelf environment generally have low dip angles of 1- 2°. Water depth in the down-dip sub-basin might range from 450 to 1000 feet at its deepest part. In between the two sites, the slope angles may have been 4 – 5° or greater. Whatever the dip of the sediment surface, the dip of the normal growth fault plane is significantly higher, generally ranging from 45° to 60°.

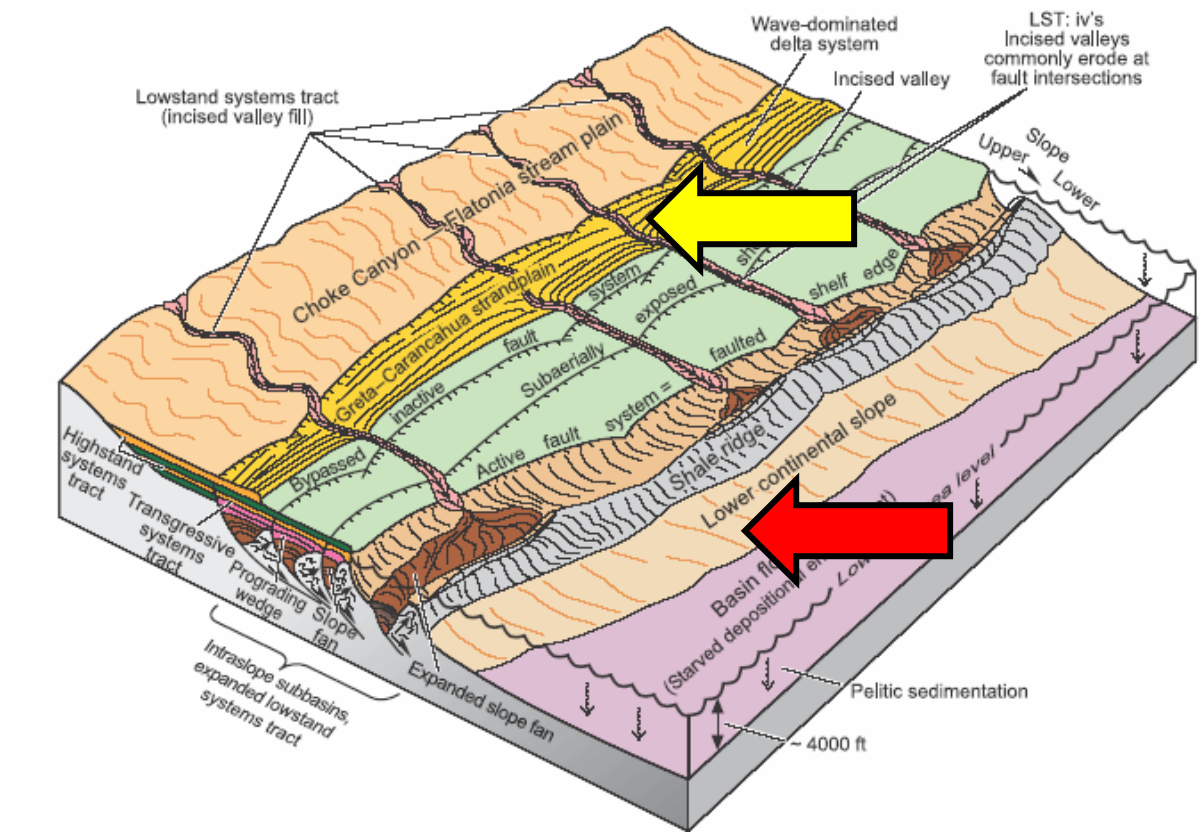


Figure 23, Schematic block-diagram illustrating initiation of growth faults by sediment loading on uncompacted marine muds and & subsequent rotational faulting causing down-thrown thickening and wedging of sediment onto the flanks of diapiric shale. Yellow arrow=La Rosa Upper Frio shelf margin deltaic sediments atop slope and basinal clastics on lapping shale diapir; Red arrow= Distal marine Frio deposited in sub-basins in the Gulf of Mexico

