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APPRAISAL REPORT
as of
DECEMBER 31, 2001
on
BLOCK 405B
in
ALGERIA
for
FIRST CALGARY PETROLEUMS LTD.

CANADIAN POLICY 2B CASE

TABLE of CONTENTS

Page

FOREWORD 1
Scope of Investigation 1
Authority 2
Source of Information 2
GEOLOGY 4
Structure 5
Volume in Place 6
CLASSIFICATION of RESERVES 9
ESTIMATION of RESERVES 12
VALUATION of RESERVES 16
SUMMARY and CONCLUSIONS 19
Professional Qualifications 20
TABLES
Table 1 – Gross and Net Reserves
Table 2 – Future Net Revenue Summary
Table 3 – Reservoir Parameters and Original Gas in Place
Table 4 – Production Forecast, Proved Reserves
Table 5 – Production Forecast, Proved-plus-Probable Reserves
Table 6 – Production Forecast, Proved-plus-Risk-Adjusted-Probable Reserves
Table 7 – Future Net Revenue, Proved Reserves
Table 8 – Future Net Revenue, Proved-plus-Probable Reserves
Table 9 – Future Net Revenue, Proved-plus-Risk-Adjusted-Probable Reserves
FIGURES
Figure 1 – Location Map
Figure 2 – Stratigraphic Column
Figure 3 – Structure Map, F1 Reservoir

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FOREWORD

Scope of Investigation

This report presents an appraisal, as of December 31, 2001, of the extent and value of the proved and probable natural gas, condensate, and liquefied petroleum gas (LPG) reserves, and the extent only of the possible reserves, of the Menzel Ledjmet Block 405B (Block 405B) in the Berkine basin of Algeria. The appraisal was prepared according to Canadian Provincial Securities Administrators National Policy 2B requirements at the request of First Calgary Petroleums Ltd. (First Calgary), which owns 75 percent of the contractor's interest under the terms of a production sharing contract (PSC) in the block.

Reserves estimated in this report are expressed as gross and net reserves. Gross reserves are defined as the total estimated petroleum to be produced after December 31, 2001, from Block 405B. Net reserves are defined as that portion of the gross reserves attributable to First Calgary's interest in the PSC after deducting all interests owned by others. Table 1 summarizes the reserves estimated in this report.

This report presents values that were estimated for proved and proved-plus-probable reserves using current prices and costs provided by First Calgary. Prices and costs were expressed in United States

dollars (U.S.$), and all monetary values in this report are expressed in U.S.$. A detailed explanation of future price and cost assumptions is included in the Valuation of Reserves section of this report.

Values for proved and proved-plus-probable reserves in this report are expressed in terms of estimated future gross revenue, future net revenue, and present worth. Future gross revenue is defined as that revenue to be realized from the sale of the net reserves. Future net revenue is defined as the gross revenue less direct operating expenses and capital expenditures. Direct operating expenses include operating costs, petroleum processing costs, compression costs, and estimated expenses of direct supervision. Capital costs include such items as surface production facilities, pipelines, and wells. Future Canadian income taxes have not been accounted for in this evaluation. Present worth is defined as future net revenue discounted at a specified arbitrary discount rate compounded monthly over the expected period of realization. In our opinion, present worth should not be construed to represent fair market value of the properties evaluated herein. In this report, present worth values are estimated using discount rates of 10, 15, and 20 percent. Table 2 summarizes the future net revenue estimated in this report.

Estimates of oil and gas reserves and future net revenue should be regarded only as estimates that may change as production history and additional information become available. Not only are such reserves and revenue estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Authority

This report was authorized by Mr. Mike Brusset, Manager of Engineering, First Calgary.

Source of Information

Information used in the preparation of this report was obtained from First Calgary. In the preparation of this report we have relied, without independent verification, upon information furnished by First Calgary with respect to property interests, production from such properties, costs of operation and development, current prices for production, agreements relating to future operations and sale of

production, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report, since all pertinent data was available for review and there are no special circumstances regarding the location of the block evaluated that would require a field examination.

GEOLOGY

The area evaluated in this report is located in the Berkine (formerly Ghadames) basin of Algeria (Figure 1). Block 405B, also called the Menzel Ledjmet area, is approximately 1,108 square kilometers. First Calgary has acquired the rights to Block 405B for the purpose of exploring and developing the gas and liquids reserves producible from the block. The data provided were limited to well data from two wells drilled prior to First Calgary's acquisition of the block, some minimal test information, and two-dimensional (2–D) seismic data.

The first well on the block, MZL–1, was drilled in 1987 by Hispanoil. This well reached a total depth of 4,500 meters and penetrated the Lower Devonian Gedinnien Formation. Log calculations of net pay indicate there is pay scattered throughout the well ranging from 4,100 meters true vertical depth subsea (TVDSS) up to 3,208 meters TVDSS. Three zones in this well were tested.

The Devonian section labeled F6–1 (Figure 2) was perforated across a 30-meter interval, but the well was unable to unload a 3,000-meter column of water. Log-calculated pay in the deeper F6–2 interval was not tested. The Triassic Argile Greseux Inferieur (TAGI) interval in the MZL–1 well was tested using a 1,000-meter water column. This test recovered 8,400 liters of water, but the salinity of the water recovered during this test was much lower than TAGI Formation water. The Triassic Argile Greseux Superieur (TAGS) sand at about 3,100 meters TVDSS was also tested. This zone did not flow and was interpreted to be tight.

Louisiana Land & Exploration (LL&E) drilled the MLE–1 well in 1995 to a depth of 4,400 meters TVDSS. This well also penetrated the Lower Devonian Gedinnian Formation. The MLE–1 well is approximately 16.1 kilometers to the northeast of MZL–1. Existing seismic data indicate the MZL–1 and MLE–1 wells are located on separate structural closures.

The well encountered log-calculated pay from 4,084 meters TVDSS in the Devonian up to 2,938 meters TVDSS in the TAGI. Of the three zones tested, the deepest was from the Devonian at about 4,000 meters TVDSS. This interval tested about 160 thousand cubic meters per day (Mm^3/d), or 5.66 million cubic feet per day (MMcf/d). The next zone to be tested was the F1, which is a combination of Carboniferous Tournasian sand and the underlying Devonian

Strunian sand. This interval tested 784 Mm^3/d (27.69 MMcf/d) with 190 cubic meters (1,197 barrels) of condensate per day.

The shallowest interval tested was the TAGI. While a 70-meter interval was perforated, there appears to be no more than about 4 meters of net pay at the top of this zone. The rest of the reservoir appears to be wet based on log analysis, and three tests of this zone support this interpretation. The final test produced 114 Mm^3/d (4.04 MMcf/d) of gas, no condensate, and 51 cubic meters (322 barrels) of water. The two earlier tests produced condensate along with water and gas.

Structure

Eight 2–D seismic lines shot between 1994 and 1995 were available for this evaluation. These data provided adequate but sparse control to map the structure between the MLE–1 and MZL–1 wells. The data are of fair to good quality for mapping above the Hercynian unconformity, including the TAGI sand, but fair to poor for mapping the deeper reservoirs. Synthetic seismograms were provided to tie the wells to the seismic data. These ties were fair to poor, but adequate for structural mapping. The Hercynian unconformity is difficult to interpret with confidence. The seismic data and well data indicate the presence of a significant velocity gradient, increasing to the southwest, between the MLE–1 and MZL–1 wells. A velocity map with a linear gradient was used for depth conversion, but it is poorly constrained. Three lines oriented northeast to southwest tie the MLE–1 area to the MZL–1 area. They are located above a significant strike-slip fault that is responsible for most of the structural features in the area. As such, they may suffer from out-of-plane events that could only be eliminated with three-dimensional (3–D) data. The faulting is clearly important to the structure, but the seismic data are inadequate to delineate the proper orientation or extent of faulting. Two depth maps were made from the seismic data: the TAGI and the Frasnian. The Frasnian map was shifted upward using the appropriate isopach thickness to form the depth maps for the reservoirs below the Hercynian unconformity. The subcrop of the F1 sand on the unconformity was mapped using an interpretation provided by First Calgary (Figure 3).