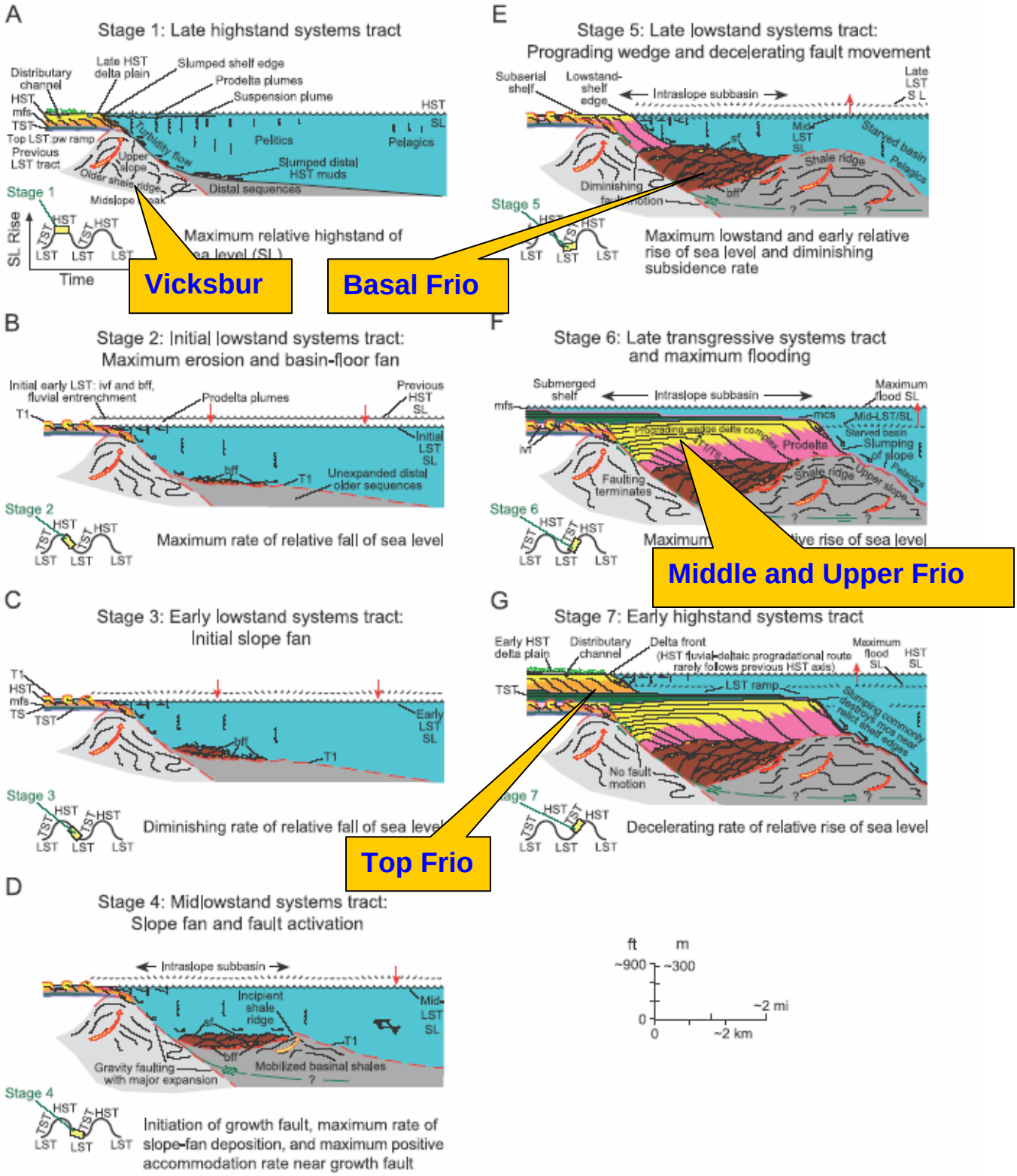


Figure24, Sequence of development marine & deltaic sediments with sea-level changes.

A difficult problem may develop when log correlations and patterns are the sole data utilized. The deep water low-stand systems in an individual sub-basin is a different environment than the on-shelf transgressive and high stand facies that prograded across several buried sub-basins. The environments are diachronous, in that the log patterns may appear to correlate from shelf to basin, but seismic data shows that these environments were not similar in a time-stratigraphic sense, even (though they may appear to be lithologically the same). Strata of the down-dip and down-thrown low-stand slope and basin floor fans systems cannot be correlated with rocks from the incised valleys on the up-dip and up-thrown side of the growth fault. Extension occurred at the top-of-slope shelf position; contraction, and even compression developed in the base-of-slope position. The comparatively thicker section on the downthrown block reflects greater subsidence rates associated with focused structural extension, and is not the due to the development of steeply dipping fault scarps at the shelf margin. The depositional context of these sequences is one of an overall prograding shelf margin.

Strata in growth-faulted settings are characterized by an upward vertical succession of deep marine muds, basin-floor fans, slope fans, prograding delta fronts and deltaic wedges, coastal plane, and shoreline environments, resulting in the classic coarsening-upward regressive character. This vertical succession of systems was typically initiated and deposited basinward of shelf edges during relative low stands of sea-level. The down-thrown thickening is caused by sediment loading in an extensional environment concurrent with an increase in the subsidence rate of the sub-basin. The top-most succession, as seen on seismic data, is commonly referred to as "railroad track" reflections from the relatively thin and highly continuous on-shelf high-stand and transgressive coastal stratigraphic units.

A variety of other types of growth-fault situations and geometries are known to exist, and this variation reflects the broad spectrum of facies that results from the interplay between subsidence rate, tectonic uplift, climate fluctuations, sediment supply, and sea level changes, Sedimentation thickness and facies likely vary along strike and this may be due to the relative position to the focused sediment distribution center and to different subsidence rates.