The TAGI depth map indicates a faulted four-way closure at the MLE–1 well, with a lowest closing contour that is consistent with the water level seen in the well for a structure filled to spillpoint. Over the rest of the area there is a southwest-plunging nose at the TAGI level. Below the Hercynian unconformity, there are two separate, faulted four-way closures at each of

the wells, and there is the possibility of a third closure northeast of the MZL–1 well. The observed structural closure at the MZL–1 well is not sufficient to explain the lowest known gas (LKG) in the F6, so a fault or pinch-out boundary was extended along the fault trend northeast of the well to explain a deeper closure. Similarly, repeat formation test (RFT) data at MLE–1 indicate a deeper gas/water contact (GWC), 3,139 meters TVDSS, for the F1 sand than can be mapped with structural closure. The fault northeast of the well was extended to explain the contact.

Volume in Place

Five horizons were mapped for volumetrics in this evaluation: the TAGI, F1, F6–1, F6–2, and F6–3. Volumes were estimated for the areas around each well. The TAGI in the area of MLE–1 well was mapped to an LKG at 2,944 meters TVDSS. The highest known water (HKW) is at 2,950 meters TVDSS in the well. The reserves associated with volumes in this segment were divided into proved, probable, and possible. Proved reserves were associated with volumes limited to the LKG and within an areal limit of high confidence based on seismic and geological interpretation. Reserves associated with the remaining volume below the LKG were divided evenly between probable and possible.

The MZL–1 well had a net pay of 18.6 meters in the TAGI, and the LKG is at 3,222 meters TVDSS; however, there does not appear to be structural closure for this column of gas. Since the estimated pay in this well is similar to the net pay in the tested MLE–1 well, a permeability barrier was placed about 1 kilometer to the east of the MZL–1 well as a means of defining closure. This may be due to a facies change, potentially involving an increase in clay content. Seismic data do not indicate faulting that would otherwise create a structural trap. Reserves associated with the volume mapped within this closure were classified as proved based on the similarity to the tested interval in MLE–1. Two additional barriers at 2 kilometers and 3 kilometers, respectively, to the east of the MZL–1 well have been mapped. Reserves associated with the volumes in these two areas were classified as probable (volume mapped between 1 and 2 kilometers east of the well) and possible (volume mapped between 2 and 3 kilometers east of the well).

The remaining portion of the TAGI involves small closures with no well control in the central area between the MZL–1 and the MLE–1 wells. Gas was mapped to the limit of structural closure. The lowest possible gas in the western structure was set at 3,064 meters TVDSS. The lowest

possible gas in the eastern structure was set at 3,025 meters TVDSS. Reserves associated with all mapped volumes for these two structures were classified as possible.

The F1 horizon is a combination of two stratigraphic levels that are in pressure communication, so the Carboniferous Tournasian was mapped in combination with the underlying Devonian Strunian. An LKG was picked in the MLE–1 well at 3,089 meters TVDSS. The lowest closing contour on the structure from seismic data is 3,100 meters TVDSS. Based on RFT data from the MLE–1 well, a potential GWC was estimated at 3,139 meters TVDSS. The RFT data used a water gradient defined in the TAGI, as no pressure data in the Tournasian/Strunian water column was available. Since the apparent GWC derived from the RFT plot is well below the seismically derived closure, a fault was used to provide adequate closure down to the GWC.

Reserves associated with mapped volume on the west side of this fault, in the vicinity of the MLE–1 well, were classified as proved down to the LKG at 3,089 meters TVDSS. Probable reserves were associated with volumes mapped on the east side of the fault down to the lowest closing contour at 3,100 meters TVDSS. Probable reserves were also associated with volumes mapped on the western block between the LKG at 3,089 meters TVDSS and 3,100 meters TVDSS. Possible reserves were associated with volumes mapped down to the GWC picked from the RFT plot at 3,139 meters TVDSS.

The F6–1 reservoir was mapped to an LKG in the MLE–1 well at 3,963 meters TVDSS. An HKW was picked at 3,971 meters TVDSS. Reserves associated with the volume down to the LKG were classified as proved. Reserves associated with mapped volumes to the HKW were divided between probable and possible.

Additional volume for the F6–1 was mapped near the MZL–1 well. Because of uncertainties associated with the F6–1 well test and other data, reserves associated with the F6–1 volumes in the area surrounding the MZL–1 well were classified as possible. Volumes associated with possible reserves were limited vertically to a depth of 3,982 meters TVDSS. This is the lowest closing contour in the fault block. The adjacent fault block was mapped to a lowest closing contour at 3,975 meters TVDSS. Reserves associated with all mapped volumes in this area were classified as possible.

The F6–2 reservoir was mapped to an LKG at 4,083 meters TVDSS from the MLE–1 well. Reserves associated with all mapped volumes to the LKG were classified as proved. Sand immediately below this LKG is tight. The HKW in the well was picked at 4,108 meters TVDSS. Reserves associated with mapped volume to the HKW were classified as probable and possible.

Additional volume in the F6–2 was mapped in the area of the MZL–1 well. A GWC was established at 4,106 meters TVDSS. Reserves associated with all volumes mapped to the contact were classified as probable due to the lack of a test in this zone. The adjacent fault block to the east has gas associated with probable reserves mapped down to 4,083 meters TVDSS. Reserves associated with mapped volumes below 4,083 meters TVDSS, down to the lowest closing contour at 4,106 meters TVDSS, were classified as possible.

The deepest reservoir with pay of any classification is the F6–3. The MZL–1 well has 10.3 meters of gas pay, down to 4,200 meters TVDSS. Reserves associated with mapped volumes in this block were classified as possible.

Volumes were estimated with and without regard to the block boundaries. Approximately 90 percent of the volume in place is within the block boundary. For the purposes of this study, the entire in-place volume was considered when estimating recovery. There are no offset plans to develop competitive production, and the projected development plan will allow drainage that affects the entire in-place volume.

The original gas in place (OGIP) estimates associated with proved, probable, and possible reserves expressed in millions of cubic meters (MMm^3) and millions of cubic feet (MMcf) of wet gas, are as follows:

	OGIP Associated with Proved, Probable, and Possible Reserves			
	Full Field		**Block Only**	
	(MMm^3)	**(MMcf)**	**(MMm^3)**	**(MMcf)**
Proved	16,822	594,060	15,199	536,744
Probable*	19,314	682,063	17,889	631,740
Possible*	41,686	1,472,118	40,017	1,413,178

* Probable and possible volumes have not been adjusted to account for risk.

Table 3 shows the details of the estimation of OGIP.

CLASSIFICATION of RESERVES

Petroleum reserves included in this report are classified by degree of proof as proved, probable, or possible. Proved reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production under existing economic and operating conditions using prices and costs as of the date the estimate is made, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

Proved – Reserves that have been proved to a high degree of certainty by analysis of the producing history of a reservoir and/or by volumetric analysis of adequate geological and engineering data. Commercial productivity has been established by actual production, successful testing, or in certain cases by favorable core analyses and electrical-log interpretation when the producing characteristics of the formation are known from nearby fields. Volumetrically, the structure, areal extent, volume, and characteristics of the reservoir are well defined by a reasonable interpretation of adequate subsurface well control and by known continuity of hydrocarbon-saturated material above known fluid contacts, if any, or above the lowest known structural occurrence of hydrocarbons.

Developed – Reserves that are recoverable from existing wells with current operating methods and expenses.

Developed reserves include both producing and nonproducing reserves. Estimates of producing reserves assume recovery by existing wells producing from present completion intervals with normal operating methods and expenses. Developed nonproducing reserves are in reservoirs behind the casing or at minor depths below the producing zone and are considered proved by production from other wells in the field, by successful

drill-stem tests, or by core analyses from the particular zones. Nonproducing reserves require only moderate expense to be brought into production.

Undeveloped – Reserves that are recoverable from additional wells yet to be drilled.

Undeveloped reserves are those considered proved for production by reasonable geological interpretation of adequate subsurface control in reservoirs that are producing or proved by other wells but are not recoverable from existing wells. This classification of reserves requires drilling of additional wells, major deepening of existing wells, or installation of enhanced recovery or other facilities.

Reserves recoverable by enhanced recovery methods, such as injection of external fluids to provide energy not inherent in the reservoirs, may be classified as proved developed or proved undeveloped reserves depending upon the extent to which such enhanced recovery methods are in operation. These reserves are considered to be proved only in cases where a successful fluid-injection program is in operation, a pilot program indicates successful fluid injection, or information is available concerning the successful application of such methods in the same reservoir and it is reasonably certain that the program will be implemented.

Probable – Reserves susceptible of being proved that are based on reasonable evidence of producible hydrocarbons within the limits of a structure or reservoir above known or inferred fluid contacts but are defined to a lesser degree of certainty because of more limited well control and/or the lack of definitive production tests. Probable reserves may include extensions of proved reservoirs or other reservoirs that have not been tested at commercial rates of flow or reserves recoverable by enhanced recovery methods that have not yet been tested in the same reservoir or where there is reasonable uncertainty that the program will be implemented.

Possible – Reserves that may exist but are less well defined by well control than probable reserves. Possible reserves include those based largely on log interpretation and other evidence of hydrocarbon

saturation in zones behind the pipe in existing wells, possible extensions to proved and probable reserves areas where indicated by geophysical or geological studies, and those to be recovered by enhanced recovery methods where the data are insufficient to classify the reserves as proved or probable.

The extent to which probable and possible reserves ultimately may be reclassified as proved reserves is dependent upon future drilling, testing, and well performance. The degree of risk to be applied in evaluating probable and possible reserves is influenced by economic and technological factors as well as the time element. Probable reserves in this report are presented both before and after adjustment in consideration of these additional risks in order to make them comparable with proved reserves. Possible reserves in this report have not been adjusted in consideration of these additional risks and therefore are not comparable with proved reserves. Values for probable reserves in this report are presented both before and after adjustment in consideration of these additional risks in order to make them comparable with values for proved reserves.

ESTIMATION of RESERVES

Estimates of reserves were prepared by the use of standard geological and engineering methods generally accepted by the petroleum industry. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

When applicable, the volumetric method was used to estimate the OGIP. Structure maps were prepared to delineate each reservoir, and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation.

Estimates of ultimate recovery were obtained after applying recovery factors to OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. When applicable, material-balance and other engineering methods were used to estimate recovery factors. In such cases, an analysis of reservoir performance, including production rate, reservoir pressure, and gas-oil ratio behavior, was used in the estimation of reserves.

In certain cases, when the previously named methods could not be used, reserves were estimated by analogy with similar wells or reservoirs for which more complete data were available.

The reserves estimates presented herein are generally based on consideration of data available through November 16, 2001.

Gas volumes reported herein are wet gas and sales gas expressed at a temperature base of 60 degrees Fahrenheit (°F) and a pressure base of 14.7 pounds per square inch absolute (psia). Wet gas is defined as the total gas to be produced before reduction for volume loss due to fuel and flare consumption and before reduction for liquid removal. Sales gas is defined as wet gas after reduction for liquids removal during gas processing, flare, and estimated fuel usage.

Condensate and LPG volumes estimated herein are those to be recovered by passage through a separator and low-temperature plant.

Test data are available in three reservoirs: TAGI, F1, and F6–2. The tests indicated gas and condensate productivity in the TAGI and the F1, while the tests in F6–2 indicated dry gas only. Absolute open flow (AOF) rates were calculated for each test based on the rate trend established in the F1, the only test with sufficient data to calculate the back-pressure slope. The AOF rates calculated were 262 Mm^3/d (9.25 MMcf/d), 1,048 Mm^3/d (37 MMcf/d), and 191 Mm^3/d (6.76 MMcf/d) for TAGI, F1, and F6–2, respectively. The F6–1 was not tested but has the same estimated net pay as F6–2, so the same AOF was assigned to this reservoir for forecasting purposes. Initial production rates are estimated to be 50 percent of the AOF.

Fluid analyses were available for this report in the TAGI and F1 reservoirs. These analyses used fluid matching and characterization techniques. The F6 reservoir fluid characterization was based on the well-test information.

Since the license for Block 405B had only recently been granted to First Calgary at the time of this report, certain assumptions concerning development plans have been made. Any actual development plans will be subject to review by the Algerian Government and SONATRACH, the Algerian national petroleum company, but First Calgary has provided a range of development options that appears reasonable based on the information available at this time.

First Calgary anticipates that field development will require connection to sales points at Rhourde Chouf and Rhourde Nouss. Two separate gathering systems will be required at the field level to accommodate the gas-condensate production from TAGI and F1 along with the dry gas production from F6–1 and F6–2. Maximum gathering system design will allow 4,250 Mm^3/d (150 MMcf/d) of gas with condensate and 2,850 Mm^3/d (100 MMcf/d) of dry gas. The gas-condensate flowstream will go through a separator and low-temperature plant to extract LPG and C_{5+}(condensate). Three transport lines for gas, LPG, and condensate will take production to the sales-transfer point.

For estimates of deliverability, a plant inlet pressure of 500 psia will receive the gas-condensate production, while the dry

gas will go directly into the transport line. The gas from the plant outlet will be compressed to 1,300 psia for delivery into the gas transport line. In this system, a minimum flowing wellhead pressure (FWHP) will be 1,350 psia for the dry-gas wells and 550 psia for the gas-condensate wells. When the dry-gas wells are unable to produce at the minimum FWHP, compression will be installed that will lower the minimum FWHP to 550 psia in those wells also.

The proposed development plan calls for stimulation by fracture treatment of MLE–1 and further testing. Additional 3–D seismic data will be acquired to propose additional drilling locations. Proved reserves are limited to 30 years or less in this evaluation based on the contract period. A plan to adequately develop the reservoirs established by proved-plus-probable estimates of reserves would require 16 wells evenly split between dry-gas and gas-condensate wells. Peak rates limited to 7,100 Mm^3/d (250 MMcf/d) are expected. Proved reserves would require eight wells with the same peak-rate limitation. Well deliverability with and without fracture treatment was considered. Fractured wells were projected to have 2.5 times the deliverability of unfractured wells. All projections are based on wells being fracture treated.

Reserves were estimated by projecting a development of the volume in place for each classification within the constraints of the expected facilities and the 30-year life of the PSC. The same individual well-deliverability parameters were used in each classification. The number of wells expected to be drilled is proportional to the volume in place. Recovery ranges from 50 percent to 70 percent of the OGIP depending upon the reservoir. Projections for proved and proved-plus-probable reserves are shown in Tables 4 and 5.

Estimated gross proved, probable, and possible reserves, as of December 31, 2001, for Block 405B evaluated herein are summarized below in thousands of cubic meters (Mm^3) and thousands of barrels

(Mbbl) for condensate and LPG and millions of cubic meters (MMm^3) and millions of cubic feet (MMcf) for sales gas:

	Gross Reserves			
	Sales Gas		Condensate and LPG	
	(MMm^3)	(MMcf)	(Mm^3)	(Mbbl)
Proved	10,085	356,154	2,400	15,097
Probable*	13,958	492,921	2,177	13,696
Possible*	20,160	711,954	2,505	15,761

* Probable and possible reserves have not been adjusted for risk.

Proved, probable, and possible reserves have been estimated only for known accumulations in Block 405B and do not include any exploration potential. All proved reserves are undeveloped.

Risk-adjusted probable reserves have been estimated by applying a 50-percent probability to the unrisked probable reserves. The development of the proved-plus-risk-adjusted-probable reserves would require 16 wells just as in the unrisked projection. The projection for the risked reserves (shown in Table 6) reflects performance that would be somewhat less than that expected in the unrisked projection. Gross risk-adjusted probable reserves are 1,089 Mm^3 (6,849 Mbbl) for condensate and LPG and 6,979 MMm^3 (246,461 MMcf) for sales gas.

Net reserves have been estimated based on the terms of the PSC as discussed in the Valuation of Reserves section of this report. As such, the resulting net interests may vary with product price, actual costs, timing of production, and other factors. Proved and probable net reserves were estimated explicitly by evaluation of each respective projection. Possible net reserves are based on the net percentage calculated for probable reserves. In this report, First Calgary's net interests are 21.45, 13.86, and 13.86 percent for proved, probable, and possible reserves, respectively.

VALUATION of RESERVES

Revenue values in this report have been prepared using initial prices and costs and future price and cost assumptions specified by First Calgary. In this report, values for proved and proved-plus-probable reserves are based on projections of estimated future production and revenue prepared for these properties with and without risk adjustment applied to the probable reserves. Probable reserves involve higher risk than proved reserves.

Prices

Condensate, gas, and LPG prices used in this report were based on prevailing prices, as of December 31, 2001. No general escalation that might result from inflation was applied to prices.

Operating Costs

Operating costs and operating-cost forecasts provided by First Calgary were used in estimating future costs required to operate the fields. In certain situations, future costs, either higher or lower than current costs, may have been used because of anticipated changes in operating conditions. There has been no general escalation applied to operating costs to account for inflation. Abandonment expenses have not been considered in this evaluation.