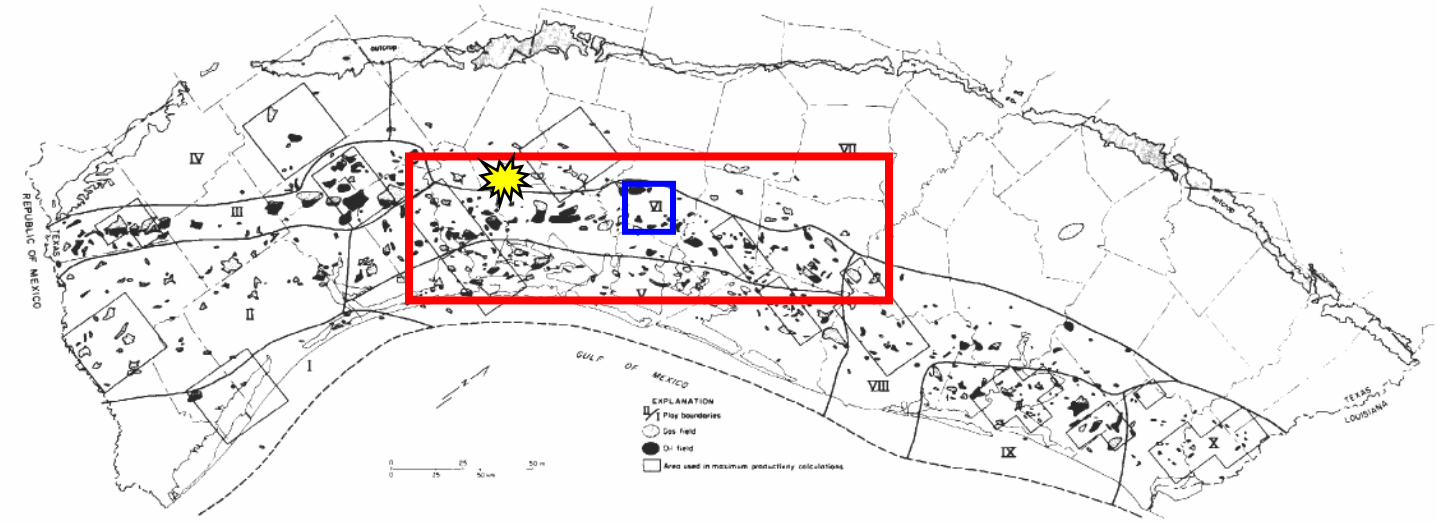


Figure 25, Frio Oil and Gas Production in Texas…La Rosa is in *Play VI*

Play	Cumulative Production					Percent Already Produced		Remaining Proved Reserve				
	Oil (10^6bbl)	Associated gas (10^3mmcf)	Nonassociated gas (10^3mmcf)	Total gas (10^3mmcf and liquid equivalent in 10^6BOE)	Total hydrocarbons (10^6boe)	Oil	Gas	Average oil recovery (%) †	Oil (10^6bbl)	Associated gas (10^3mmcf)	Nonassociated gas (10^3mmcf)	Average BOE gas / bbl oil
I	29	281	185	466 / 80	107	~60	~60	34	3.6	9.6	303	2.7
II	50	1	6,530	6,531 / 1,090	1,140	—	81	34	0	0	1,600	22
III	917	7,690	7,110	14,800 / 2,470	3,390	96	91	34	28	322	1,500	2.7
IV	52	2	77	79 / 15	65	100	95	34	1	0.04	6	0.2
V	519	4,200	7,700	11,900 / 1,980	2,500	98	83	44	11	89	2,400	3.8
VI	2,500	4,750	5,850	10,600 / 1,765	4,230	85	90	44	440	836	1,200	0.7
VII	41	45	886	931 / 155	191	82	83	46	8	8.2	199	4.8
VIII	1,620	1,110	2,440	3,550 / 590	2,210	77	85	48	490	336	630	0.4
IX	857	2,120	4,150	6,270 / 1,045	1,900	89	88	48	110	272	870	1.2
X	236	465	1,530	1,995 / 330	567	96	83	48	9	17.7	420	1.4
TOTAL	6,821	20,664	36,458	57,122 / 9,520	16,300				1,100	1,890	9,130	1.4

* Calculated energy equivalent in bbls of oil (6 mcf = 1 BOE)

† Figures apply to entire production within the RR Commission District in which the play lies

‡ Exclusive of a giant field lying within the play

Figure 26, Production summaries for Frio Plays. Play VI is the area within La Rosa is located.

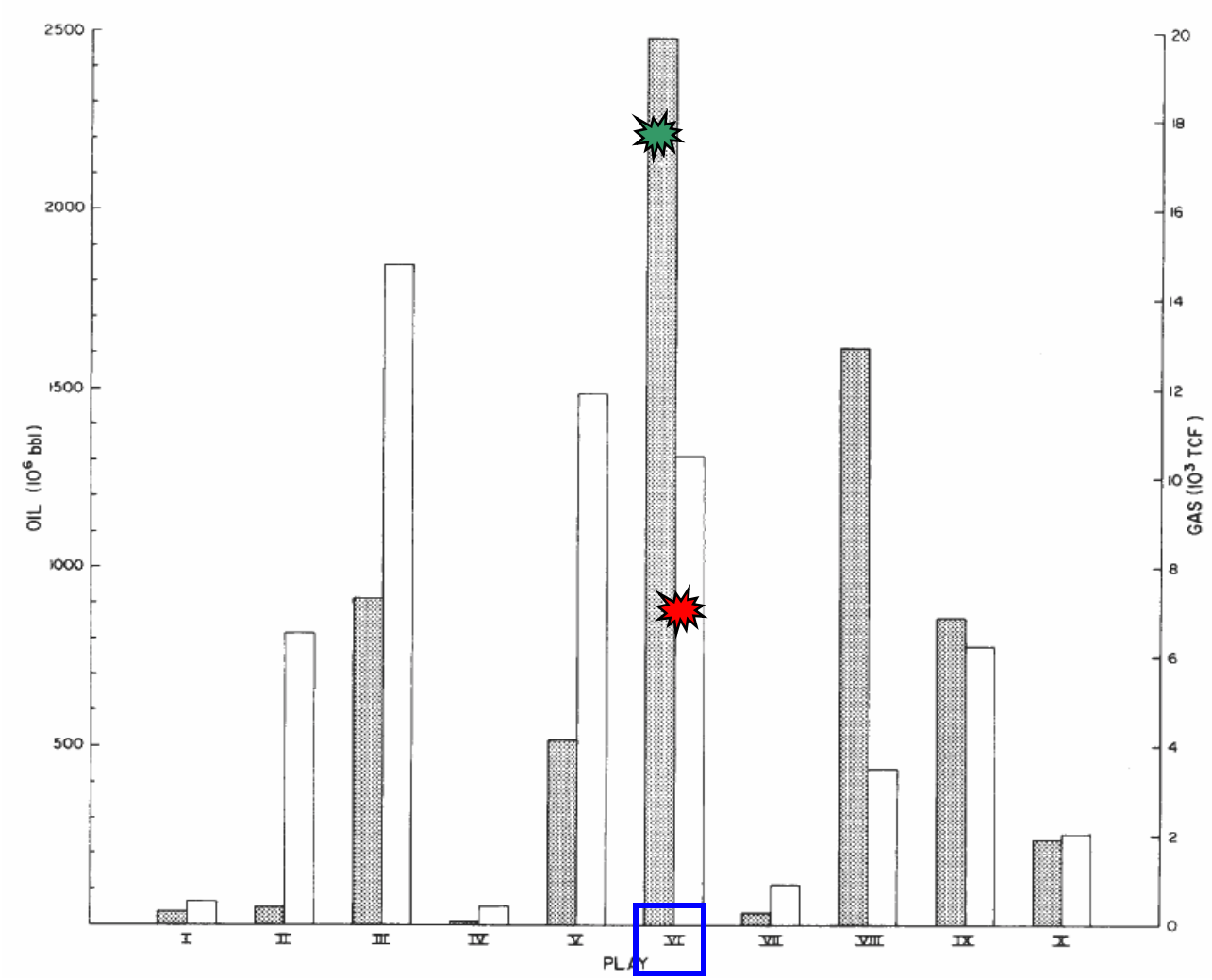


Figure 27, Frio Oil and Gas Production by Play…La Rosa is in *Play VI*

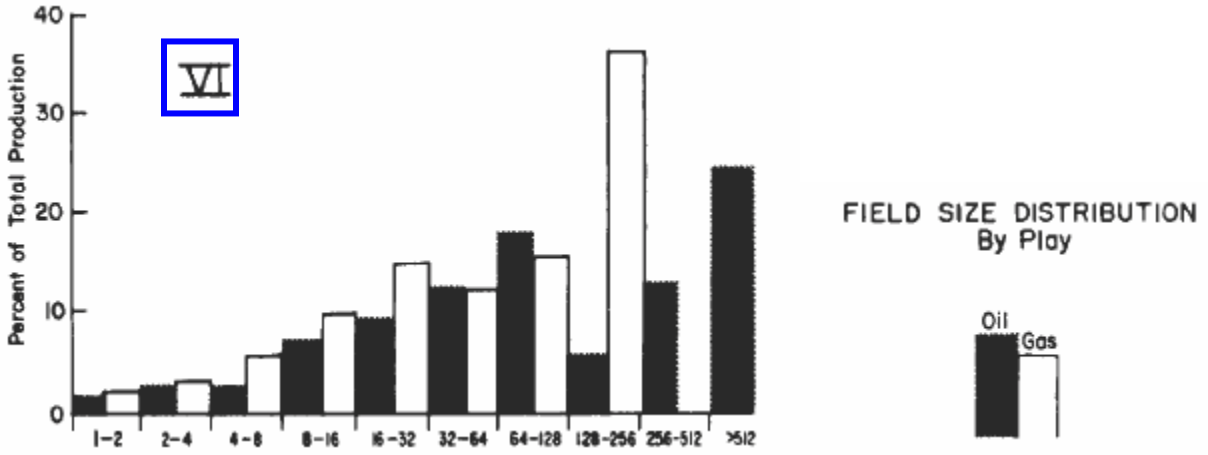


Figure 28, Field size distribution. Play VI

Vicksburg Depositional Setting

The previous examples depicting the growth fault settings of the Gulf Coast were from the Upper Oligocene Frio formation. However, the Lower Oligocene Vicksburg was deposited in very similar fashion, but its depocenters are located predominantly toward the Rio Grande and Houston embayments. Approximately 400 fields produce from the Vicksburg Formation within the state of Texas. These fields have produced cumulative totals of over 300 million barrels of oil, 40 million barrels of condensate, and 6 trillion cubic feet (TCF) of gas.

The Vicksburg growth fault systems consist of interconnected, arcuate faults that generally parallel the present coastline; these fault systems track the shelf margin position at the time of deposition. The regional basin ward dip of the Vicksburg section is interrupted by several major growth fault systems, one of which, the Vicksburg flexure, is a major control on the thickening of the Vicksburg stratigraphic section. Most of the Vicksburg fields are associated with faults and commonly are structural-stratigraphic combination traps. The location of the fields is determined primarily by the distribution of the reservoir sandstones and secondarily by the presence of local structure...

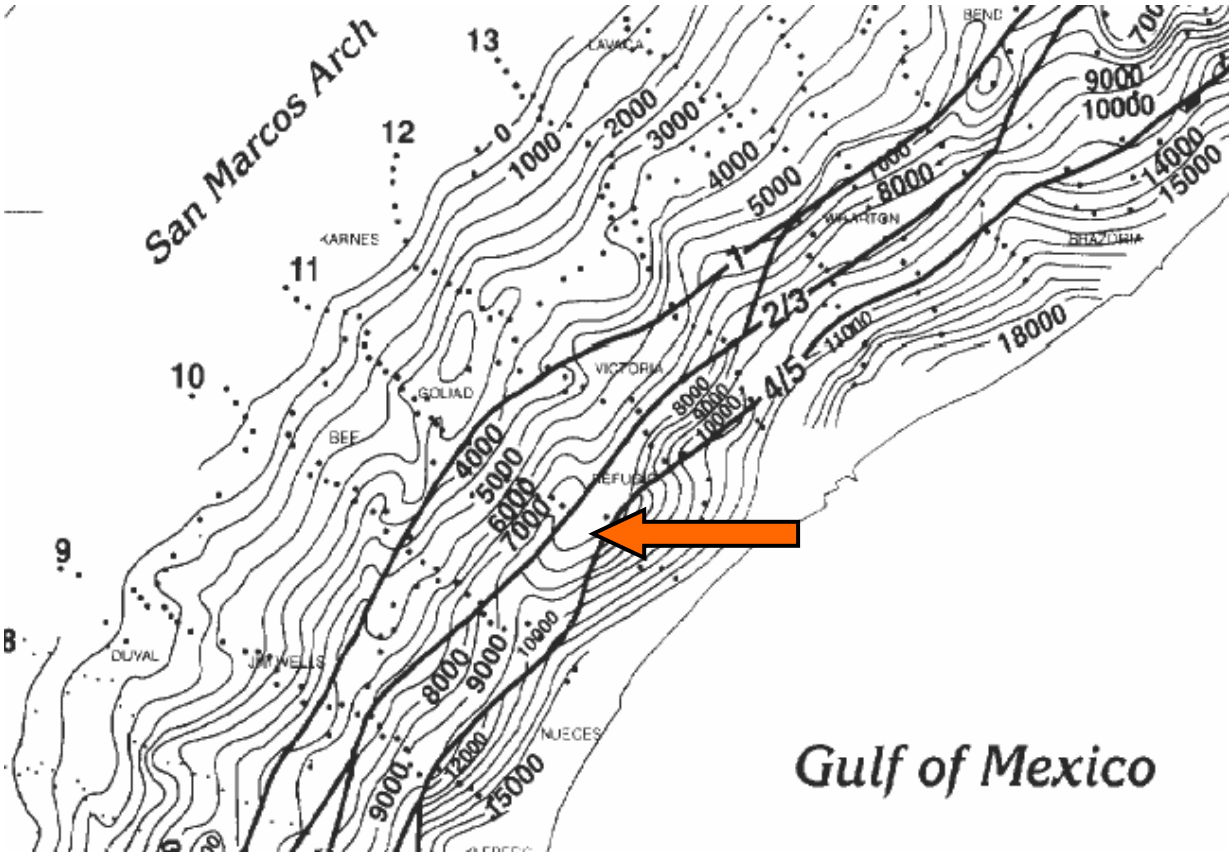


Figure 29, Structure Map top of Vicksburg (base of Frio)