Capital Costs

Future capital costs were estimated using current capital cost forecasts provided by First Calgary. Where necessary, these costs were scaled and adjusted to fit the scenario being evaluated. Drilling costs were estimated to be $4 to $6 million per well. Facility and pipeline costs were estimated to be $90 million. There has been no general escalation applied to capital costs to account for inflation.

Taxes

All taxes are paid by SONATRACH wholly out of SONATRACH's share from the PSC.

PSC Terms

First Calgary provided the terms for the PSC for Block 405B for this evaluation. Net reserves were based on First Calgary's profit share. Net reserves were estimated by applying the ratio of barrels of oil equivalent (boe) of the profit share and the gross boe projection to the gross reserves. Boe is based on a ratio of 6,000 cubic feet of gas to 1 barrel of oil, 1,423 cubic feet of gas per barrel of LPG, and 910 cubic feet of gas per barrel of condensate.

Partnership Participation

First Calgary initially pays 100 percent of the costs of exploration, including seismic acquisition, exploration drilling, and related studies. SONATRACH will reimburse First Calgary for 25 percent of the costs of exploration from SONATRACH's future share of production. First Calgary pays 75 percent of all other development and operating costs, with SONATRACH being responsible for the balance.

Profit Share

The contractor's maximum allowable share of revenue was limited to 49 percent of the total revenue. Contractor's share of the profit was based on a sliding-scale rate formula agreed in the PSC.

Future Net Revenue

Future net revenue is equivalent to First Calgary's portion of the profit share plus the reimbursement by SONATRACH of exploration costs paid by First Calgary less an "admission payment" to SONATRACH, capital expenditures, operating

costs (including training costs), and carried interest from First Calgary's share of remuneration from their profit share.

Economic projections for the proved, proved-plus-probable, and proved-plus-risk-adjusted-probable reserves, as of December 31, 2001, are presented in Tables 7, 8, and 9, respectively. Estimated future net revenue and present worth at various discount rates are summarized below, expressed in thousands of U.S. dollars (M U.S.$):

	Proved (M U.S.$)	**Proved Plus Probable* (M U.S.$)**	**Proved plus Risk-Adjusted Probable (M U.S.$)**
Future Net Revenue	166,204	332,192	253,194
Present Worth at 10 Percent	81,055	153,600	118,742
Present Worth at 15 Percent	54,961	103,280	79,549
Present Worth at 20 Percent	35,967	68,095	51,770

* Revenue derived from probable reserves has not been adjusted for risk unless otherwise noted.

SUMMARY and CONCLUSIONS

First Calgary has entered into an agreement with the Algerian Government to explore, appraise, and develop Block 405B in the Berkine basin of Algeria. The field will produce gas, condensate, and LPG from multiple zones, with gas-sales points that are projected to be at the Rhourde Nouss and Rhourde Chouf fields. Information used in this report was supplied by First Calgary based on its final PSC.

The estimated gross and net proved (all undeveloped), probable, and possible reserves, as of December 31, 2001, of the properties evaluated in this report are summarized below, expressed in thousands of cubic meters (Mm^3), thousands of barrels (Mbbl), millions of cubic meters (MMm^3), and millions of cubic feet (MMcf):

	Gross Reserves				Net Reserves			
	Sales Gas		Condensate and LPG		Sales Gas		Condensate and LPG	
	(MMm^3)	(MMcf)	(Mm^3)	(Mbbl)	(MMm^3)	(MMcf)	(Mm^3)	(Mbbl)
Proved	10,085	356,154	2,400	15,097	2,164	76,411	515	3,239
Probable*	13,958	492,921	2,177	13,696	1,934	68,316	302	1,898
Possible*	20,160	711,954	2,505	15,761	2,794	98,672	347	2,184

* Probable and possible reserves have not been adjusted for risk.

The gross risk-adjusted probable reserves are 1,089 Mm^3 (6,849 Mbbl) for condensate and LPG and 6,979 MMm^3 (246,461 MMcf) for sales gas.

Estimated revenue and present worth attributable to the net interests in the proved and proved-plus-probable reserves as of December 31, 2001, evaluated in this report are summarized below, expressed in thousands of U.S. dollars (M U.S.$):

	Proved (M U.S.$)	Proved Plus Probable* (M U.S.$)	Proved plus Risk-Adjusted Probable (M U.S.$)
Future Net Revenue	166,204	332,192	253,194
Present Worth at 10 Percent	81,055	153,600	118,742
Present Worth at 15 Percent	54,961	103,280	79,549
Present Worth at 20 Percent	35,967	68,095	51,770

* Revenue derived from probable reserves has not been adjusted for risk unless otherwise noted.

Gas volumes reported herein are expressed at a temperature base of 60 °F and a pressure base of 14.7 psia.

Professional Qualifications

DeGolyer and MacNaughton is a Delaware corporation with offices at 4925 Greenville Avenue, Suite 400, Dallas, Texas 75206, U.S.A. The firm has been providing petroleum consulting services throughout the world for more than 60 years. The firm's professional engineers, geologists, geophysicists, petrophysicists, and economists are engaged in the independent appraisal of oil and gas properties, evaluation of hydrocarbon and other mineral prospects, basin evaluations, comprehensive field studies, equity studies, and studies of supply and economics related to the energy industry. Except for the provision of professional services on a fee basis, DeGolyer and MacNaughton has no commercial arrangement with any other person or company involved in the interests which are the subject of this report.

The evaluation has been supervised by Mr. Robert A. Cooksey. Mr. Cooksey is a Senior Vice President with DeGolyer and MacNaughton, Manager of the firm's Europe-Middle East-Africa Division, a Registered Professional Engineer in the State of Texas, and a member of the Society of Petroleum Engineers. He has 40 years of oil and gas industry experience.

Submitted,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON

SIGNED: June 7, 2002

Robert A. Cooksey, P.E.

Robert A. Cooksey, P.E.
Senior Vice President
DeGolyer and MacNaughton

CERTIFICATE of QUALIFICATION

I, Robert A. Cooksey, Petroleum Engineer with DeGolyer and MacNaughton, 4925 Greenville Ave., Dallas, Texas, U.S.A., hereby certify:

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which company did prepare the report entitled "Appraisal Report as of December 31, 2001, on Block 405B in Algeria for First Calgary Petroleums Ltd. Canadian Policy 2B Case," dated June 7, 2002, and that I, as Senior Vice President, was responsible for the preparation of this report.

2. That I attended the University of Kansas, and that I graduated with Bachelor of Science and Master of Science degrees in Petroleum Engineering in the year 1962; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the International Society of Petroleum Engineers; and that I have in excess of forty (40) years of experience in oil and gas reservoir studies and evaluations.

3. That DeGolyer and MacNaughton or its officers have no direct or indirect interest, nor do they expect to receive any direct or indirect interest in any properties or securities of First Calgary Petroleums Ltd. or affiliate thereof.

4. That the aforementioned report was not based on a personal field examination of the properties in question; however, such an examination was not deemed necessary in view of the extent and accuracy of the information available.

Robert A. Cooksey, P.E.

Robert A. Cooksey, P.E.
Senior Vice President
DeGolyer and MacNaughton

June 7, 2002

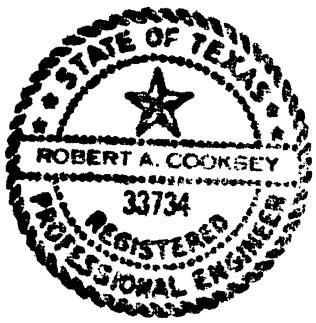

TABLE 1
GROSS and NET RESERVES
as of
DECEMBER 31, 2001
attributable to
FIRST CALGARY PETROLEUMS LTD.
for
BLOCK 405B
ALGERIA

CANADIAN POLICY 2B CASE

	Gross				Net			
	Sales Gas		Condensate and LPG		Sales Gas		Condensate and LPG	
	(MMm^3)	(MMcf)	(Mm^3)	(Mbbl)	(MMm^3)	(MMcf)	(Mm^3)	(Mbbl)
Proved Developed	0	0	0	0	0	0	0	0
Proved Undeveloped	10,085	356,154	2,400	15,097	2,164	76,411	515	3,239
Total Proved	**10,085**	**356,154**	**2,400**	**15,097**	**2,164**	**76,411**	**515**	**3,239**
Probable	13,958	492,921	2,177	13,696	1,934	68,316	302	1,898
Possible	20,160	711,954	2,505	15,761	2,794	98,672	347	2,184

Note: Probable and possible reserves have not been adjusted for risk.