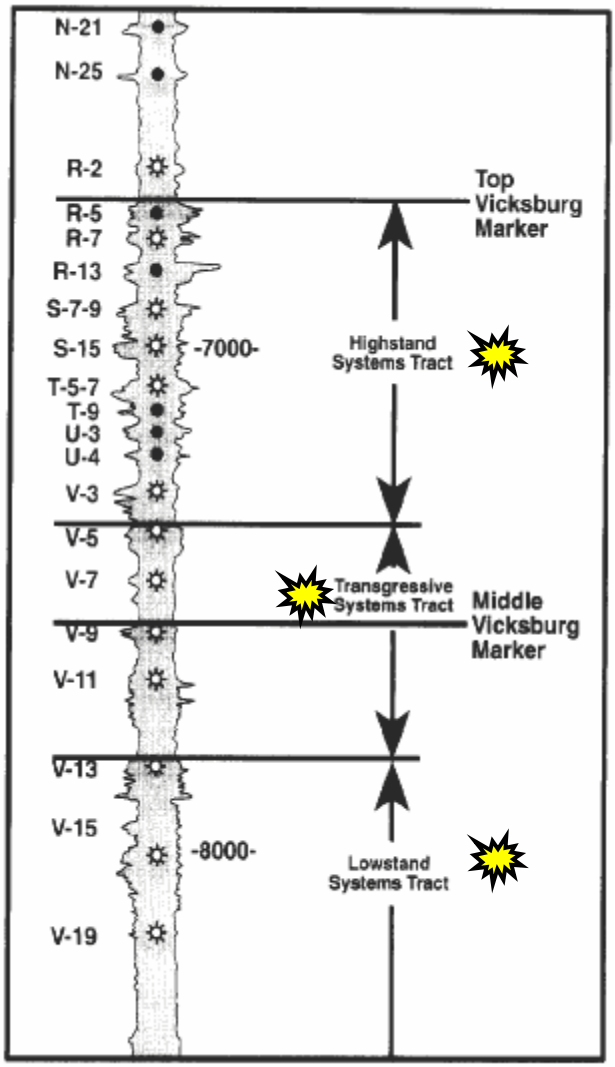


Figure 30, Typical upward coarsening, increasingly shallow water profile of Vicksburg well log.

The Vicksburg Formation is productive across the San Marcos Arch, although not as prolifically as in the Rio Grande Embayment straddling the U.S.-Mexican Border. In Goliad County, adjacent to Refugio County, Vicksburg production has been recorded in 17 oil and/or gas fields. The Vicksburg units in this area are dominated by a strike-oriented paralic sand complex composed of wave-dominated deltas and delta flanks, with their associated shore-zone and barrier systems. The reservoir sands in this area are located in the transgressive and high-stand complex of barrier bars and small deltas similar to the overlying Frio environments. Some of the fields within this Vicksburg petroleum play are located in high-stand outer-shelf, prodelta-to-upper-slope mass-flow deposits.

Although large Vicksburg fields are rare in the San Marcos arch area, there are numerous smaller producers. More exploration seaward of distributary channel mouths may encounter new reservoirs in the delta-front/prodelta/ponded-fill of outer-shelf topographic depressions, and this is the anticipated environment of

deposition for the virtually untested La Rosa area.

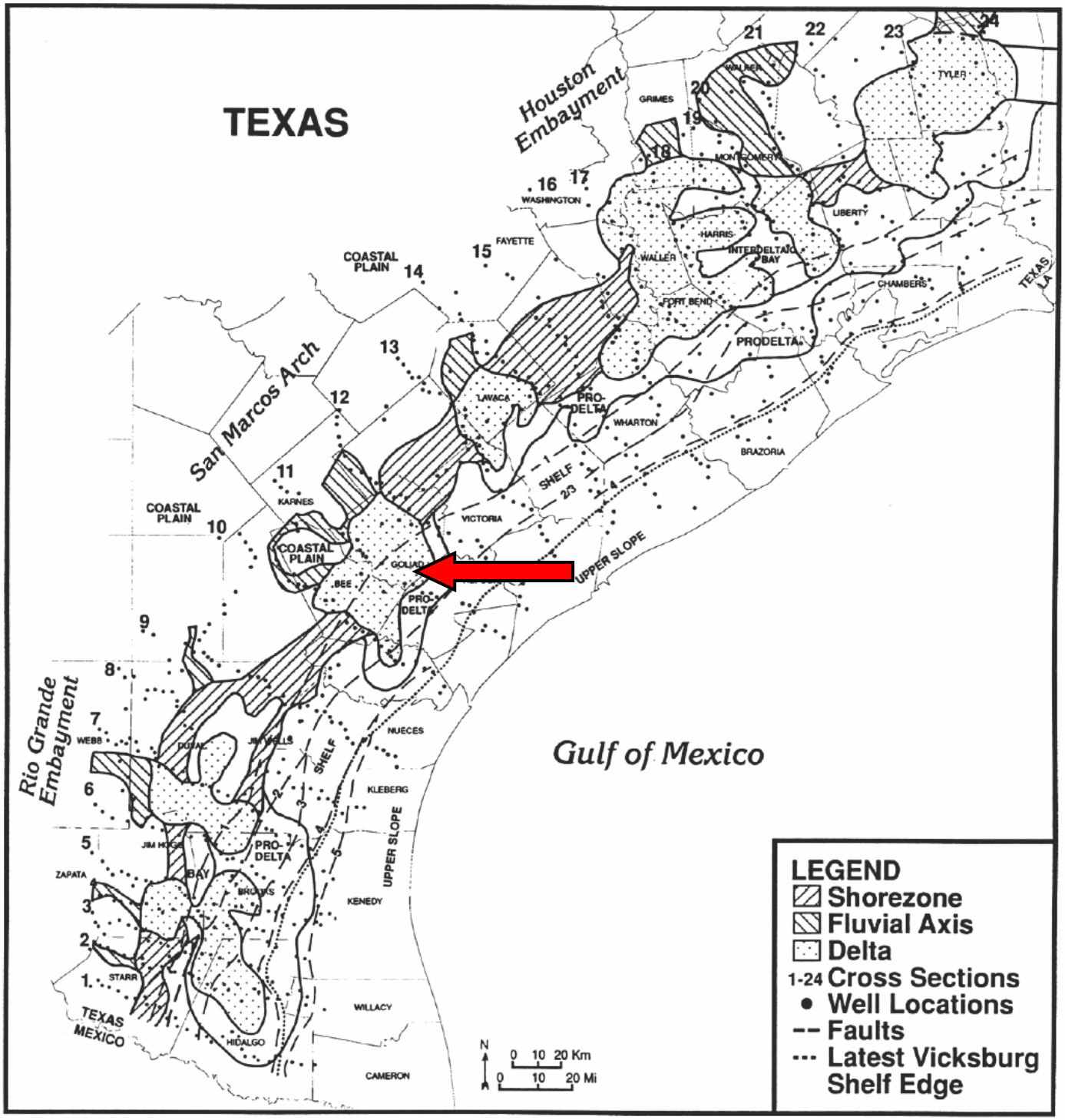


Figure 31, Lower Vicksburg Paleogeography and principal Vicksburg Fault traces

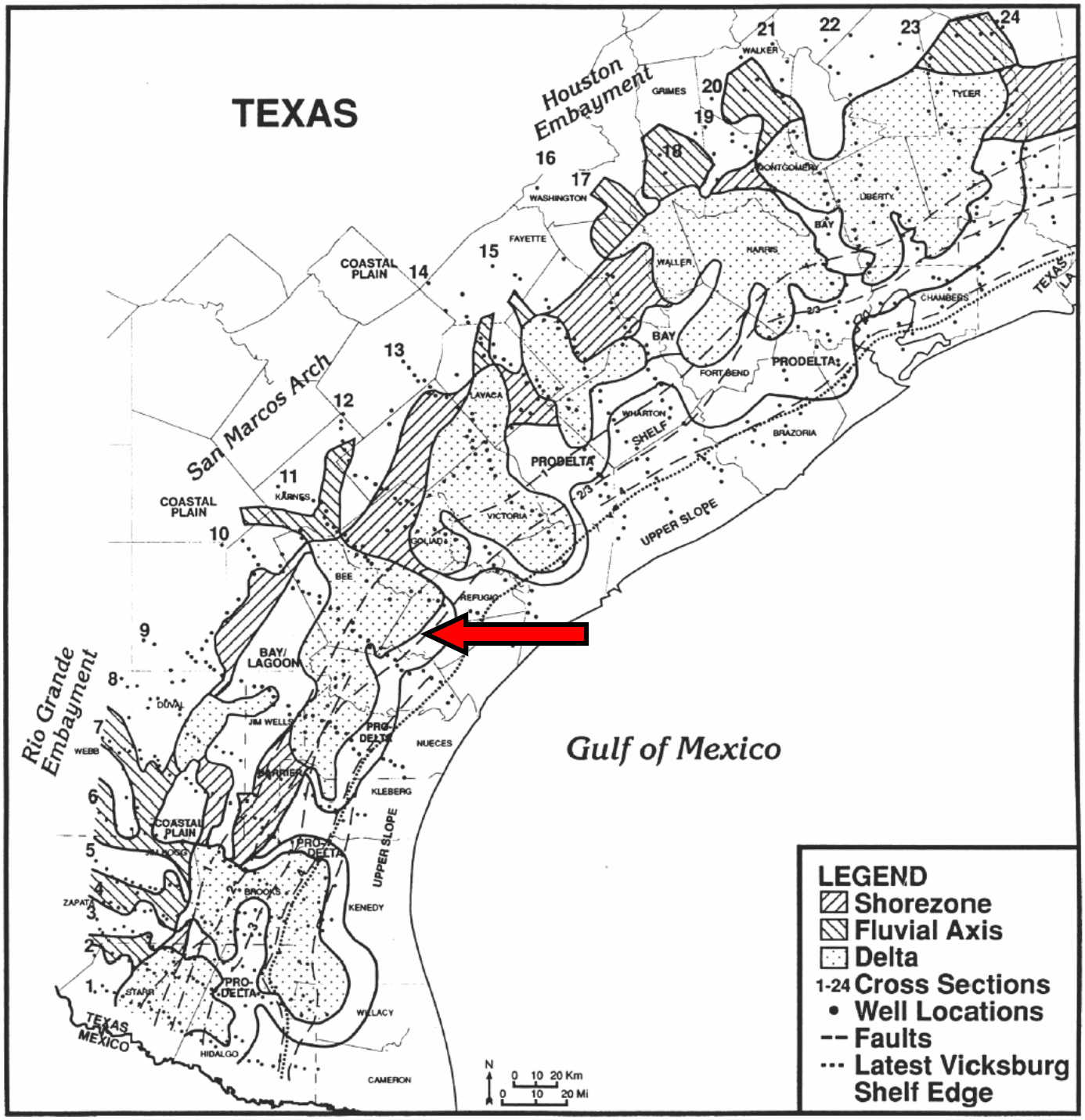


Figure 32, *Upper Vicksburg* Paleogeography and principal Vicksburg Fault traces

The Vicksburg growth faults in the Rio Grande embayment sole out in the upper section of the Jackson Group shales. In the San Marcos arch and the Houston embayment, the faults are listric deeper within the Cenozoic section (Jackson and Yegua). All of these areas contained the structural features commonly associated with growth faults: rollover anticlines, antithetic faults, and diapirs.

The San Marcos arch region contained a Vicksburg wave-dominated barrier/strand-plain complex with minor deltas. Sequence stratigraphic analyses of the Vicksburg Formation reveal a coast-wide seaward shift of paralic facies at the Jackson/Vicksburg boundary; the regional extent of the drop in relative sea level, occurring across several depocenters, indicates that sea-level change was the cause of the drop. A middle Vicksburg transgression and an upper Vicksburg progradation are also seen. The Vicksburg/Frio boundary is identified regionally by a resistivity marker that corresponds to a change in the depositional modes from progradational in the upper Vicksburg section to aggradational in the Lower Frio. Generally, the Vicksburg section corresponds to a depositional sequence model with a lower marine boundary (Jackson/Vicksburg), a lower Vicksburg low-stand systems tract, a middle Vicksburg transgressive systems tract, and an upper Vicksburg high-stand systems tract. The upper sequence boundary (Vicksburg/Frio contact) is an unconformity.

The majority of fields with cumulative Vicksburg production of more than 1 billion ft3 of gas and/or 1 million bbl of oil produce from deltaic sandstones. Barrier/strand-plain and fluvial reservoirs account for only a few fields. Outer shelf depression-fill deposits of delta-front or prodelta origin account for a number of reservoirs. Although distributary mouth and shelf delta sandstones deposited under transgressive and high stand conditions are the reservoirs typical of play in the San Marcos arch area, the deeply buried lowermost Vicksburg section has potential reservoirs of mass-flow (slump blocks and slope fans), or turbidite deposits of the basin-floor fans. Seismic lines shown in the segment of this report dealing with the La Rosa field indicate distal, basinal reflectors onlapping and pinching out against the shale diapir, as illustrated in the Frio examples at the beginning of the Appendix.

APPENDIX B: AFTER TAX PROJECTIONS

After Tax Net Income

It is estimated that the company will face a reduction of net income at a rate of 20% annually. The estimate is derived from the application of 35% estimated tax rate. The tax is reduced in that operators may immediately utilize approximately 75% of drill costs (Intangible Drilling Costs, or IDC's) to shield income. The remaining drill costs (Tangible Drilling Costs of TDC's) are also depreciated based on the amount of production compared to the estimated remaining oil and gas reserves on a field by field basis. The actual tax rate will depend on production rates, existing corporate tax benefits, rate of drilling and other capital expenditures, and the rate of tax applied by the applicable jurisdictions.