TABLE 2
FUTURE NET REVENUE
as of
DECEMBER 31, 2001
attributable to
FIRST CALGARY PETROLEUMS LTD.
for
BLOCK 405B
ALGERIA

CANADIAN POLICY 2B CASE

	Future Net Revenue (M U.S.$)	Present Worth at 10 Percent (M U.S.$)	Present Worth at 15 Percent (M U.S.$)	Present Worth at 20 Percent (M U.S.$)
Proved	166,204	81,055	54,961	35,967
Proved plus Risk-Adjusted Probable	253,194	118,742	79,549	51,770
Proved plus Probable	332,192	153,600	103,280	68,095

Note: Values associated with probable reserves have not been adjusted for risk unless otherwise noted.

TABLE 3
RESERVOIR PARAMETERS and ORIGINAL GAS in PLACE
as of
DECEMBER 31, 2001
for
BLOCK 405B
ALGERIA

CANADIAN POLICY 2B CASE

	Proved				Probable				Possible				
	TAGI	F1	F6–1	F6–2	TAGI	F1	F6–1	F6–2	TAGI	F1	F6–1	F6–2	F6–3
Initial Pressure, psig	5,000	5,230	7,000	7,000	5,000	5,230	7,000	7,000	5,000	5,230	7,000	7,000	7,000
Gas Formation Volume Factor, svol/rvol	258	275	286	286	258	275	286	286	258	275	286	286	286
Reservoir Temperature, °F	228	239	273	273	228	239	273	273	228	239	273	273	273
Net Rock Volume, Mm^3	165,495	82,830	229,756	215,369	105,321	118,866	20,969	475,075	132,398	115,742	1,192,562	273,456	80,882
Average Porosity, decimal	0.153	0.170	0.110	0.127	0.153	0.170	0.110	0.140	0.153	0.170	0.107	0.139	0.127
Average Water Saturation, decimal	0.333	0.411	0.276	0.367	0.333	0.411	0.276	0.329	0.333	0.411	0.290	0.333	0.376
Original Gas in Place, Mm^3	4,356,560	2,280,786	5,233,162	4,951,727	2,772,713	3,273,064	477,612	12,790,397	3,485,628	3,187,043	25,933,305	7,247,019	1,833,185
Original Gas in Place, MMcf	153,847	80,544	184,804	174,865	97,918	115,588	16,867	451,690	123,093	112,549	915,816	255,922	64,738

Notes:
1. This table is a compilation of several calculations. The reservoir parameters shown are averages.
2. The volumes in this table are not constrained by block boundaries. Volumes within Block 405B may be less than indicated in this table.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

TABLE 4
PROVED PRODUCTION FORECAST
as of
DECEMBER 31, 2001
for the
BLOCK 405B
ALGERIA

CANADIAN POLICY 2B CASE

Year	Annual Sales-Gas Deliveries (MMcf)	Shrinkage (%)	Annual Wet-Gas Production (MMcf)	Annual LPG Recovery (Mbbl)	Annual Condensate Recovery (Mbbl)	Number of Wells
2002	0	0.0	0	0	0	0
2003	0	0.0	0	0	0	0
2004	0	0.0	0	0	0	0
2005	64,510	11.6	73,000	463	3,363	7
2006	65,167	10.7	73,000	575	2,749	8
2007	56,418	10.1	62,773	552	2,061	8
2008	46,835	8.1	50,986	517	1,506	8
2009	35,418	7.3	38,219	356	979	8
2010	27,479	6.6	29,430	245	668	8
2011	21,747	6.0	23,125	166	463	8
2012	17,590	5.3	18,565	112	322	8
2013	11,048	1.0	11,160	0	0	4
2014	9,942	1.0	10,042	0	0	4
2015	0	0.0	0	0	0	0
2016	0	0.0	0	0	0	0
2017	0	0.0	0	0	0	0
2018	0	0.0	0	0	0	0
2019	0	0.0	0	0	0	0
2020	0	0.0	0	0	0	0
2021	0	0.0	0	0	0	0
2022	0	0.0	0	0	0	0
2023	0	0.0	0	0	0	0
2024	0	0.0	0	0	0	0
Total (MMcf) or (Mbbl)	**356,154**		**390,300**	**2,986**	**12,111**	
Total (MMm^3) or (Mm^3)	**10,085**		**11,052**	**475**	**1,925**	

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

TABLE 5
PROVED-PLUS-PROBABLE PRODUCTION FORECAST
as of
DECEMBER 31, 2001
for the
BLOCK 405B
ALGERIA

CANADIAN POLICY 2B CASE

Year	Annual Sales-Gas Deliveries (MMcf)	Shrinkage (%)	Annual Wet-Gas Production (MMcf)	Annual LPG Recovery (Mbbl)	Annual Condensate Recovery (Mbbl)	Number of Wells
2002	0	0.00	0	0	0	0
2003	0	0.00	0	0	0	0
2004	0	0.00	0	0	0	0
2005	78,375	14.11	91,250	683	5,265	9
2006	80,214	12.09	91,250	755	4,056	13
2007	81,227	10.98	91,250	800	3,410	15
2008	81,835	10.32	91,250	832	3,024	16
2009	83,280	8.73	91,250	942	2,801	16
2010	81,886	6.31	87,400	684	1,878	16
2011	63,680	5.63	67,481	460	1,260	16
2012	50,542	5.00	53,200	306	861	16
2013	41,490	4.26	43,337	199	577	16
2014	28,694	1.00	28,984	0	0	8
2015	25,795	1.00	26,056	0	0	8
2016	23,337	1.00	23,573	0	0	8
2017	21,227	1.00	21,441	0	0	8
2018	19,399	1.00	19,595	0	0	8
2019	17,793	1.00	17,973	0	0	8
2020	16,368	1.00	16,533	0	0	8
2021	15,094	1.00	15,246	0	0	8
2022	13,948	1.00	14,089	0	0	8
2023	12,915	1.00	13,045	0	0	8
2024	11,976	1.00	12,097	0	0	8
Total (MMcf) or (Mbbl)	**849,075**		**904,203**	**5,661**	**23,132**	
Total (MMm^3) or (Mm^3)	**24,043**		**25,604**	**900**	**3,677**	

Note: Probable reserves have not been adjusted for risk.

TABLE 6
PROVED-PLUS-RISK-ADJUSTED-PROBABLE PRODUCTION FORECAST
as of
DECEMBER 31, 2001
for the
BLOCK 405B
ALGERIA

CANADIAN POLICY 2B CASE

Year	Annual Sales-Gas Deliveries (MMcf)	Shrinkage (%)	Annual Wet-Gas Production (MMcf)	Annual LPG Recovery (Mbbl)	Annual Condensate Recovery (Mbbl)	Number of Wells
2002	0	0.00	0	0	0	0
2003	0	0.00	0	0	0	0
2004	0	0.00	0	0	0	0
2005	72,136	12.99	82,905	579	4,358	9
2006	73,443	11.48	82,968	671	3,437	13
2007	70,492	10.60	78,850	688	2,790	15
2008	66,085	9.35	72,901	658	2,270	16
2009	61,742	8.10	67,184	623	1,762	16
2010	60,123	6.45	64,268	477	1,265	16
2011	46,907	5.77	49,779	307	858	16
2012	37,361	5.11	39,373	206	507	16
2013	29,313	2.89	30,185	115	375	16
2014	21,193	1.00	21,407	0	0	8
2015	15,477	1.00	15,633	0	0	8
2016	14,002	1.00	14,143	0	0	8
2017	12,736	1.00	12,865	0	0	8
2018	11,639	1.00	11,757	0	0	4
2019	9,966	1.00	10,067	0	0	4
2020	0	1.00	0	0	0	0
2021	0	1.00	0	0	0	0
2022	0	1.00	0	0	0	0
2023	0	1.00	0	0	0	0
2024	0	1.00	0	0	0	0
Total (MMcf) or (Mbbl)	**602,615**		**654,285**	**4,324**	**17,622**	
Total (MMm^3) or (Mm^3)	**17,064**		**18,527**	**687**	**2,802**	

Note: Probable volumes have been adjusted for risk based on a 50-percent probability.

TABLE 7
FUTURE NET REVENUE
from
PROVED RESERVES
as of
DECEMBER 31, 2001
for
BLOCK 405B
ALGERIA

CANADIAN POLICY 2B CASE

	Gross Production								First Calgary Net										
Year	Sales Gas (MMcf)	LPG (Mbbl)	Condensate (Mbbl)	Total (Mboe)	Effective Price (U.S.$/boe)	Gross Revenue (M U.S.$)	Contractor's Profit Share (fraction)	Contractor's Entitlement (Mboe)	Entitlement (Mboe)	Profit Share (M U.S.$)	Payments From SH (M U.S.$)	Payments to SH (M U.S.$)	Carried Interest (M U.S.$)	Operating Cost (M U.S.$)	Training Cost (M U.S.$)	Development Capital (M U.S.$)	Exploration Capital (M U.S.$)	Future Net Revenue (M U.S.$)	Present Worth at 10 Percent (M U.S.$)
2002	0	0	0	0	0.00	0	0.000	0	0	0	0	0	0	0	150	0	450	(600)	(569)
2003	0	0	0	0	0.00	0	0.000	0	0	0	0	1,778	0	0	150	5,333	9,413	(16,674)	(14,307)
2004	0	0	0	0	0.00	0	0.000	0	0	0	0	15,105	0	0	150	60,031	0	(75,286)	(58,475)
2005	64,510	463	3,363	11,372	26.51	301,417	0.361	4,109	3,082	81,683	493	0	0	4,933	150	19,938	0	57,155	40,184
2006	65,167	575	2,749	11,414	25.71	293,448	0.361	4,124	3,093	79,511	493	0	1,833	4,933	150	2,850	0	70,238	44,702
2007	56,418	552	2,061	9,846	25.25	248,645	0.364	3,580	2,685	67,810	493	0	3,161	4,933	150	0	0	60,059	34,600
2008	46,835	517	1,506	8,157	24.93	203,369	0.335	2,735	2,051	51,137	493	0	2,327	4,933	150	0	0	44,220	23,061
2009	35,418	356	979	6,136	24.44	149,964	0.174	1,068	801	19,569	493	0	749	4,933	150	0	0	14,230	6,718
2010	27,479	245	668	4,739	24.05	113,956	0.140	662	497	11,931	0	0	342	4,933	150	0	0	6,506	2,780
2011	21,747	166	463	3,734	23.67	88,369	0.140	521	391	9,252	0	0	208	4,933	150	0	0	3,961	1,532
2012	17,590	112	322	3,007	23.29	70,025	0.140	420	315	7,332	0	0	112	4,933	150	0	0	2,137	748
2013	11,048	0	0	1,841	21.00	38,668	0.140	257	193	4,049	0	0	13	3,640	150	0	0	246	78
2014	9,942	0	0	1,657	21.00	34,797	0.140	231	173	3,643	0	0	1	3,480	150	0	0	12	3
2015	0	0	0	0	0.00	0	0.000	0	0	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0.00	0	0.000	0	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0.00	0	0.000	0	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0.00	0	0.000	0	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0.00	0	0.000	0	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0.00	0	0.000	0	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0.00	0	0.000	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0.00	0	0.000	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0.00	0	0.000	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0.00	0	0.000	0	0	0	0	0	0	0	0	0	0	0	0
Total	**356,154**	**2,986**	**12,111**	**61,903**		**1,542,658**		**17,707**	**13,281**	**335,917**	**2,465**	**16,883**	**8,746**	**46,584**	**1,950**	**88,152**	**9,863**	**166,204**	**81,055**

Present Worth at	(M U.S.$)
10 Percent	81,055
15 Percent	54,961
20 Percent	35,967

TABLE 8
FUTURE NET REVENUE
from
PROVED-PLUS-PROBABLE RESERVES
as of
DECEMBER 31, 2001
for
BLOCK 405B
ALGERIA

CANADIAN POLICY 2B CASE

	Gross Production								First Calgary Net										
Year	Sales Gas (MMcf)	LPG (Mbbl)	Condensate (Mbbl)	Total (Mboe)	Effective Price (U.S.$/boe)	Gross Revenue (M U.S.$)	Contractor's Profit Share (fraction)	Contractor's Entitlement (Mboe)	Entitlement (Mboe)	Profit Share (M U.S.$)	Payments From SH (M U.S.$)	Payments to SH (M U.S.$)	Carried Interest (M U.S.$)	Operating Cost (M U.S.$)	Training Cost (M U.S.$)	Development Capital (M U.S.$)	Exploration Capital (M U.S.$)	Future Net Revenue (M U.S.$)	Present Worth at 10 Percent (M U.S.$)
2002	0	0	0	0	0.00	0	0.000	0	0	0	0	0	0	0	150	0	450	(600)	(569)
2003	0	0	0	0	0.00	0	0.000	0	0	0	0	2,128	0	0	150	6,383	9,413	(18,074)	(15,508)
2004	0	0	0	0	0.00	0	0.000	0	0	0	0	14,755	0	0	150	82,216	0	(97,121)	(75,434)
2005	78,375	683	5,265	14,023	27.95	391,966	0.359	5,028	3,771	105,397	493	0	0	5,975	150	30,452	0	69,313	48,732
2006	80,214	755	4,056	14,163	26.51	375,507	0.358	5,076	3,807	100,938	493	0	1,862	5,975	150	11,588	0	81,856	52,096
2007	81,227	800	3,410	14,245	25.76	366,937	0.358	5,104	3,828	98,616	493	0	4,480	5,975	150	3,375	0	85,129	49,044
2008	81,835	832	3,024	14,295	25.32	361,917	0.358	5,122	3,842	97,255	493	0	4,581	5,975	150	0	0	87,042	45,392
2009	83,280	942	2,801	14,528	25.09	364,493	0.191	2,769	2,077	52,104	493	0	2,324	5,975	150	0	0	44,148	20,841
2010	81,886	684	1,878	14,095	23.87	336,499	0.128	1,811	1,358	32,421	0	0	1,315	5,975	150	0	0	24,981	10,675
2011	63,680	460	1,260	10,914	23.49	256,377	0.132	1,440	1,080	25,372	0	0	962	5,975	150	0	0	18,285	7,073
2012	50,542	306	861	8,627	23.14	199,637	0.136	1,174	881	20,370	0	0	712	5,975	150	0	0	13,533	4,739
2013	41,490	199	577	7,050	22.74	160,345	0.140	984	738	16,788	0	0	533	5,975	150	0	0	10,130	3,211
2014	28,694	0	0	4,782	21.00	100,429	0.140	668	501	10,515	0	0	220	5,975	150	0	0	4,170	1,196
2015	25,795	0	0	4,299	21.00	90,283	0.140	600	450	9,453	0	0	166	5,975	150	0	0	3,162	821
2016	23,337	0	0	3,890	21.00	81,680	0.140	543	407	8,552	0	0	121	5,975	150	0	0	2,306	542
2017	21,227	0	0	3,538	21.00	74,295	0.140	494	371	7,779	0	0	83	5,975	150	0	0	1,571	334
2018	19,399	0	0	3,233	21.00	67,897	0.140	451	338	7,109	0	0	55	5,850	150	0	0	1,054	203
2019	17,793	0	0	2,966	21.00	62,276	0.140	414	311	6,520	0	0	38	5,620	150	0	0	712	124
2020	16,368	0	0	2,728	21.00	57,288	0.140	381	286	5,998	0	0	17	5,510	150	0	0	321	51
2021	15,094	0	0	2,516	21.00	52,829	0.140	351	263	5,531	0	0	8	5,225	150	0	0	148	21
2022	13,948	0	0	2,325	21.00	48,818	0.140	325	244	5,111	0	0	6	4,850	150	0	0	105	14
2023	12,915	0	0	2,153	21.00	45,203	0.140	300	225	4,733	0	0	1	4,570	150	0	0	12	1
2024	11,976	0	0	1,996	21.00	41,916	0.140	279	209	4,389	0	0	0	4,230	150	0	0	9	1
Total	**849,075**	**5,661**	**23,132**	**146,366**		**3,536,592**		**33,314**	**24,987**	**624,951**	**2,465**	**16,883**	**17,484**	**113,530**	**3,450**	**134,014**	**9,863**	**332,192**	**153,600**

Note: There has been no adjustment applied to the probable reserves or the value of the probable reserves to account for risk.