Forward-Looking Statements

Certain statements in this report including statements of the expected results, objectives, and expected performance of the reserves, are forward-looking statements that are dependent upon certain events, risks and uncertainties that may be outside of an operator's control, and which could cause actual results to differ materially from those anticipated. Some of these include, but are not limited to, the market prices of oil and gas, economic and competitive conditions, inflation rates, legislative and regulatory changes, financial market conditions, political and economic uncertainties of foreign governments, future business decisions, and other uncertainties, all of which are difficult to predict.

There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserves and production estimates. The drilling of exploratory wells can involve significant risks, including those related to timing, success rates and cost overruns. Lease and rig availability, complex geology, well mechanical failure and other factors can affect these risks.

LAROSA FIELD

Flat Price Case

O N E L I N E S U M M A R Y

LEASE NAME	BFIT NET INCOME (M$)	AFT NET INCOME ($M)	DISC 10% BFIT NET INC (M$)	DISC 10% AFT NET INC ($M)
LA ROSA C-14 PDP	$1,170.9	$936.7	$1,010.7	$808.6
LA ROSA GAS UNIT 47	$90.4	$72.3	$82.6	$66.1
LA ROSA GAS UNIT 52	$38.2	$30.6	$35.2	$28.2
LA ROSA UNIT 46	$61.5	$49.2	$55.9	$44.7
LAROSA GAS UNIT 16	$1,700.7	$1,360.6	$656.6	$525.3
LAROSA OIL	$621.7	$497.4	$472.7	$378.2
ROOKE C-10	$660.0	$528.0	$578.3	$462.6
ROOKE GAS UNIT 1-A	$229.8	$183.8	$203.1	$162.5
PROVED DEVELOPED PRODUCING	**$4,573.3**	**$3,658.6**	**$3,095.0**	**$2,476.0**
LA ROSA C-14 PDNP	$3,826.1	$3,060.9	$1,803.7	$1,443.0
PROVED DEVELOPED NON-PRODUCING	**$3,826.1**	**$3,060.9**	**$1,803.7**	**$1,443.0**
LA ROSA C-15 PUD	$680.8	$544.6	$622.2	$497.8
LA ROSA C-16 PUD	$1,473.7	$1,179.0	$1,291.4	$1,033.1
LA ROSA C-17 PUD	$4,921.3	$3,937.0	$3,911.9	$3,129.5
LA ROSA C-18 PUD	$4,108.8	$3,287.0	$3,020.1	$2,416.1
LA ROSA C-18 PUD BP1	$3,088.1	$2,470.5	$940.0	$752.0
MICHNA NO 13 PUD	$536.2	$429.0	$447.0	$357.6

PROVED UNDEVELOPED	**$14,808.8**	**$11,847.0**	**$10,232.6**	**$8,186.1**
		$0.0		
3390 NO. BRIGHT SPOT	$692.1	$553.7	$551.2	$441.0
3390 SO. BRIGHT SPOT	$1,532.0	$1,225.6	$1,172.7	$938.2
3450' MICHNA #12	$901.7	$721.4	$639.7	$511.8
3800 NO. BRIGHT SPOT	$1,057.6	$846.1	$842.8	$674.2
3800 SO. BRIGHT SPOT	$2,688.0	$2,150.4	$1,890.4	$1,512.3
5200' YARROW #1	$1,506.7	$1,205.4	$1,028.6	$822.9
6200' NORTH A1	$3,625.6	$2,900.5	$2,454.2	$1,963.4
6200' NORTH C-6	$3,625.6	$2,900.5	$2,473.8	$1,979.0
6200' NORTH LOC4	$6,539.7	$5,231.8	$4,378.8	$3,503.0
6500' LOC4	$4,981.8	$3,985.4	$3,391.6	$2,713.3
6500' LOC5	$6,203.9	$4,963.1	$4,058.4	$3,246.7
BELOW DRISCOLL A #1	$1,561.6	$1,249.3	$970.9	$776.7
BELOW DRISCOLL A #2	$4,248.3	$3,398.6	$2,469.6	$1,975.7
BELOW DRISCOLL A #3	$894.7	$715.8	$606.4	$485.1
DRISCOLL 8,000	$744.3	$595.4	$515.1	$412.1
GRETA 1	$1,708.5	$1,366.8	$1,145.6	$916.5
GRETA 2	$1,708.5	$1,366.8	$1,145.6	$916.5
GRETA 3	$1,708.5	$1,366.8	$1,145.6	$916.5
ROOKE HIGH - 7500'	$488.3	$390.6	$382.5	$306.0
ROOKE HIGH 6,900'	$1,627.2	$1,301.8	$1,024.0	$819.2
ROOKE HIGH 7,300'#1	$4,885.0	$3,908.0	$2,717.6	$2,174.1
ROOKE HIGH 7,300'#2	$4,885.0	$3,908.0	$2,717.6	$2,174.1
ROOKE HIGH 7,300'#3	$4,885.0	$3,908.0	$2,717.6	$2,174.1
SINTON, WEST 1	$1,430.1	$1,144.1	$990.8	$792.6
SINTON, WEST 2	$816.9	$653.5	$612.9	$490.3
SINTON, WEST 3	$651.4	$521.1	$489.2	$391.4
VICKSBURG #1	$9,845.5	$7,876.4	$5,515.4	$4,412.3
VICKSBURG #2	$9,845.5	$7,876.4	$5,515.4	$4,412.3
VICKSBURG #3	$9,845.5	$7,876.4	$5,471.8	$4,377.4
VICKSBURG #4	$9,845.5	$7,876.4	$5,428.5	$4,342.8
VICKSBURG #5	$9,845.5	$7,876.4	$5,428.5	$4,342.8
WYRICK 1	$4,870.7	$3,896.6	$3,187.1	$2,549.7
WYRICK 2	$4,870.7	$3,896.6	$3,187.1	$2,549.7
WYRICK 3	$4,870.7	$3,896.6	$3,187.1	$2,549.7
PROBABLE	**$129,437.5**	**$103,550.0**	**$79,453.7**	**$63,563.0**
VICKSBURG #10	$14,149.1	$11,319.3	$6,593.0	$5,274.4
VICKSBURG #6	$14,149.1	$11,319.3	$6,805.8	$5,444.6
VICKSBURG #7	$14,149.1	$11,319.3	$6,752.0	$5,401.6
VICKSBURG #8	$14,149.1	$11,319.3	$6,698.6	$5,358.9
VICKSBURG #9	$14,149.1	$11,319.3	$6,645.6	$5,316.5
POSSIBLE	**$70,745.5**	**$56,596.4**	**$33,494.9**	**$26,795.9**
GRAND TOTAL	**$223,391.2**	**$178,713.0**	**$128,079.8**	**$102,463.8**