Present Worth at (M U.S.$)	
10 Percent	153,600
15 Percent	103,280
20 Percent	68,095

TABLE 9
FUTURE NET REVENUE
from
PROVED-PLUS-RISK-ADJUSTED PROBABLE RESERVES
as of
DECEMBER 31, 2001
for
BLOCK 405B
ALGERIA

CANADIAN POLICY 2B CASE

	Gross Production								First Calgary Net										
Year	Sales Gas (MMcf)	LPG (Mbbl)	Condensate (Mbbl)	Total (Mboe)	Effective Price (U.S.$/boe)	Gross Revenue (M U.S.$)	Contractor's Profit Share (fraction)	Contractor's Entitlement (Mboe)	Entitlement (Mboe)	Profit Share (M U.S.$)	Payments From SH (M U.S.$)	Payments to SH (M U.S.$)	Carried Interest (M U.S.$)	Operating Cost (M U.S.$)	Training Cost (M U.S.$)	Development Capital (M U.S.$)	Exploration Capital (M U.S.$)	Future Net Revenue (M U.S.$)	Present Worth at 10 Percent (M U.S.$)
2002	0	0	0	0	0.00	0	0.000	0	0	0	0	0	0	0	150	0	450	(600)	(569)
2003	0	0	0	0	0.00	0	0.000	0	0	0	0	2,090	0	0	150	6,271	9,413	(17,924)	(15,379)
2004	0	0	0	0	0.00	0	0.000	0	0	0	0	14,793	0	0	150	74,988	0	(89,931)	(69,849)
2005	72,136	579	4,358	12,821	27.31	350,107	0.360	4,611	3,458	94,438	493	0	0	5,975	150	25,550	0	63,256	44,474
2006	73,443	671	3,437	12,921	26.15	337,910	0.360	4,646	3,485	91,122	493	0	1,576	5,975	150	8,775	0	75,139	47,821
2007	70,492	688	2,790	12,335	25.53	314,941	0.360	4,443	3,332	85,074	493	0	3,803	5,975	150	3,375	0	72,264	41,632
2008	66,085	658	2,270	11,515	25.06	288,571	0.361	4,158	3,119	78,162	493	0	3,627	5,975	150	0	0	68,903	35,933
2009	61,742	623	1,762	10,705	24.53	262,575	0.224	2,395	1,796	44,066	493	0	1,922	5,975	150	0	0	36,512	17,236
2010	60,123	477	1,265	10,325	23.66	244,334	0.133	1,372	1,029	24,341	0	0	911	5,975	150	0	0	17,305	7,395
2011	46,907	307	858	8,021	23.30	186,872	0.138	1,103	827	19,275	0	0	658	5,975	150	0	0	12,492	4,832
2012	37,361	206	507	6,353	22.76	144,619	0.140	887	665	15,142	0	0	451	5,975	150	0	0	8,566	2,999
2013	29,313	115	375	4,970	22.57	112,170	0.140	694	521	11,744	0	0	281	5,975	150	0	0	5,338	1,692
2014	21,193	0	0	3,532	21.00	74,176	0.140	493	370	7,766	0	0	82	5,975	150	0	0	1,559	447
2015	15,477	0	0	2,580	21.00	54,170	0.140	360	270	5,672	0	0	11	5,300	150	0	0	211	55
2016	14,002	0	0	2,334	21.00	49,007	0.140	326	245	5,131	0	0	4	4,900	150	0	0	77	18
2017	12,736	0	0	2,123	21.00	44,576	0.140	296	222	4,667	0	0	1	4,500	150	0	0	16	3
2018	11,639	0	0	1,940	21.00	40,737	0.140	271	203	4,265	0	0	0	4,106	150	0	0	9	2
2019	9,966	0	0	1,661	21.00	34,881	0.140	232	174	3,652	0	0	0	3,500	150	0	0	2	0
2020	0	0	0	0	0.00	0	0.000	0	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0.00	0	0.000	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0.00	0	0.000	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0.00	0	0.000	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0.00	0	0.000	0	0	0	0	0	0	0	0	0	0	0	0
Total	**602,615**	**4,324**	**17,622**	**104,136**		**2,539,646**		**26,287**	**19,716**	**494,517**	**2,465**	**16,883**	**13,327**	**82,056**	**2,700**	**118,959**	**9,863**	**253,194**	**118,742**

Note: Probable volumes have been adjusted for risk based on a 50-percent probability.

Present Worth at	(M U.S.$)
10 Percent	118,742
15 Percent	79,549
20 Percent	51,770