LAROSA FIELD

Forecast Price Case

O N E L I N E S U M M A R Y

LEASE NAME	BFIT NET INCOME (M$)	AFT NET INCOME ($M)	DISC 10% NET INC (M$)	DISC 10% AFT NET INC ($M)
LA ROSA C-14 PDP	$1,106.6	$885.3	$968.2	$774.6
LA ROSA GAS UNIT 47	$79.4	$63.5	$72.9	$58.3
LA ROSA GAS UNIT 52	$29.6	$23.7	$27.7	$22.2
LA ROSA UNIT 46	$48.4	$38.7	$44.7	$35.8
LAROSA GAS UNIT 16	$864.0	$691.2	$436.6	$349.3
LAROSA OIL	$503.3	$402.6	$405.7	$324.6
ROOKE C-10	$579.5	$463.6	$515.4	$412.3
ROOKE GAS UNIT 1-A	$194.3	$155.4	$174.7	$139.8
PROVED DEVELOPED PRODUCING	**$3,405.1**	**$2,724.1**	**$2,645.9**	**$2,116.7**
LA ROSA C-14 PDNP	$2,877.4	$2,301.9	$1,382.9	$1,106.3
PROVED DEVELOPED NON-PRODUCING	**$2,877.4**	**$2,301.9**	**$1,382.9**	**$1,106.3**
LA ROSA C-15 PUD	$632.8	$506.2	$580.6	$464.5
LA ROSA C-16 PUD	$1,338.1	$1,070.5	$1,182.2	$945.8
LA ROSA C-17 PUD	$4,515.0	$3,612.0	$3,659.3	$2,927.4
LA ROSA C-18 PUD	$3,648.1	$2,918.5	$2,730.2	$2,184.2
LA ROSA C-18 PUD BP1	$2,282.6	$1,826.1	$699.1	$559.3
MICHNA NO 13 PUD	$468.0	$374.4	$390.4	$312.3
PROVED UNDEVELOPED	**$12,884.5**	**$10,307.6**	**$9,241.9**	**$7,393.5**
		$0.0		
3390 NO. BRIGHT SPOT	$579.4	$463.5	$463.2	$370.6
3390 SO. BRIGHT SPOT	$1,261.8	$1,009.4	$977.6	$782.1
3450' MICHNA #12	$669.7	$535.8	$475.7	$380.6
3800 NO. BRIGHT SPOT	$897.0	$717.6	$718.6	$574.9
3800 SO. BRIGHT SPOT	$2,122.7	$1,698.2	$1,524.5	$1,219.6
5200' YARROW #1	$1,107.8	$886.2	$756.0	$604.8
6200' NORTH A1	$2,777.9	$2,222.3	$1,899.0	$1,519.2
6200' NORTH C-6	$2,798.2	$2,238.6	$1,930.1	$1,544.1
6200' NORTH LOC4	$5,098.7	$4,079.0	$3,463.5	$2,770.8
6500' LOC4	$3,878.0	$3,102.4	$2,672.0	$2,137.6
6500' LOC5	$4,782.6	$3,826.1	$3,177.6	$2,542.1
BELOW DRISCOLL A #1	$1,194.9	$955.9	$737.9	$590.3

BELOW DRISCOLL A #2	$3,329.6	$2,663.7	$1,954.3	$1,563.4
BELOW DRISCOLL A #3	$592.0	$473.6	$389.3	$311.4
DRISCOLL 8,000	$555.3	$444.2	$375.1	$300.1
GRETA 1	$1,403.5	$1,122.8	$956.0	$764.8
GRETA 2	$1,403.5	$1,122.8	$956.0	$764.8
GRETA 3	$1,403.5	$1,122.8	$956.0	$764.8
ROOKE HIGH - 7500'	$402.4	$321.9	$315.8	$252.6
ROOKE HIGH 6,900'	$1,278.1	$1,022.5	$811.6	$649.3
ROOKE HIGH 7,300'#1	$3,851.4	$3,081.1	$2,190.2	$1,752.2
ROOKE HIGH 7,300'#2	$3,851.4	$3,081.1	$2,190.2	$1,752.2
ROOKE HIGH 7,300'#3	$3,851.4	$3,081.1	$2,190.2	$1,752.2
SINTON, WEST 1	$1,081.6	$865.3	$758.9	$607.1
SINTON, WEST 2	$645.1	$516.1	$486.1	$388.9
SINTON, WEST 3	$508.7	$407.0	$381.6	$305.3
VICKSBURG #1	$7,332.2	$5,865.8	$4,140.1	$3,312.1
VICKSBURG #2	$7,332.2	$5,865.8	$4,140.1	$3,312.1
VICKSBURG #3	$7,305.9	$5,844.7	$4,088.7	$3,271.0
VICKSBURG #4	$7,279.0	$5,823.2	$4,037.4	$3,229.9
VICKSBURG #5	$7,279.0	$5,823.2	$4,037.4	$3,229.9
WYRICK 1	$4,081.5	$3,265.2	$2,733.2	$2,186.6
WYRICK 2	$4,081.5	$3,265.2	$2,733.2	$2,186.6
WYRICK 3	$4,081.5	$3,265.2	$2,733.2	$2,186.6
PROBABLE	**$100,098.8**	**$80,079.0**	**$62,350.5**	**$49,880.4**
VICKSBURG #10	$10,232.4	$8,185.9	$4,795.1	$3,836.1
VICKSBURG #6	$10,308.0	$8,246.4	$5,001.1	$4,000.9
VICKSBURG #7	$10,289.5	$8,231.6	$4,949.2	$3,959.4
VICKSBURG #8	$10,270.7	$8,216.6	$4,897.6	$3,918.1
VICKSBURG #9	$10,251.7	$8,201.4	$4,846.2	$3,877.0
POSSIBLE	**$51,352.3**	**$41,081.8**	**$24,489.2**	**$19,591.4**
GRAND TOTAL	**$170,618.1**	**$136,494.5**	**$100,110.5**	**$80,088.4**