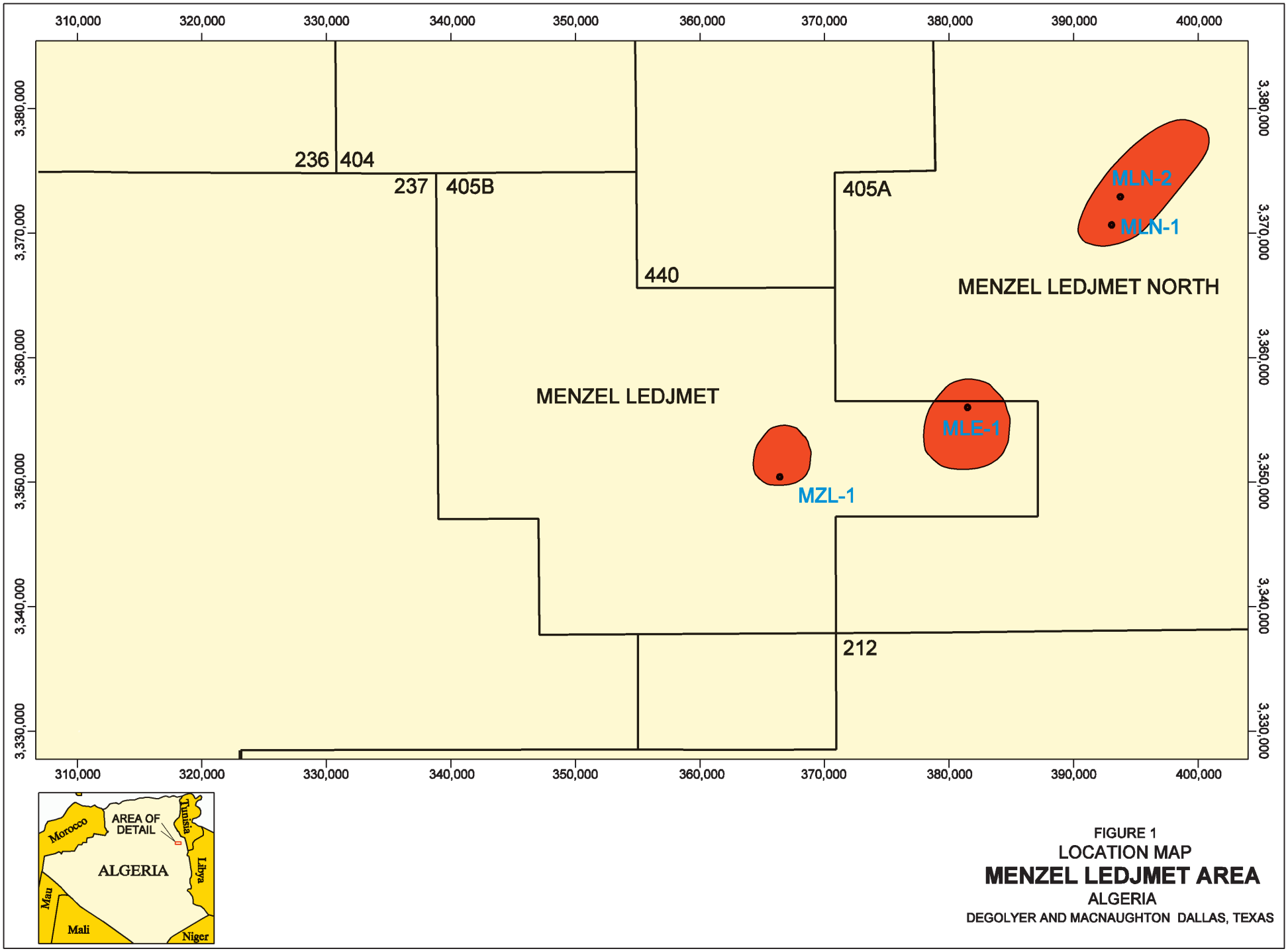

FIGURE 1

LOCATION MAP

MENZEL LEDJMET AREA

ALGERIA

DEGOLYER AND MACNAUGHTON DALLAS, TEXAS

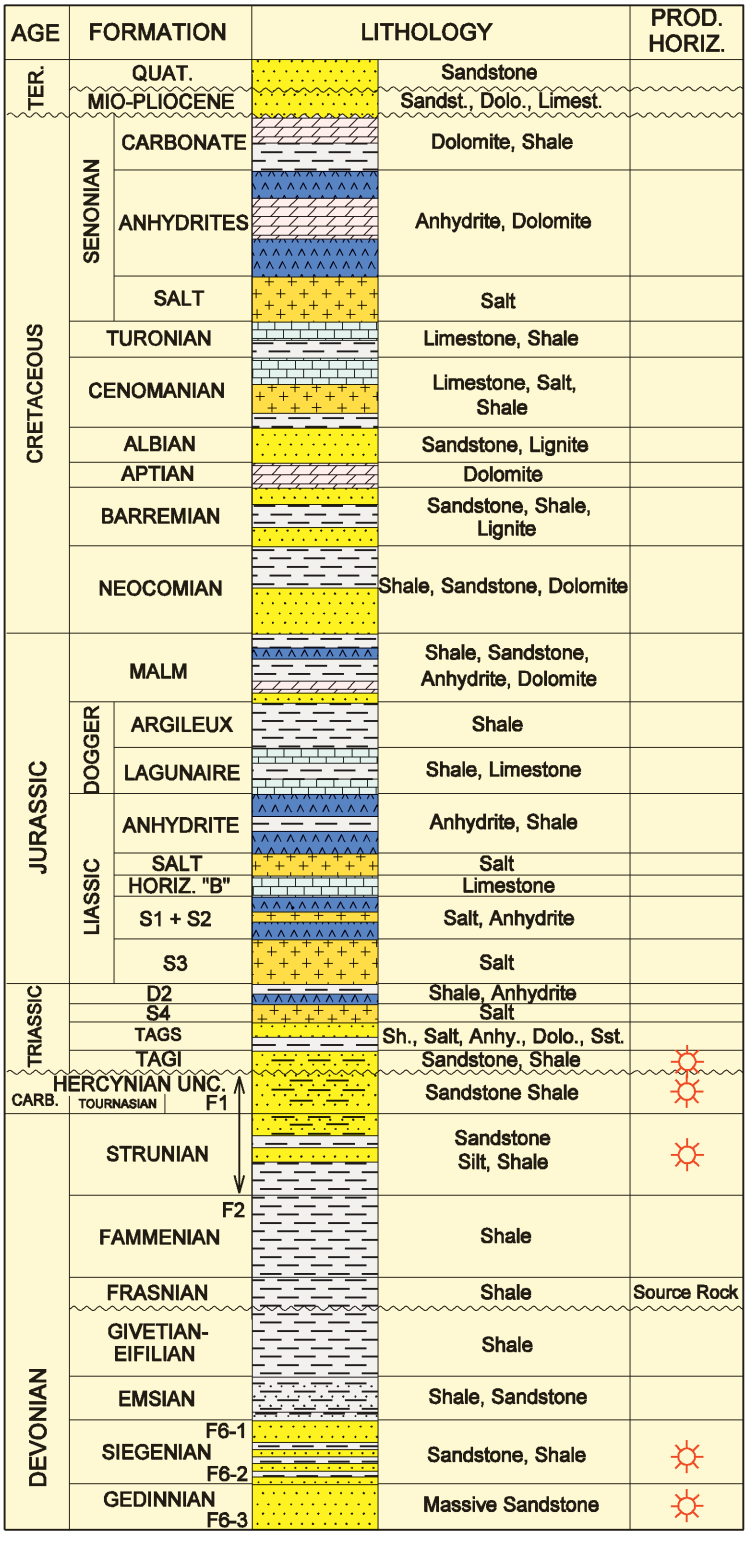

FIGURE 2

STRATIGRAPHIC COLUMN

MENZEL LEDJMET AREA

ALGERIA

DEGOLYER AND MACNAUGHTON DALLAS, TEXAS

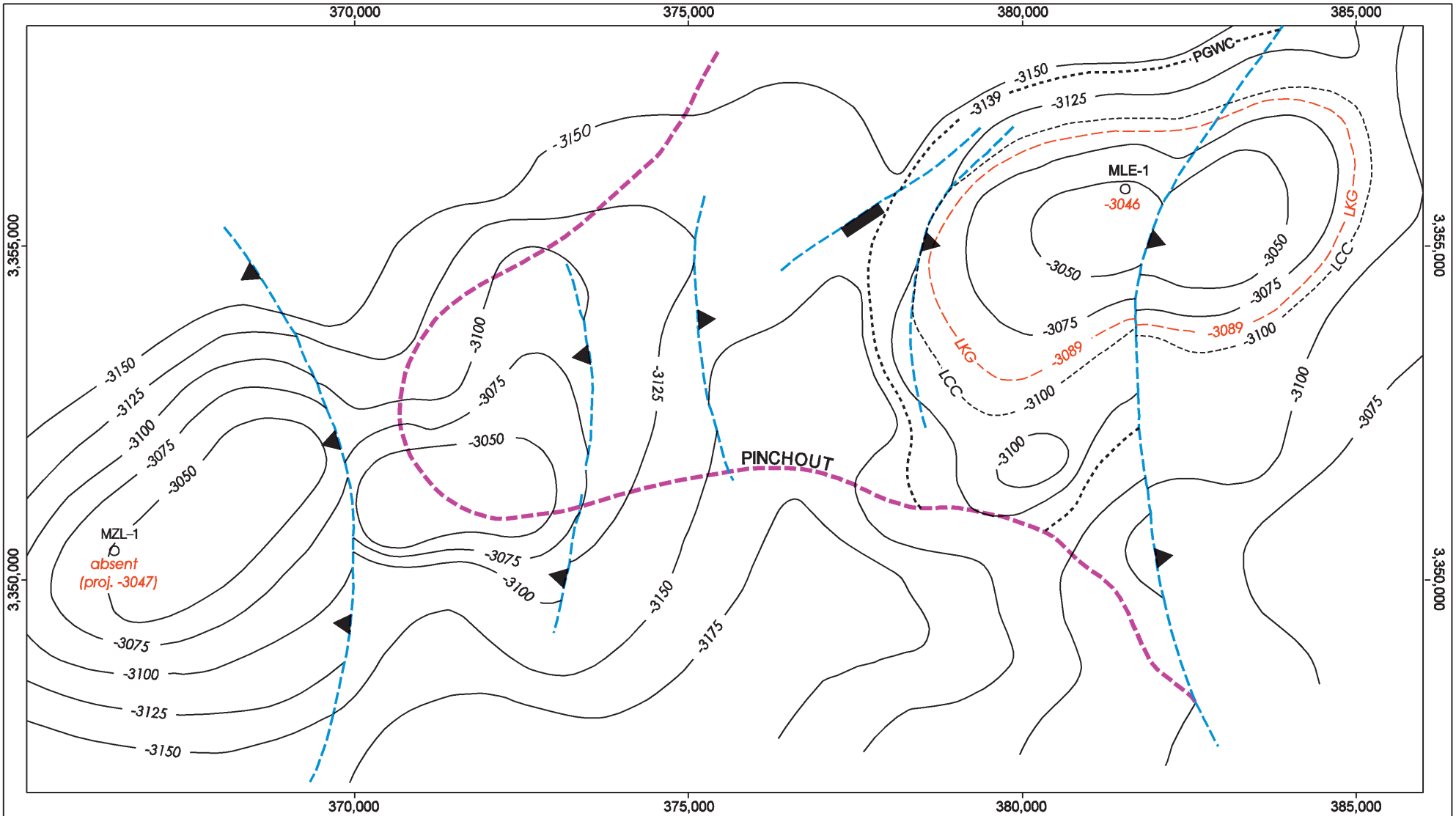

FIGURE 3
STRUCTURE MAP
F1 SAND
MENZEL LEDJMET AREA
ALGERIA
CONTOUR INTERVAL: 25 METERS
SCALE
0 1000 2000 3000 4000 5000
METERS
DEGOLYER AND MACNAUGHTON, DALLAS, TEXAS
DECEMBER 2001